Business Case for Investment Decision by BC Hydro Board of Directors

SITE C CLEAN ENERGY PROJECT

December 2014

EXECUTIVE SUMMARY

This Business Case has been prepared for the BC Hydro Board of Directors (Board) to inform the investment decision for the Site C Clean Energy Project (Site C). It contains a synopsis of information that has previously been presented in different forums during the development phase of Site C, together with recent updates on the analysis of need and alternatives.

BC Hydro's 2012 long-term mid-load forecast projects that electricity demand in B.C. will increase by approximately 40 per cent over the next 20 years, excluding any load from liquefied natural gas (LNG) facilities and before accounting for Demand Side Management (DSM) energy and associated capacity savings. Load from new LNG facilities that may request service from BC Hydro would further increase this load. BC Hydro looks to DSM as its first resource to meet customer demand, and the approved 2013 Integrated Resource Plan (IRP) sets an aggressive DSM target of 7,800 gigawatt hours per year (GWh/year) of energy savings and 1,400 megawatts (MW) of associated capacity savings by Fiscal (F) 2021:

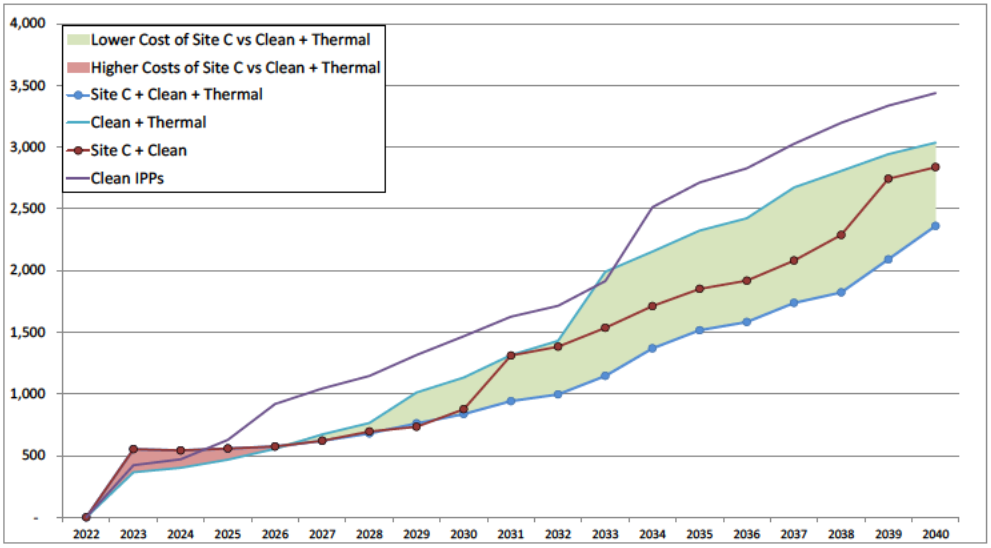
- With DSM, it is projected that there will be a shortfall in BC Hydro's ability to meet peak capacity demand commencing in 2019, and a shortfall in total supply of energy commencing in 2022, using a mid-range load forecast and an expected LNG demand of 3,000 GWh/year.
- With DSM and without LNG the capacity shortfall remains the same (2019) and the energy shortfall is 2028.

In order to meet these energy and capacity Load-Resource Balance (LRB) gaps, additional resources are required to meet both the energy and capacity needs of BC Hydro's customers.

Based on the analysis of alternative resource options, Site C provides the best combination of financial, technical, environmental and economic development attributes and is therefore the preferred option to meet the need for energy and dependable capacity within BC Hydro's planning horizon. Site C was identified as having the lowest levelized Unit Energy Cost (UEC) at $82 per megawatt hour (MWh), the lowest present value (PV) of costs under expected conditions, the lowest projected impact on ratepayers, and the lowest level of greenhouse gas (GHG) emissions from all of the portfolios of alternatives considered.

From a ratepayer's perspective, the Site C portfolio is a compelling option. Due to its relatively higher upfront costs compared to alternative portfolios, there is a brief period following the in-service date where the cost of service is higher than alternatives. However, after approximately four years in service and for the remainder of the 20-year forecast period, the Site C portfolio has a far lower ongoing cost of service than any other portfolio combination. This is because Site C's capital costs trend downward over time as the impact from the amortization of capital costs are eroded by inflation. The other portfolios continue to rise in costs, whether due to increased costs from Independent Power Producer (IPP) calls, the inflationary effects of having capital expenditures, or ongoing fuel input costs in the future, making the financial benefits of the Site C portfolio more pronounced as time passes.

As illustrated in the graph on the following page, the long-term savings to ratepayers average approximately [redacted] per year in the period from 2030-2040, and would continue to grow for the remainder of Site C's projected life of over 100 years.



In addition to its advantages to ratepayers, specific project benefits include:

- Site C would be a cost-effective clean, renewable and reliable power resource that would provide long-term energy, dependable capacity and other system benefits to the BC Hydro's power grid.
- The construction of Site C would create jobs, provide a boost to provincial Gross Domestic Product (GDP) and increase revenues for all levels of government.
- As the third project on the Peace River, Site C would optimize BC Hydro's existing resources — generating 35 per cent of the energy of the W.A.C. Bennett Dam, with only 5 per cent of the reservoir area. It would produce among the lowest GHG emissions, per gigawatt hour, and help integrate intermittent renewables into the provincial power grid.
- Among the benefits to local communities from Site C are a regional legacy benefits agreement, infrastructure improvements, recreation and tourism opportunities, and affordable housing.
- Aboriginal groups are expected to see economic and social development benefits through Impact Benefit Agreements negotiated with BC Hydro, which may consist of:
  - Lump sum cash payments or payment streams over time
  - Work and contract opportunities, including potential directed procurement
  - Crown land transfers
  - Implementation of land protection measures or special land management designations

Site C will form a major component in meeting BC Hydro's customer's future needs for energy and dependable capacity. The project provides the best combination of financial, environmental and technical characteristics that are consistent with both BC Hydro's vision and the Province's legislated requirements. In light of all of these characteristics, BC Hydro recommends building Site C for its earliest in-service date (ISD) of F2024.

Table of Contents

Tables

Figures

1. Introduction

This Business Case has been prepared for the BC Hydro Board of Directors to inform the investment decision for the Site C Clean Energy Project. It contains a synopsis of information that has previously been presented in different forums during the development phase of Site C from the Environmental Impact Statement (EIS), the 2013 Evidentiary Update, the December 2012 Load Forecast, the 2013 IRP and other supporting documents as detailed in Section 7.2. There is also new information in the form of the May 2014 load forecast update, together with recent updates on the analysis of need and alternatives. Updated analysis has been prepared as a result of consultation with Clean Energy BC (CEBC) regarding IPP alternatives to Site C in July – October 2014, consultation with Treaty 8 Tribal Association (T8TA) on need and alternatives in September/October 2014, and recent requests from the Ministry of Energy and Mines to inform a provincial Final Investment Decision on Site C.

The Business Case is structured to highlight the methodology used to arrive at the recommendation to build Site C. Section 2, following this introduction, provides a basic project description of Site C covering technical specifications and estimated cost. A description of the need that Site C is designed to meet, namely to fill the energy and capacity gaps that are expected to occur over the next 20 years between BC Hydro's existing generation resources and customer demand for electricity, is contained in Section 3. Section 4 provides an analysis of the various resource options, grouped into portfolios, that are technically and economically feasible to meet the identified gaps, and describes the criterion used to determine that the portfolio containing Site C is the preferred option. Alternative ways of delivering on the Site C project are examined in Section 5, and Section 6 outlines the various benefits associated with the construction of the Site C project. The Business Case concludes with a listing of various reference materials. Appendices are provided which include more detailed information than has been provided in this report.

The original Business Case for the Final Investment Decision was provided to the BC Hydro Board of Directors in October 2014. Subsequent to the Board's decision, additional work was undertaken:

- Detailed analysis of the consequences of a delay to Site C was undertaken and is provided in Appendix I-2.
- Further consultation was undertaken with T8TA regarding need and alternatives to the Site C. Appendix J has been updated to reflect this additional consultation.
- Further economic analysis was performed in support of the Provincial Government's Final Investment Decision. This additional analysis is collected in Appendix K.

2. Background and Context

This section describes some of the technical specifications of the Site C project, providing a description of the project and the total estimated project cost. This section also provides a brief synopsis of some of the key project milestones and target dates.

2.1. Project Description

The proposed project is a third dam and hydroelectric generating station on the Peace River in northeast B.C. Key components are listed below:

- An earthfill dam, approximately 1,050 metres long and 60 metres high above the riverbed.
- A generating station with six 183 MW generating units.
- A new substation near the Site C dam site and expansion of GIS Building at Peace Canyon.
- Clearing and filling of an 83-kilometre-long reservoir that would be, on average, two to three times the width of the current river.
- Property acquisitions and relocations.
- The realignment of six segments of Highway 29 over a total distance of approximately 30 kilometres and increased shoreline protection at Hudson's Hope.
- Two new 500 kilovolt AC transmission lines that would connect the Site C facilities to the Peace Canyon Substation, along an existing right-of-way.
- Access roads in the vicinity of the site and a temporary construction access bridge across the Peace River.
- Construction of temporary cofferdams across the main river channel to allow for construction of the earthfill dam and two diversion tunnels.
- Worker accommodation at dam site, with other workers housed off site and in the region.
- Other supporting facilities and services at the dam site.

Figure 1 Artist Rendering of the Proposed Site C Dam and Generating Station

2.2. Cost Estimate

The project's total cost estimate was publicly released in the Project Description Report at [redacted], and included reserve amounts to absorb impacts due to inflation over the projected construction period. All development, regulatory and mitigation costs, including all costs spent to date, are included as part of the indirect costs. The cost estimate has been prepared following recommended industry practice in accordance with AACE International Class 3 level of accuracy typically used for budget approval and investment decisions. A summary breakdown of key component areas of the cost estimate is presented in Table 1.

Table 1 Project Cost Estimate

Project Cost Estimate Component	**Cost Estimate** *(in millions)*
Total Direct Construction Costs (F2011 dollars)	$ [redacted]
Indirect Costs (F2011 dollars)	$ [redacted]
Contingency (F2011 dollars)	$ [redacted]
Total Construction and Development Costs (F2011 dollars)	**$** [redacted]
Inflation	$ [redacted]
Interest During Construction	$ [redacted]
Total Construction and Development Costs (nominal dollars)	**$** [redacted]

* Note that decisions made during the Provincial Government FID result in a revised cost estimate of [redacted], with an additional [redacted] reserve held by the Provincial Treasury Board. Details of this change are provided in Appendix K.

From the date of issue of the cost estimate in 2010 through to the date of this Business Case, there has been significant ongoing design and development work that has produced changes and refinements to the various project components. These factors in turn have resulted in both positive and negative changes to the aggregated cost estimate line items displayed in Table 1. In addition, cost estimates have been updated to reflect current knowledge of market conditions for materials and labour where they have differed from previous assumptions. The accuracy range of the cost estimate is tighter than the outer range of a Class 3 estimate as the design has advanced since 2010. The most recent update that reflects all of these changes was completed in June of 2014, and confirmed that the project cost estimate of [redacted] remains valid.

As part of its due diligence BC Hydro engaged a panel of industry experts[1] to undertake an independent review of the direct cost estimate, and provide an opinion regarding its completeness, sufficiency and accuracy. The panel's review ("Independent Review of Direct Construction Cost Estimate (September 2014) ") concluded that the cost estimate is: sufficient for the proposed scope and schedule of Site C; an appropriate level of accuracy for making a final investment decision; and there are some opportunities for cost reduction available.

[1] The panel assembled for the review included experts with 35 to 50 years' experience in the construction of earthfill dams, Reinforced Concrete structures, hydraulic tunnelling, generating stations, spillways and other heavy civil works.

2.3. Schedule and Milestones

Site C entered the harmonized co-ordinated federal-provincial environmental assessment process in August 2011. The Environmental Impact Statement (EIS) for the project was submitted in January of 2013, and the Joint Review Panel (JRP) Hearings were completed in January of 2014. The resulting JRP report was made publicly available on May 1, 2014. On 14 October 2014, the federal Minister of Environment released the Decision Statement approving Site C with conditions, and the B.C. Ministers of Environment and of Forest, Lands and Natural Resources granted BC Hydro an Environmental Assessment Certificate (EAC) for Site C. Current expectations around future selected project milestone dates are presented in Table 2.

Table 2 Project Milestones

Milestone	Target Date
Regulatory Process	
EA Certificate Granted/ Issued	Oct 2014
Financial Approvals	
Investment Decision - BOD	October 2014
Investment Decision - Provincial Government	December 2014
Regulatory & Permitting	
Land Base Authorizations	Jan 2015
Water Based Authorizations	March 2015
Implementation	
Dam site clearing start	Jan 2015
Worker Accommodation Operational	Dec 2015
MCW Mobilization	Nov 2015
MCW Complete Diversion Tunnels	Dec 2018
MCW River Diversion Start	Sep 2019
Transmission Line 5L5 Complete (PCN to FSJ)	Jan 2020
Highway 29 Realignment Complete	Sep 2021
Transmission Line 5L6 Complete (PCN to STC)	Jun 2022
Commissioning	
Unit 1 Commissioning Wet (First Unit In Service)	Dec 2022
Unit 6 Commissioning Wet (All Units In Service)	Nov 2023

* The project schedule was adjusted as part of the Government decisions associated with the Provincial FID. This revised schedule delays most components of the project schedule by approximately 12 months. Please refer to Appendix K for further discussion.

3. Issue Definition – Need for Energy and Capacity

This section describes the key driver behind BC Hydro's need for additional resources, the growing demand for electricity from customers, and the methodology for determining this need. It discusses actions that BC Hydro is able to take to address this need, highlights existing resource capabilities, and provides figures for the estimated difference between customers' need for energy and dependable capacity, and what BC Hydro can supply with existing and committed resources.

3.1. Load Forecast

BC Hydro has an obligation under the *Utilities Commission Act* to meet the electricity needs of its customers within the framework established by the *Clean Energy Act* (see Section 6.6 of this document for more information). To fulfil this obligation, BC Hydro develops and regularly updates a long-term load forecast to project future needs for energy and capacity resources. The energy forecast represents the forecasted total annual electricity demand for the integrated system, and the peak forecast represents the one-hour maximum demand on the integrated system.

The base case analysis of Site C and alternatives is based on BC Hydro's mid-load forecast for both energy and peak demand. The mid-load forecast represents the expected future load, in which actual realized loads are projected to be higher than forecast 50 per cent of the time, and lower than forecast 50 per cent of the time.

The analysis of Site C is based on BC Hydro's December 2012 Load Forecast. The May 2014 load forecast update forecasts increased load compared to the 2012 load forecast and does not modify the conclusions of the existing analysis due to an offsetting increase in IPP supply side contributions. See Section 3.1.2 for additional detail on the updated 2014 forecast, and section 3.2 for a discussion of existing and committed supply side resources.

3.1.1. December 2012 Load Forecast

The 2012 Load Forecast was prepared in accordance with the British Columbia Utilities Commission's (BCUC) Resource Planning Guidelines and decisions. BC Hydro's load forecasting methodology has been the subject of independent review in a number of BCUC regulatory proceedings, and the BCUC has accepted BC Hydro's load forecasting methodology for both long-term planning and capital project advancement purposes.

As part of its due diligence BC Hydro commissioned a third party review of its load forecast methodology by Mark P. Gilbert. The review ("Review of BC Hydro Electric Load Forecast Methodology, British Columbia Hydro and Power Authority") concluded that BC Hydro's load forecast methodology is representative of good utility practice, and that forecasts track actuals well except in circumstances of major and unpredictable events such as the great recession of 2008. BC Hydro compared recent actual demand to that predicted in the December 2012 Load

Forecast. BC Hydro slightly under-forecasted demand for both F2013 (by 0.2%) and F2014 (by 1%).[2]

The 2012 Load Forecast is based on analysis that incorporates the most current third-party economic indicators available. Many inputs are provided by external sources such as the B.C. Ministry of Finance and Stokes Consulting for GDP forecasts, and sector-specific experts for the forestry, mining, and oil and gas industries. The key drivers of the 2012 load forecast, by customer group, are as follows:

- **Residential:** BC Hydro's forecast of demand from residential customers is driven by forecasts of the average annual use of electricity per account and the number of accounts, which in turn is driven by population growth and housing starts. The average use per account is developed using an end use model that includes economic drivers such as disposable income, people per account, and efficiency trends for the primary residential end uses of electricity.
- **Commercial:** The drivers of the commercial forecast include average commercial end use efficiencies trends and projections of retail sales, employment and commercial output.
- **Industrial:** BC Hydro prepares its industrial transmission load forecast on a customer-by-customer basis. A projection of industrial distribution sales is developed for key sectors – including forestry (including pulp and paper), mining (coal), and oil and gas – based on production forecasts for each major industrial customer. The remaining industrial distribution sales are developed using an econometric model and provincial GDP growth as a load driver.

The 2012 Load Forecast also includes consideration of the following factors that influence demand reduction:

- **Demand-Side Management:** The 2012 Load Forecast reflects the impact of savings from BC Hydro's past DSM initiatives such as energy conservation achieved through F2012. Future projected DSM savings from F2013 onward are accounted for separately as assumed future actions (as discussed in Section 3.3.1).
- **Impact of Forecast Rate Increases (elasticity effects):** The 2012 Load Forecast reflects expected changes to customer demand resulting from changes to BC Hydro rates.

BC Hydro's 2012 long-term mid-load forecast projects that electricity demand in B.C. will increase by approximately 40 per cent over the next 20 years, excluding any load from LNG facilities and before accounting for DSM. Load from new LNG facilities that may request service from BC Hydro would further increase this load.

[2] Note that these values are net of rate increase impacts and BC Hydro's DSM initiatives.

Table 3 Mid-Load Forecast Before DSM (Selected Years)

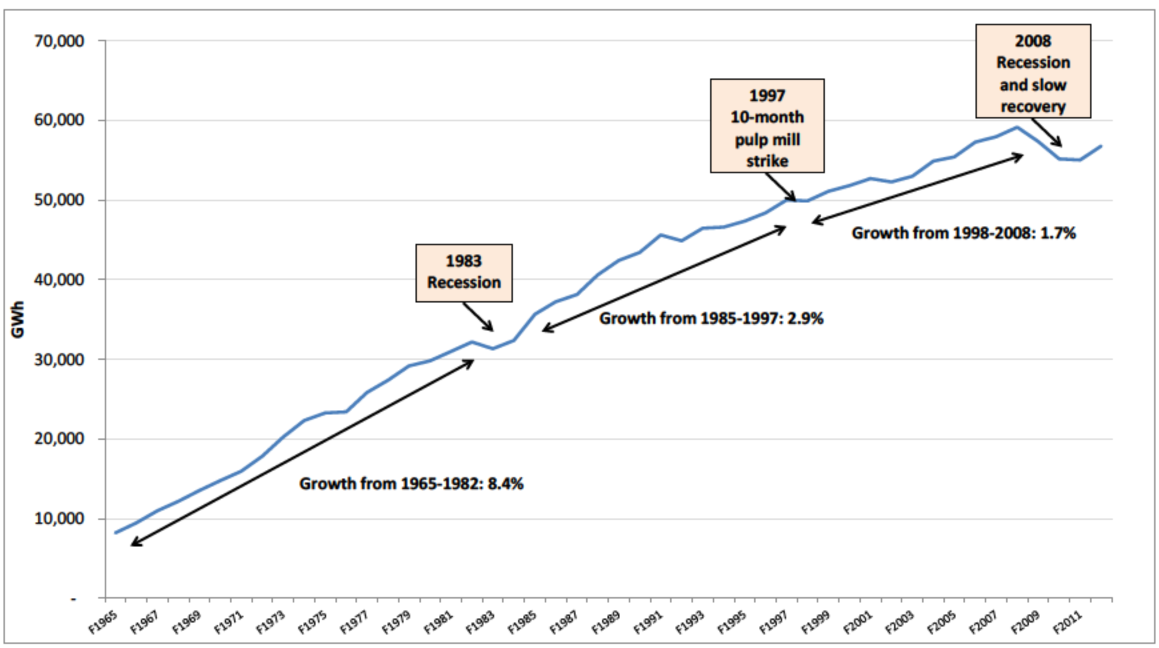
Component of Load		F2017	F2024	F2028	F2033	Average Annual Growth Rate F2014–33
Without LNG	Energy (GWh)	63,200	72,700	75,500	80,300	1.7%
	Peak Capacity (MW)	11,700	13,150	13,800	14,900	1.6%
With Expected LNG	Energy (GWh)	63,200	75,700	78,500	83,300	1.9%
	Peak Capacity (MW)	11,700	13,500	14,200	15,300	1.7%

Note: F2014 Load was forecast to be 58,700 GWh and 11,000 MW

In addition to the above forecast, BC Hydro undertook separate consideration of potential load from new LNG facilities. For planning purposes, BC Hydro examined a range of LNG demand between approximately 800 to 6600 GWh/year (100 to 800 MW), with 3,000 GWh/year (360 MW capacity) being an expected amount. BC Hydro's estimate of LNG demand is based on some proponents using grid power for their ancillary needs (about 15-20 per cent of total energy requirements), some generating their own power on site and others taking BC Hydro power for both compression and ancillary energy needs.

Except for unusual events such as the 2008 recession, actual long-term load growth in the past has trended higher than BC Hydro's current long-term projection. Figure 2 shows the historical load growth in BC over the past 50 years.

Figure 2 Historical Customer Demand (F1965-F2012)



3.1.2. May 2014 Load Forecast Update

In May 2014, BC Hydro finalized a new long-term load forecast. The update indicates an energy and peak increase of 2 to 3 per cent relative to the previous forecast. The major updates to the forecast include:

- Lower rate projection reflecting the B.C. Government's 10-Year Rate Plan for BC Hydro announced in November 2013. This results in a lower rate-induced reduction in sales.
- Residential and commercial sales forecasts are modestly lower due to updated efficiency projections, in particular lighting.
- Forecast industrial sales are significantly higher, largely due to shale gas developments in northeast B.C.
- The increase indicated above is before the inclusion of expected LNG-related demands. The expected or base case LNG demand of approximately 3,000 GWh/year (360 MW peak capacity) remains unchanged in the mid to long-term period of the forecast.[3]

3.2. Existing and Committed Supply

The energy and capacity from BC Hydro's existing and committed resources include BC Hydro's heritage hydroelectric and thermal resources, and IPPs.

- *Heritage Hydroelectric and Thermal Resources:* BC Hydro has 31 existing hydroelectric facilities connected to the integrated system. By 2033, BC Hydro's 31 existing hydroelectric facilities are expected to supply approximately 48,500 GWh/year of energy and 11,400 MW of capacity, including planned upgrades to these facilities.[4]

  Prince Rupert Generating Station is the only BC Hydro-owned thermal generating station expected to serve the integrated system by 2020, and supplies only a modest amount of energy and capacity.

- *Existing and Committed IPP Supply:* As of January 1, 2014, BC Hydro manages 83 Energy Purchase Agreements (EPAs) for IPPs in commercial operation (currently producing 25 per cent of BC Hydro's energy supply) with an additional 44 EPAs for projects in the pre-commercial operation stage. BC Hydro's existing and committed contracts with IPPs are expected to supply approximately 7,900 GWh/year of firm energy and approximately 500 MW of peak capacity by F2033.

[3] On 13 May 2014, Woodfibre LNG announced that its proposed liquefaction project to be sited in Squamish, B.C. will run off electric power provided by the BC Hydro system. If it proceeds, Woodfibre LNG's facility will likely require electricity corresponding to or exceeding the low LNG scenario of 800 GWh/year (100 MW). In addition, FortisBC Inc. is expanding its Tilbury LNG facility in Delta, B.C. which would add to the load BC Hydro would serve.

[4] This includes BC Hydro capital projects planned and underway, such as the Ruskin Dam and Powerhouse Upgrade Project, the John Hart Generating Station Replacement Project and Mica Units 5 and 6.

3.3. Actions Assumed to be Undertaken Prior to Site C

The following actions are assumed to be undertaken irrespective of the decision on whether to proceed with Site C, and are therefore reflected in the evaluation of the need for energy and capacity.

3.3.1. Demand-Side Management

BC Hydro plans to meet approximately 78 per cent of its load growth through conservation and efficiency initiatives. BC Hydro uses three main tools to achieve its DSM targets: codes and standards; conservation rate structures; and programs designed to address remaining barriers to energy efficiency and conservation.

The current DSM target is to achieve 7,800 GWh and 1,400 MW of electricity in F2021, with a potential of 11,000 GWh of energy savings and 2,100 MW of capacity savings in F2033. This is expected to reduce forecast incremental energy demand by 78 per cent in F2021 excluding LNG load (69 per cent with expected LNG load), above the *Clean Energy Act* objective of at least 66 per cent. BC Hydro is among the leading jurisdictions (including California public utilities) as measured by DSM spending as % of retail sales. Appendix C provides a review of BC Hydro's DSM activities compared to other jurisdictions.

BC Hydro reviewed the possibility for additional DSM activity in the analysis of alternative resource options discussed in Section 4.

3.3.2. IPP Renewals and New Contracts

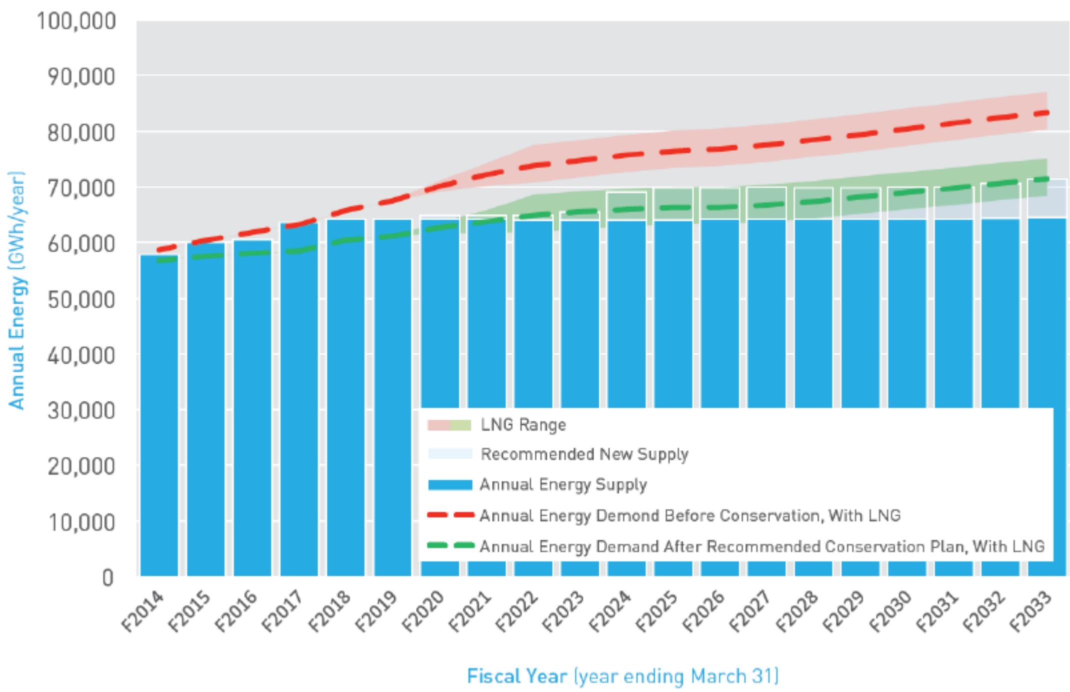
BC Hydro has assumed the following activities related to IPP contracts will proceed irrespective of Site C.

- *Standing Offer Program* (SOP): BC Hydro's long-term plan includes an increase to the SOP annual target from 50 GWh/year to 150 GWh/year to enable more small-scale projects throughout BC Hydro's service area. Future SOP activity could, by 2033, contribute approximately 1,400 GWh/year of energy and 110 MW of capacity.
- *Agreements with First Nations*: BC Hydro has Impact Benefit Agreements (IBAs) with First Nations, some of which involve consideration of EPAs for generation projects. Projects associated with IBAs could contribute approximately 170 GWh/year of energy and 25 MW of capacity by 2033.
- *IPP Renewals:* As EPAs expire for projects already in operation, BC Hydro is targeting renewal of the contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. By 2033, it is expected that renewals of IPP contracts could amount to 6,360 GWh/year of energy and 640 MW of capacity beyond the existing and committed supply.

3.4. Load-Resource Balance Gap

The LRB gap is evaluated as the difference between forecast BC Hydro customer demand (i.e. the load forecast) and the expected available resources to satisfy this demand (i.e. the existing and committed resources, plus the actions assumed to be undertaken prior to Site C). The LRBs are evaluated for both energy and capacity requirements of BC Hydro customers. Figure 3 shows the forecast energy LRB (with and without the DSM target, and with a range of LNG scenarios). Additional detail on LRBs is provided in Appendix B.

Figure 3 Forecast Energy Load-Resource Balance (F2014-F2033)



As shown in Table 4, additional resources are required to meet the energy and capacity needs of BC Hydro customers, even when taking into account BC Hydro's aggressive DSM target, new and renewed IPP contracts and excluding LNG. There is a need for new capacity resources in F2019 and a need for new energy resources in F2022 with expected LNG.

Table 4 Timing of Requirement for Additional Energy and Capacity Resources

LNG Scenario	Energy Need	Capacity Need
No LNG	F2028	F2019
Low LNG (800 GWh/yr)	F2024	F2019
Expected LNG (3,000 GWh/yr)	F2022	F2019
High LNG (6,600 GWh/yr)	F2021	F2019

Note: The above timing of requirements assumes BC Hydro achieves its DSM Target

Table 5 Mid-Load Forecast After DSM Target (Selected Years)

Component of Load		F2017	F2024	F2028	F2033	Average Annual Growth Rate F2014–33
Without LNG	Energy (GWh)	58,500	62,900	64,400	68,400	1.0%
	Peak Capacity (MW)	10,850	11,450	11,850	12,750	0.9%
With Expected LNG	Energy (GWh)	58,500	65,900	67,400	71,400	1.2%
	Peak Capacity (MW)	10,850	11,800	12,250	13,150	1.1%

Note: F2014 Load was forecast to be 56,800 GWh and 10,700 MW including DSM

The 1 per cent annual growth in electricity demand after the DSM target but without any LNG load is in line with other North American forecasts such as the U.S. Energy Information Administration's Annual Energy Outlook and the 0.85 per cent growth rate per year in Itron's broad-based November 2013 survey entitled "Energy Trends: Benchmarking Survey 2012" covering more than half of North American load.

4. ANALYSIS OF ALTERNATIVE RESOURCE OPTIONS

BC Hydro undertook analysis to determine whether Site C was a preferred option to meet the need for energy and capacity described in Section 3. This analysis compared Site C to other available resources in BC according to both financial and non-financial considerations. This section describes the methodology and results of the analysis of alternative resource options.

BC Hydro engaged a third party – Synapse Energy Economics Inc. – to review the methodology associated with its analysis of the alternatives. This third party review ("Review of BC Hydro's Alternatives Assessment Methodology") concluded that BC Hydro's alternatives analysis methodology and tools are consistent with good utility practice. As noted below, this third party review also endorsed specific financial assumptions. BC Hydro also vetted its alternatives assumptions with the B.C. Ministry of Energy and Mines as part of the exchange of information with CEBC in the summer and fall of 2014. Appendix E-2 provides additional details on financial assumptions and sensitivity cases, including BC Hydro's view of the assumptions used by CEBC's consultant. Alternatives to Site C were also a subject of additional consultation with T8TA, who expressed interest in several alternatives to Site C including capacity-focused DSM, wind, geothermal, and natural gas. Appendix J provides a more detailed discussion of BC Hydro's consideration of comments received through these consultation processes.

4.1. Key Assumptions

4.1.1. Financial Assumptions

- **Cost of Capital:** The cost of capital is used to determine the levelized costs (UECs and UCCs) of generation resources. A different cost of capital was applied based on the developing entity to recognize the different borrowing rates of IPPs and the B.C. Government[5]:
  - A 5 per cent cost of capital was used to calculate the levelized costs of BC Hydro generation resources.
  - A 7 per cent cost of capital was used to calculate the levelized costs of IPP generation resources.
- **Discount Rate:** Consistent with BCUC guidance documents,[6] a 5 per cent discount rate was based on BC Hydro's Weighted Average Cost of Capital (WACC) and used to calculate the PV of portfolio costs for the financial analysis described in Section 4.3. A single discount rate was applied to all resource cashflows.

[5] BC Hydro undertook an economic analysis in the IRP and used what it believed to be the overall financial cost of BC Hydro and the WACC from its IPP intelligence. All of the future WACC estimates were done on a forecast debt cost for the next 10 years of 4.8% nominal. As a result, BC Hydro had a WACC of 5% real (using a 70/30 debt/equity ratio) and IPPs 7% real for a WACC differential of 2%. BC Hydro also undertook a sensitivity on which the WACC differential is reduced to 1%. The review of BC Hydro's alternatives assessment methodology found that BC Hydro selected reasonable values for its own WACC and for the IPP WACC.

[6] See, for example, the BCUC's *Utility System Extension Test Guidelines*, section 2.

- **Inflation Rate:** For conversion between nominal and real dollars a 2 per cent inflation rate was assumed based on forecasts for the B.C. Consumer Price Index.

4.1.2. Energy Market Prices

Market prices drive the analysis of alternatives in three main ways:

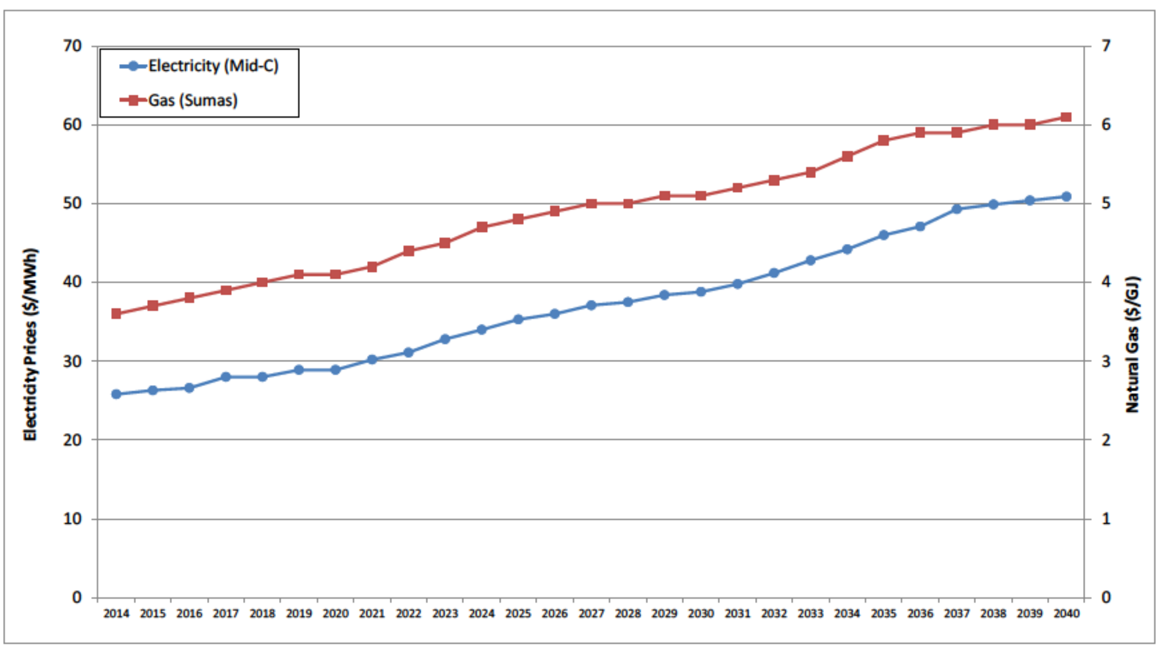
- Electricity: valuation of surplus energy
- Natural Gas: cost of fuel for natural gas-fired generation
- GHG Emissions Cost: cost of carbon tax or offsets for generation resources that produce GHGs during operations (such as natural gas-fired generation)

The market price forecasts are based on third party (Ventyx) scenarios and are presented in the 2013 IRP. The base case analysis of Site C was performed using a reference case market forecast (Market Scenario 1), with the following characteristics (values in Canadian dollars):

- An electricity spot market forecast of approximately [redacted]/MWh in F2024 growing to about [redacted]/MWh by F2033.
- A natural gas spot market forecast of about [redacted]/gigajoule (GJ) in F2024 growing to about [redacted]0/GJ by F2033.
- Forecast GHG emissions costs of [redacted]/tonne, escalated at inflation.

Figure 4 shows market prices in the reference case.

Figure 4 Electricity and Natural Gas Prices – Reference Case



Note: Values above are in F2013 Canadian dollars

The spot market price of both electricity and natural gas is highly variable due to uncertainties of supply, demand and government policies. As a result, BC Hydro conducted a sensitivity analysis on a range of potential market scenarios, which is discussed in Section 4.6.

Appendix D provides additional details on the market price forecasts in both the reference case and sensitivity cases.

4.1.3. Bridging Assumptions

There is a need for new capacity resources prior to Site C's earliest ISD in both the no LNG and expected LNG load scenarios, and a need for new energy resources prior to Site C in the expected LNG scenario. As a result, resources are required to serve load until Site C enters service.

No LNG: There is a need for capacity between F2019 and F2023, and the 2013 IRP recommends securing Cabinet approve to permit short-term reliance on the market for up to 300 MW to meet any system capacity shortage during this 5 year period because the reliance is for a short period of time.

Expected LNG: The approved 2013 IRP recommends using market purchases to bridge the 1,500 GWh expected LNG load scenario energy need and the 300 MW no LNG load scenario capacity need before Site C. However, there is a 700 MW capacity gap in the expected LNG scenario prior to Site C's in-service date. BC Hydro reviewed two options for meeting the incremental 400 MW expected LNG capacity needs prior to Site C as follows:

- Option 1: Implement a 700 MW reliance on external markets for capacity needs prior to Site C;
- Option 2: Limit reliance on external markets prior to Site C to 300 MW and construct 400 MW of gas-fired generation capacity in the North Coast in support of significant load growth and single transmission circuit supply.

The main concern and trade-off in determining the degree of market reliance was the limit of market access (typically limited to 500 MW) and the uncertainty in loads and DSM capacity contribution compared to the higher costs of Option 2 versus Option 1. Post-IRP it has been determined that BC Hydro should pursue Option 2. Option 2 results in the overall portfolio costs being slightly higher, and also results in a change to the comparative PV costs of Site C portfolios compared to alternative portfolios. This updated PV analysis is reflected in Section 4.3.

4.1.4. Characterization of Resource Options

The identification and characterization of potential resource options to meet the need for energy and capacity was done as part of the 2013 Resource Options Update (ROU). The 2013 ROU is a database of resource option attributes and costs reflecting: (1) input from stakeholders with technical expertise, including information from members of the IPP community, as well as

First Nations and public stakeholders; (2) consultant studies; and (3) BC Hydro's own project experience.

4.2. Viable Alternatives

4.2.1. Screened Resources

An initial screening of the options identified in the 2013 ROU was undertaken with the following considerations:

- **Barred resources:** Resources that are not permitted by or are inconsistent with B.C. Government legal requirements or policy (e.g., prohibited by the *Clean Energy Act*)
- **Not technically or economically feasible:** Resources that are either not technically feasible within the planning period, or whose cost would render them economically infeasible when compared to other available resources.

Table 6 shows those resource options that were screened during this initial process.

Table 6 Screened Resources

Technology	Reason for Screening
Demand-Side Management Options beyond current DSM Target	
DSM Options 4 and 5	Technical/Economic Feasibility
DSM capacity-only initiatives	Technical/Economic Feasibility Partially Outside Government Policy (mandatory time of use (ToU) rates)
Supply-Side Options	
Wave	Technical/Economic Feasibility
Tidal	Technical/Economic Feasibility
Solar	Economic Feasibility
Geothermal	Technical/Economic Feasibility
Large hydroelectric (other than Site C)	Outside Government Policy
Nuclear	Outside Government Policy
Coal-fired generation with carbon capture and storage	Technical/Economic Feasibility
Burrard Thermal Generating Station	Outside Government Policy
Imports from External Markets	Outside Government Policy

4.2.2. Available Resources

Subsequent to the screening undertaken the remaining resources were identified as Available Resources that were candidates for inclusion in Portfolio Analysis. Table 7 shows the Available Resources considered, along with some key technical characteristics. These attributes are:

- **Capacity:** Whether the resource provides dependable capacity or is an intermittent resource.
- **Flexible:** Whether the resource is flexible to respond to short-term fluctuations in demand through dispatch capability
- **Energy:** Whether the resource provides energy to the system.
- **Seasonal Profile:** The nature of the profile of generation throughout the year.

Table 7 Generation Characteristics of Available Resource Options

Technology	Capacity	Flexible	Energy	Seasonal Profile
DSM Options				
DSM Option 1	Dependable	No	Yes	Similar to load
DSM Option 3	Dependable	No	Yes	Similar to load
Clean or Renewable Resources				
Site C	Dependable	Yes	Yes	Matched to load
Wind (on-shore and off-shore)	Intermittent	No	Yes	Similar to load
Run-of-river hydro	Intermittent	No	Yes	Primarily freshet
Wood-based Biomass	Dependable	No	Yes	Flat
Municipal Solid Waste	Dependable	No	Yes	Flat
Pumped storage	Dependable	Yes	Consumption	n/a
BC Hydro Resource Smart[7]	Dependable	Yes	Minimal	n/a
Thermal (Fossil Fuel) Resources				
Natural gas-fired Simple Cycle Gas Turbines (SCGTs) - Peakers	Dependable	Yes	Yes	Matched to load
Natural gas-fired Combined Cycle Gas Turbines (CCGTs) - Baseload	Dependable	No	Yes	Seasonally flat

Note: Thermal (Fossil Fuel) Resources are within 93 per cent *Clean Energy Act* clean/renewable target

Electricity from many IPPs is intermittent (i.e., not always available when required). As such, the dependable capacity provided is a small fraction of the installed capacity. Refer to Appendix H for further discussion.

[7] i.e. upgrade projects to existing generation facilities

4.2.3. Portfolio Composition

Utilizing the viable alternative resources outlined above, BC Hydro established three sets of alternatives to be evaluated through portfolio analysis. These portfolios represent different technically feasible strategies by which BC Hydro would be able to meet customer demand.

The portfolio options evaluated were as follows:

- **Site C Portfolios**, in which Site C is built and additional clean or clean and thermal resources are procured to meet load beyond that served by Site C.
- **Clean Generation Portfolios**, in which Site C is not built and clean or renewable alternatives are procured instead. Generally these portfolios consist of a mix of wind, municipal solid waste, and wood-based biomass resources providing energy, with the addition of a sixth unit at Revelstoke Generating Station (Revelstoke 6), upgrades to Units 1-5 at G.M. Shrum Generating Station (GMS Units 1-5), and pumped storage providing required capacity.
- **Clean + Thermal Portfolios**, in which Site C is not built and a combination of clean or renewable and thermal alternatives are procured instead. Generally these portfolios consist of a mix of wind, municipal solid waste, and wood-based biomass resources providing energy, with Revelstoke 6, GMS Units 1-5, and SCGTs providing the majority of required capacity.
  - BC Hydro also created a subset of the Clean + Thermal portfolio in which DSM Option 3 is pursued in order to test the economics of additional energy-focused DSM.

4.3. Financial Analysis

The financial comparison of alternatives is largely done through portfolio modelling. Portfolios are created by a linear optimization model (“System Optimizer”) that selects the optimal combinations of available resource options under different assumptions and constraints that will meet the energy and capacity needs of BC Hydro’s customers. Portfolio modeling takes into account economic considerations of the potential portfolio in a way that looking at resource UEC comparisons cannot. The portfolio modeling allows the following considerations:

- Timing of resource additions, including transmission additions or upgrades and associated capital and operating expenditures;
- Effects of resource additions to the overall system and the system load resource balance over the planning horizon;
- Economic dispatch reflecting the manner in which dispatchable resources will be operated;
- Electricity market trade benefits that vary with the flexibility of the overall portfolio; and
- Permits the calculation and comparison of a portfolio PV to allow 30 year planning timeframe cost comparisons.

It should be noted that a main drawback of the portfolio modeling approach is that there is an inherent assumption that perfect foresight and perfect timing exist, something that does not actually occur under real conditions. As prior knowledge of the exact timing of load growth, and perfect matching of additional resources to meet that additional growth, is not achievable under real world scenarios, the addition of IPP resources tends to occur in larger blocks of resource purchases than the model shows. These larger purchases ensure adequate competition but result in supply being added in larger groupings rather than in the small incremental additions that the model assumes.

The analysis evaluated the cost-effectiveness of the project by comparing the PV of the costs between portfolios with and without Site C over a 30-year analysis period (however, due to the lead time for Site C construction, Site C is only in commercial operations for the final 18 years of the evaluation period).

Table 8 shows the results of this PV comparison. Numbers shown represent the difference in PV cost between the portfolio considered and the Site C portfolio.

Table 8 Base Case Present Value of Cost Differential Compared to Site C Portfolio ($ millions, F2013 dollars)

Scenario	Clean Generation Portfolio	Clean + Thermal Portfolio	Clean + Thermal + DSM3
No LNG F24 Site C ISD	+630	+150	+330
Expected LNG Up to 700 MW Market Bridging F24 Site C ISD	+1,850	+1,260	No analysis
Expected LNG Up to 300 MW Market Bridging with Gas Peakers on North Coast F24 Site C ISD	+1,500	+890	No analysis

* Updated analysis reflecting changes made during the Provincial FID is available in Appendix K.

As shown, Site C is cost-effective when compared to other resource options. Site C has a cost advantage at its earliest ISD in a conservative case with no load from new LNG facilities. Site C's cost advantage increases with in the case of expected LNG. In addition, Table 8 shows Site C retains a cost advantage in the case where it is compared to a portfolio including additional DSM (DSM Option 3) as well as Clean and Thermal resources.

Appendix E-1 provides further details on the results of the Portfolio Modelling.

4.4. Non-financial Considerations

Evaluation of non-financial considerations associated with Site C was undertaken through the use of Block Analysis, which compares portfolios of resources that make up the same 5,100 GWh of energy and 1,100 MW of dependable capacity as Site C. The resources selected as part of the Block Analysis were based on the resources selected in the Portfolio Modelling results discussed in Section 4.3.

The Block Analysis approach was used to provide an appropriate project-specific comparison of environmental and economic development attributes. A discussion of the environmental and economic development attributes is provided below. Refer to Appendix F for a description of the resource blocks created as part of the Block Analysis and the financial, environmental, and economic development attributes of these portfolios.

4.4.1. Environmental Attributes

A comparison of environmental attributes is provided in Table 9.

Table 9 Summary of Environmental Attributes

		Clean Block	Clean + Thermal Block		Site C
			Rev 6 & 6 SCGTs	Rev 6, GMS & 4 SCGTs	
GHG Emissions* (*tonnes/yr, thousands*)		220	660	510	0
Local Air Emissions* (*tonnes/year, thousands*)	Sulphur Dioxide	0.1	0.1	0.1	0
	Oxides of Nitrogen (NOx)	0.3	0.6	0.5	0
	Carbon Monoxide (CO)	0	1.3	0.9	0
Land Footprint (*hectares*)		2,560	1,770	2,070	5,660
Freshwater Footprint (*stream length, kilometers*)		0	0	0	125
Reservoir Creation (hectares)		0	0	0	9,300

Note: GHG and local air emissions in the portfolio analysis are only shown for fuel combustion during operations.

The Site C portfolio would have significantly lower GHG and air contaminant emissions intensity than both sets of alternative portfolios. Site C life-cycle GHG emissions would be comparable to other clean renewable resources. The Clean portfolio included a municipal solid waste resource option that results in GHG emissions from fuel combustion. The Clean + Thermal portfolio has significantly higher levels of GHG emissions due to the combustion of natural gas.

The Site C portfolio could have a larger land and freshwater footprint due to the inundation required for reservoir creation. In addition, Site C's footprint is concentrated in a single area of the Peace region. Alternatives would result in a footprint that mainly consists of linear works such as transmission lines and roads across the province.

4.4.2. Economic Development Attributes

As shown in Table 10, the Site C portfolio results in higher GDP, tax revenues and jobs during the construction phase. During the operations phase, jobs and GDP would be lower.

Table 10 Comparison of Economic Development Attributes

	Clean Block	Clean + Thermal Block		Site C
		Rev 6 & 6 SCGTs	Rev 6, GMS & 4 SCGTs	
Provincial GDP during construction (*millions*)	2,500	1,600	1,700	3,700
Prov. Revenues during construction (*millions*)	360	230	240	520
Construction Jobs* (*total person-years*)	30,800	19,900	21,000	44,200
Operations Jobs (*jobs per year*)	1,000	985	960	75

Note: Construction of Site C would create approximately 10,000 direct person-years of employment during construction, and approximately 33,000 direct and indirect person-years of employment through all stages of development and construction. For the purposes of portfolio analysis, total job numbers for all resources include induced jobs, resulting in higher numbers for all portfolios.

Information about specific Site C benefits is available in Section 6.

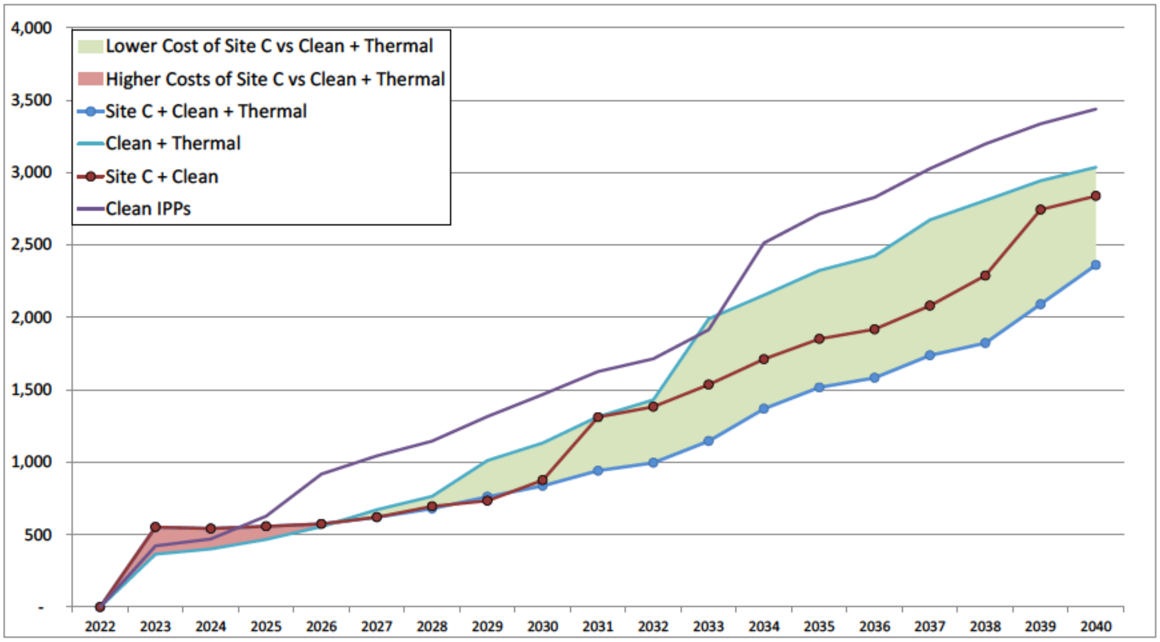
4.5. Ratepayer Impact / Cost of Service Analysis

In addition to the financial analysis discussed in Section 4.3, BC Hydro evaluated the expected ratepayer impacts of the portfolios. This analysis was based on the portfolios identified in the Portfolio Modelling analysis, but estimated the expected cost of service and rate impacts that would result.

The cost of service provides a proxy for the revenue requirements that would be required from BC Hydro customers to recover the costs of new resources. The main difference between the cost of service and the portfolio PV modelling described in Section 4.3 is the use of actual expected annual costs as compared to levelized annual costs. For further details on the Cost of Service analysis refer to Appendix G.

Figure 5 shows the comparison of the cost of service for the Site C portfolio compared to Clean + Thermal alternatives in the base case with LNG.

Figure 5 Cost of Service Comparison (nominal dollars)



* Updated analysis reflecting changes made in the Provincial FID is provided in Appendix K

As shown, the Site C portfolio will result in lower costs to BC Hydro customers over the long term, although there is an early 2-5 year period where the Site C portfolio is slightly higher cost than alternatives. The long-term savings to ratepayers average approximately [redacted] million per year in the period from 2030-2040, and would continue to grow for the remainder of Site C's project life.

In terms of rates, as shown in Figures 6 and 7, the profile is similar to the cost of service. There is a short-term increase in rates followed by lower rates with Site C for the remainder of the project life.

Figure 6 Comparative Ratepayer Impact – Clean Generation Portfolios Compared to Site C

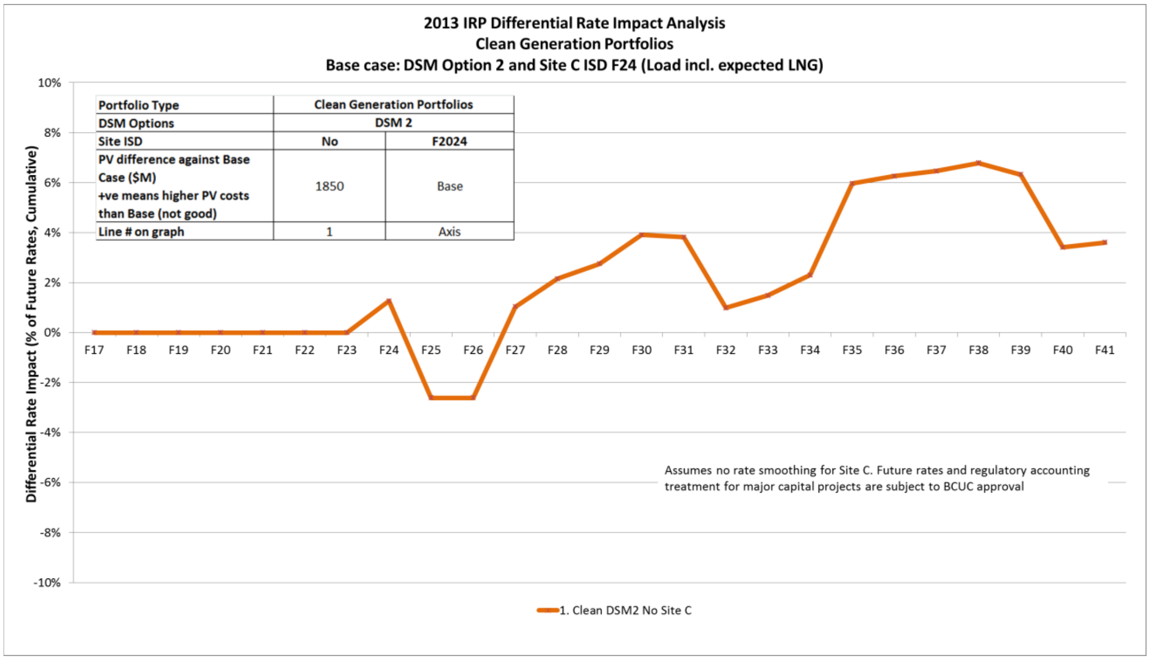
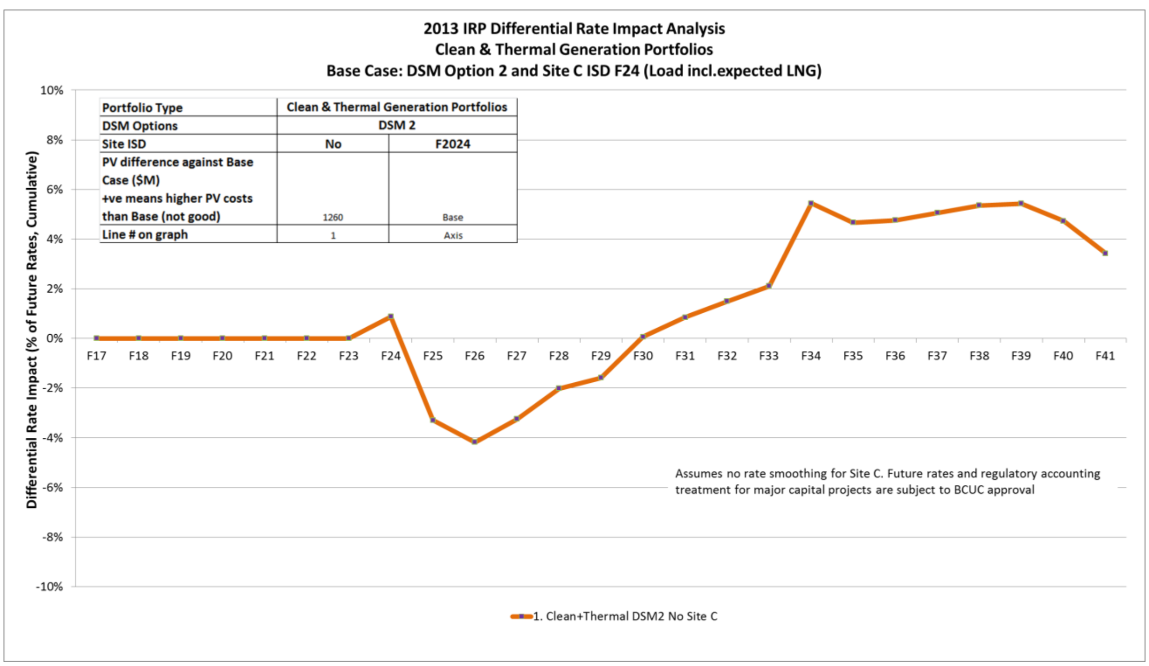


Figure 7 Comparative Ratepayer Impact – Clean + Thermal Portfolio Compared to Site C



4.6. Uncertainties and Risks

To test its findings against uncertainties in future conditions, BC Hydro conducted sensitivity analysis that compares the cost-effectiveness of Site C to alternative resources in a range of potential future scenarios.

- **Increases or decreases in the future gap between electricity supply and demand.** The size of the gap informs the timing of resource requirements and the level of short-term surplus created by Site C and the alternative resources as they come into service.
- **Increases or decreases in future market prices for electricity and natural gas.** Electricity market prices affect the value of the short-term surplus created by Site C and the alternative resources, while natural gas prices affect the cost of gas-fired generation. Electricity market prices may be driven by either underlying market dynamics, or by fluctuations in the US-Canadian exchange rate.
- **Decreases in the difference between the cost of capital for BC Hydro and the cost of capital for IPPs.** The cost of capital affects the cost of resources as it represents the financing costs for the projects.
- **Increases or decreases in the system costs of integrating intermittent wind resources.** As generation from wind resources can vary significantly on a daily, weekly, and monthly basis there are reserve requirements to integrate this generation into BC Hydro's electricity system while ensuring reliable supply. The cost of this integration affects the cost of wind resources.
- **Increases in the cost of construction for Site C.** Given the detailed cost estimate for Site C, a situation where there was a dramatic increase in the cost of construction (e.g., 30 per cent) is highly unlikely outside a scenario where there is a market disruption (e.g., an increase to labour costs or steel prices). Such a disruption would also be expected to affect the costs of other resource options such as IPP options, although possibly not to the same extent.
- **Delays to the in-service date of Site C.** There is a risk that the in-service date (**ISD**) of Site C would be delayed due to events prior to or during construction. As a result, BC Hydro tested scenarios with a F2026 ISD as well as the base case F2024 earliest ISD. This analysis calculated the PV benefits of such a scenario, but did not consider the cost and risk impacts of such as delay. Further discussion of the consequences of a delay to the project is available in Appendix I.

The sensitivity analysis determined that Site C is the preferred alternative in a wide range of future scenarios. The scenarios in which alternatives are preferred to Site C are generally low probability, and associated with low long-term economic growth or market prices and higher Site C construction costs. Further information is available in Appendix E-2.

In addition to the sensitivities discussed above, there are key uncertainties and risks not captured in the portfolio analysis:

- **Deliverability risk associated with DSM:** The portfolio modelling assumes that the current DSM target will deliver the expected energy and dependable capacity savings. There are significant delivery risks associated with the DSM target, particularly with respect to the reliance on 1,400 MW of dependable capacity by F2021. DSM requires customers to make behavioral changes that can be difficult to implement in a low-rate jurisdiction like B.C., which results in uncertainty whether the DSM target (or additional DSM such as DSM Option 3) will be achieved. In addition, recent evaluation results show that the commercial conservation rate structures are not delivering the expected amount of energy (and associated capacity) savings.
- **Uncertainty in resource characteristics:** The resource options used to populate the portfolios of alternative resources options are mostly based on "typical" projects with estimated costs, footprints, and other attributes. The actual characteristics of alternative projects would not be known until the projects were identified. This uncertainty does not apply to Site C, Revelstoke 6, or GMS Units 1-5 as these are projects with known locations and with significant investigative works undertaken to date. This is particularly notable in the area of cost estimates – as described in Section 2.2, the Site C cost estimate is a Class 3 degree of accuracy, where the alternative projects provide only an average estimate for such projects and are based on Class 4 or Class 5 (less developed) cost estimates.
- **IPP attrition risk / IPP Flexibility:** The portfolio modelling does not reflect the relatively high IPP attrition rate that BC Hydro has observed through its power acquisition processes. In order to reflect this attrition rate, BC Hydro would likely have to award EPAs representing more energy than would be expected to be required with resulting uncertainty in the amount of energy entering service. In addition, as described in section 4.3, a main drawback of the portfolio modeling approach is that there is an inherent assumption that perfect foresight and perfect timing exist and thus overstates IPP flexibility. BC Hydro structured its acquisition processes to attract larger sized IPP resources and achieve high levels of competition. These larger calls will not be able to match load growth as closely as assumed by portfolio modelling. In addition, long-term 'take-or-pay' EPAs for intermittent IPPs limit the ability ramp down volumes as recent experience has shown. Reality is that CEBC and IPPs lobby for regular calls in advance of need and use economic development as a rationale, and this can (and has) lead to surpluses of energy.
- **Uncertainty in IPP costs at termination of EPAs:** EPAs with IPPs for available resources have varying durations that are shorter, ranging from 15 to 40 years. At the end of EPA terms, there is significant supply and price risk to BC Hydro because there is no assurance 1) that the available IPPs will continue operations past the expiry of EPAs, 2) that IPPs will contract with BC Hydro if they do continue to operate, or 3) that IPPs will contract at a price comparable to their current real-dollar prices. In terms of effects on ratepayers, IPP prices also tend to rise with inflation, increasing the nominal costs of service; this contrasts with the cost profile of Site C, where the impact of the amortization of costs across time tends to erode due to the effects of inflation.

4.7. Conclusions of Analysis of Alternatives

Table 11 combines the Block and Portfolio Analysis and summarizes key attributes used to compare Site C to alternative portfolios, with colours indicating whether the Site C portfolio had better or worse performance on these key attributes.

Table 11 Summary of Analysis of Alternatives

(Green = Site C advantage, Red = Alternatives advantage, Yellow = No clear advantage).

Attribute	Units	Clean Generation		Clean + Thermal Generation		Site C Portfolio	
Financial Attributes							
PV Differential – No LNG	$F2013 million	[redacted]		[redacted]		Base Case	
PV Differential – Expected LNG (market bridging)	$F2013 million	[redacted]		[redacted]		Base Case	
PV Differential – Expected LNG (thermal bridging)	$F2013 million	[redacted]		[redacted]		Base Case	
Environmental Attributes							
Land footprint	Hectares	2,560		2,070		5,660	
Affected stream length	Kilometres	0		0		125	
Reservoir created (Includes existing river in ha)	Hectares	0		0		9,300	
GHG emissions	Tonnes/year, thousands	220		510		0	
Local Air Emissions	Tonnes/year, thousands	NOx	CO	NOx	CO	NOx	CO
		0.3	0	0.5	0.9	0	0
Economic Development Attributes							
Construction jobs	Total Jobs	30,800		21,000		44,200	
Construction GDP	$F2013, million	[redacted]		[redacted]		3,700	
Operations jobs	Jobs per Year	1,000		960		75	

Note: Environmental and Economic Development Attributes for Clean + Thermal Portfolio based on Block #2 with Revelstoke 6, GMS Units 1-5, and 4 SCGTs.

Compared to both the Clean portfolio and the Clean + Thermal portfolio, the Site C portfolio had the following results:

- Superior financial attributes, with a lower PV and portfolio UEC than alternatives

- Mixed economic development attributes, with a larger number of construction jobs created and higher construction GDP but lower operations jobs
- Mixed land footprint, with a larger land and stream footprint but with the majority of the footprint representing a conversion of habitat from terrestrial and river environments to a productive reservoir environment rather than a facility footprint
- Superior GHG and air emissions, with slightly lower GHG and local air emissions (CO, NOx)

The Site C portfolio is preferred under financial and the construction-period economic development attributes, as well as key environmental attributes, particularly GHG and local air emissions. As the Site C portfolio is preferred in nearly all attributes there was no requirement to undertake a quantitative weighting exercise; for any of the alternatives to have been selected as the preferred alternative, the value assigned to the land and stream footprint would have had to have greatly outweighed the value assigned to any financial, economic development or air emission considerations.

Additional analysis on the comparison of Site C to alternatives was performed in support of the Provincial FID and is provided in Appendix K. This analysis confirms that Site C is a preferred resource option given the changes proposed in the Provincial FID.

There would be a number of additional, specific benefits associated with Site C, including trades training initiatives, legacy benefits for Peace region communities, recreation opportunities, and mitigation measures such as support for housing, daycare and local infrastructure. These benefits are known due to the advanced stage of the project, but were not included in the portfolio analysis due to the lack of comparable information for the potential alternatives included in portfolios. Please refer to Section 6 for a description of these benefits.

Based on the sensitivity analysis conducted, Site C would remain a preferred resource option under the majority of potential future scenarios. The potential for regret associated with proceeding with the project is primarily associated with a scenario where there is long-term load growth lower than has been seen in BC's history that would persist for the planning period (i.e., long-term economic stagnation and no LNG load). In such a case load growth would be minimal, and the need for a new resource the size of Site C would be limited. It should be noted that such a case is very low probability, as it would require an extended period of substantially lower load growth than seen in B.C.'s history.

The Need for and Alternatives to the Project has been a common theme as part of BC Hydro's consultations with First Nations, the public and stakeholders. Appendix J provides discussion of some of the comments received during the consultation process and BC Hydro's consideration of these comments. Appendix J also reflects consultation on Need and Alternatives with T8TA in late summer and early fall of 2014.

Based on the analysis of alternative resource options, and considering the adjustments made in the Provincial FID (discussed in Appendix K) Site C provides the best combination of financial, technical, environmental, and economic development attributes and is therefore the preferred option to meet the need for energy and dependable capacity within BC Hydro's planning horizon. As a result, BC Hydro recommends building Site C to add 5,100 GWh of annual energy and 1,100 MW of dependable capacity to the system for its earliest ISD.

5. Analysis of Alternative Designs (Means Of Delivery)

In addition to the analysis of Site C compared to alternative resource options, BC Hydro also undertook analysis to determine the preferred means of delivering the project. This section describes the analysis the location and number of dams to deliver the hydroelectric potential associated with the flood reserve.

Additional analysis was conducted on alternatives with respect to the substation and transmission line, the realignment of Highway 29, the approach to quarried and excavated materials, the worker accommodation, and the access route to the south bank. The analysis of these alternatives was not material to the business case for Site C.

5.1. Alternates Considered – Location and Number of Dams

Between 2009 and 2011, Klohn Crippen Berger Ltd., SNC-Lavalin Inc., and Hatch Ltd. undertook a comprehensive study (the Alternates Study) to evaluate alternate means of developing the hydroelectric potential of the Site C Flood Reserve. The intent was to undertake a comprehensive review of all previously identified alternates and any new alternates and compare them to the project using a consistent evaluation process. The review does not consider partial options (for example, completing only one component of a multi-dam option) as a partial option would not fully meet the hydroelectric potential and would result in a high cost to generating capability ratio due to the large costs from design to mobilization for dam construction of any size (making only the construction of optimal designs prudent).

The historical design had the location of the Site C dam just downstream of the Moberly River, at a location known as Axis C3. The following alternatives were considered to the historical location:

- **Single-dam alternatives:** Alternatives with a single dam located upstream of the Moberly River. These alternatives would avoid effects on the Moberly River, but would not develop all of the available head between Peace Canyon Dam and Axis C3. Single-dam alternates considered were:
  - A dam located at Axis C1, 5.5 km upstream of Axis C3
  - A dam located at Axis C2, 3 km upstream of Axis C3
  - A dam located just downstream of Wilder Creek, 11.5 km upstream of Axis C3
- **Dam Cascades:** Alternatives with cascades of two or more dams lower in height than the proposed Site C dam. These alternatives would reduce the area of flooded land while maximizing development of all of the head between Peace Canyon Dam and Axis C3. Cascades of multiple dams considered were:
  - A two-dam cascade with a dam at Axis C3 and an additional dam located approximately 66 km upstream
  - A three-dam cascade with a dam at Axis C3 and two other low dams located approximately 22 km and 59 km upstream
  - A four-dam cascade with a low dam at Axis C3 and three other low dams located approximately 18 km, 39 km, and 61 km upstream

  - A seven-dam cascade with a dam at Axis C3 and six other dams located approximately 10 km, 23 km, 37 km, 53 km, 65 km, and 79 km upstream

- The eastern boundary of the Site C Flood Reserve is approximately 3.7 km downstream of Axis C3. Moving the dam further downstream of Axis C3 was not considered since the geological conditions are less favourable. This is because the elevation of the bedrock outcrop on the north bank of the river drops and the slopes above the bedrock comprise debris from slides and slumping of the overburden.

5.2. Analysis and Conclusions

Layouts, site characteristics, cost estimates, and energy generation estimates were developed for each of the alternatives described above. This information was used to compare the alternatives based on considerations in the following categories:

- Functionality, such as dam safety and reliability
- Engineering parameters, such as design risk and constructability
- Economic feasibility (whether the achievable UEC was in the same range as alternatives)
- Effects on the physical environment
- Effects on the biological environment
- Effects on the socio-economic environment

A multi-attribute decision making process was used to assess the six alternates relative to the project. The evaluation process consisted of:

- Identifying environmental effects and engineering functionality of each alternate relative to the project and one another
- Ranking and weighting the environmental effects and functionality of each alternate, and comparing these relative to the project and each other
- Comparing the relative footprint ratio and energy cost ratio of each alternate to the project

The relative footprint ratio was determined for each alternate relative to the project by weighting and combining the ratings for each of the four attributes, namely:

- Functionality
- Effects on the physical environment
- Effects on the biological environment
- Effects on the socio-economic environment

A preliminary analysis screened out four alternates as a result of a higher energy cost ratio due to higher project cost and lower energy production without providing a decrease in the relative footprint ratio. A series of sensitivity analyses were performed on the three remaining options, including Site C, to determine whether changing the various weightings would materially change their ranking.

The Alternates Study concluded that:

- There are no environmental factors that would eliminate an alternate
- The relative differences in environmental effects and functionality between alternates are small
- Alternate locations resulted in a significantly higher costs per unit of energy
- The small relative differences in benefits between the alternates do not justify the greater costs
- There is no benefit to partial options.

The Alternates Study demonstrates that the project is the preferred means delivering Site C.

6. Project Benefits

This section describes the benefits associated with Site C.

6.1. Ratepayer Benefits

Site C would be a cost-effective clean, renewable and reliable power resource that would provide long-term energy, capacity and other system benefits to the provincial power grid. Benefits to ratepayers include:

- **Cost-Effective Electricity Supply**
  - Site C will result in lower rates for BC Hydro's customers over the long-term. While the project will create an approximately three per cent cumulative rate increase for the first few years compared to alternative portfolios, rates would then be lower for remainder of the 70-year project life.
- **Firm Energy**
  - Site C would provide an average of 5,100 GWh of energy every year. Over 90 per cent of this average energy is firm energy, available to serve BC Hydro customers even in the driest historical weather conditions.
- **Dependable Capacity**
  - Site C would add 1,100 MW of dependable generation capacity to the BC Hydro system. Dependable capacity is the maximum amount of power that can be reliably supplied to meet peak instantaneous demand (e.g., the dinner hour on the coldest day of the year).
- **Flexibility**
  - Due to the ability to store water in a reservoir, power produced from large hydroelectric resources like Site C can typically be adjusted to meet the needs of the overall power grid, such as the fluctuations in the system load, or to back up varying levels of energy supplied by intermittent resources (e.g., wind).

6.2. Economic Development Benefits

The construction of Site C would create jobs, provide a boost to provincial GDP and increase revenues for all levels of government.

- **Employment**
  - Construction of Site C would create approximately 10,000 person-years of direct employment during construction, and approximately 33,000 person-years of total employment through all stages of development and construction.
  - The Site C project would provide 25 permanent direct jobs during operations. Additional employment would result from sustaining investments in the project

such as refurbishment and/or replacement of project components over the life of the project, resulting in an average of 160 total jobs per year during operations.

- **Economic Activity**
    - Building Site C would contribute [redacted] to provincial GDP from the purchase of goods and services during construction, including approximately [redacted] to regional GDP.
- **Government Revenues**
    - During construction, Site C would result in a total of [redacted] in tax revenues to local governments and, once in operation, [redacted] in annual revenues from grants-in-lieu and school taxes. These revenues are in addition to a legacy benefits agreement that would provide regional communities with [redacted] per year for 70 years (see Section 6.4).
    - Activities during construction would result in approximately [redacted] in provincial revenues, and approximately [redacted] for the federal government.
    - The Province would receive annual water rentals amounting to over [redacted] per year.

6.3. Environmental Benefits

As the third project on the Peace River, Site C would optimize BC Hydro's existing resources, produce among the lowest GHG emissions, per gigawatt hour, and help integrate intermittent renewables into the provincial power grid.

- **Optimizing Existing Resources**
    - The Site C reservoir would be comparatively small in relation to generating capacity than some of BC Hydro's other major hydroelectric facilities, and would operate within a smaller range of water levels. This is because it would rely on the existing Williston Reservoir for water storage, enabling Site C to generate approximately 35 per cent of the energy produced at the W.A.C. Bennett Dam, with only five per cent of the reservoir area.
- **Low Greenhouse Gas Emissions**
    - Site C would produce among the lowest GHG emissions, per gigawatt hour, when compared to other forms of electricity generation, significantly less than fossil fuel sources, and within the ranges expected for wind, geothermal and solar sources.
- **Integration of Intermittent Renewables**
    - The flexibility and dependability of the power produced by Site C would facilitate the integration of intermittent energy resources, such as wind and run-of-river hydro, into the provincial power grid. For example, since wind turbines do not produce energy when the wind is not blowing, Site C would be able to quickly increase or decrease generation to match the output of wind resources. Refer to Appendix H for details.

6.4. Community Benefits

Among the benefits to local communities from the Site C project are a regional legacy benefits agreement, infrastructure improvements, recreation and tourism opportunities, and affordable housing.

- **Regional Legacy Benefits**
  - A regional legacy benefits agreement between BC Hydro and the Peace River Regional District (PRRD) would provide [redacted] annually to the PRRD and its member communities for a period of 70 years, starting when Site C is operational. The annual funding would be indexed to inflation.
  - These funds would be in addition to local revenues from construction and mitigation measures for the project.
- **Improved Infrastructure**
  - Roads and highways would be upgraded and enhanced during the construction phase, and this would support long-term economic development in the region.
  - 85th Avenue Industrial Lands would be improved after BC Hydro's use by being graded for future industrial land use.
- **Recreation and Tourism Opportunities**
  - Construction and operation of Site C would provide new and expanded recreation and tourism opportunities for residents of the Peace Region, including new boat launches and day-use areas, public viewpoints of the dam site and funding for community recreation sites.
  - Fishing opportunities during operations would also be expected to increase as the Site C reservoir would support increased boating and angling use, and would continue to support sport fishing.
- **Affordable Housing**
  - To encourage workers to live locally, BC Hydro is working with BC Housing to plan and build approximately 40 new housing units for use by BC Hydro's workforce and their families during construction, plus 10 new affordable housing units.
  - After construction, all of the housing units would be available as affordable housing in the community.
- **Skills Training**
  - BC Hydro has made investments in skills training aimed at increasing skilled labour capacity in the region, including:
    - $1 million to Northern Lights College Foundation to support trades and skills training through the creation of student bursaries.
    - $184,000 in funding to Northern Opportunities for the creation of a school district career counsellor position to encourage students to stay in school and facilitate a transition into trades and career training.

- $100,000 in funding to the North East Native Advancing Society to support trades training under its North East Aboriginal Trades Training program.
- A five-year funding agreement of [redacted]0 with Northern Opportunities for its pre-apprenticeship program.

6.5. Benefits for Aboriginal Groups

Aboriginal groups are expected to see economic and social development benefits through Impact Benefit Agreements negotiated with BC Hydro, which may consist of:

- Lump sum cash payments or payment streams over time
- Work and contract opportunities, including potential directed procurement
- Crown land transfers
- Implementation of land protection measures or special land management designations

BC Hydro is committed to Aboriginal inclusion in procurement and employment opportunities related to the construction of the Site C project. BC Hydro's Aboriginal Contracting and Procurement Policy is designed to increase the involvement of Aboriginal groups in economic opportunities associated with BC Hydro's business activities. Procurement practices under this policy include:

- **Capacity-Building Initiatives**: Initiatives are being implemented to provide funding or resources in order to provide training, improve skills or increase business capacity. Capacity-building initiatives related to Site C are described in more detail below.

- **Directed Aboriginal Procurement**: Initiatives could include direct awards, select tendering, set-asides, and the breaking up of large contracts.

- **Aboriginal Evaluation Criteria**: The use of Aboriginal evaluation criteria in procurement packages will provide an incentive for contractors to establish working relationships and increase Aboriginal participation in construction contracts.

- **Aboriginal Business Directory**: BC Hydro's Aboriginal Business Directory is accessible to suppliers and contractors, and enables BC Hydro to promote partnerships between non-Aboriginal and Aboriginal businesses in contract work for BC Hydro.

In addition, BC Hydro is hosting business-to-business networking sessions to provide opportunities for regional and Aboriginal businesses and contractors to introduce their company, its services and experience to teams that have been shortlisted for major Site C contracts.

BC Hydro is also working with Aboriginal community groups, contractors, employers, educational institutions and other organizations to advance initiatives to secure a supply of qualified local workers.

For example, BC Hydro has provided [redacted] to support trades and skills training at Northern Lights College, 50 per cent of which is dedicated to Aboriginal students. In addition, BC Hydro is working to promote job opportunities within the local community, including working with construction contractors to facilitate local and Aboriginal hiring.

6.6. Alignment with Provincial Government Objectives

Site C aligns with several objectives established by Provincial Legislation. Table 12 below shows how Site C will align with provincial objectives under the *Clean Energy Act*.

Table 12 Project Alignment with *Clean Energy Act* Objectives

Clean Energy Act Objective	How the Project Supports the Objective
At least 93 per cent generation from clean or renewable resources	The project is a clean or renewable resource as defined by Section 1 of the *Clean Energy Act*. The project provides clean or renewable energy and dependable capacity, and also has the ability to shape, firm, and help integrate intermittent clean or renewable resources such as wind and run-of-river.
To ensure that BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America	The project is a cost-effective resource for energy and capacity compared to alternative supply options.
To reduce GHG emissions	As a hydroelectric resource, the project emits virtually no GHG emissions when compared to natural gas-fired electricity resources, and on a per GWh basis, emits a similar amount of GHGs as other clean or renewable resources such as wind.
To encourage economic development and the creation and retention of jobs	The project is a job-intensive capital project that will create employment in B.C. during the construction period.
To maximize the value of B.C.'s generation and transmission assets	The project provides additional benefits (e.g., shaping and firming benefits) to optimize the value of B.C.'s generation and transmission assets. In addition, as the third project on one river system, the project would generate 35 per cent of the energy produced at the W.A.C. Bennett Dam, with 5 per cent of the reservoir area.

7. Supporting Documentation

7.1. Appendices

A Legislative and Policy Context
B Load-Resource Balance
C DSM Jurisdictional Review
D Market Price Scenarios
E Portfolio PV Modelling Details
  E-1 Portfolio Modelling
  E-2 Sensitivity Analysis
F Block Analysis
G Cost of Service Analysis
H Dispatchable Capacity
I Delay Discussion and Analysis
  I-1 Consequences of Project Delay or Halt
  I-2 Economic Analysis of Project Delay
J Consideration of Comments Received on Need and Alternatives
K Additional Analysis in Support of Provincial Investment Decision

7.2. Supporting References

2013 IRP Materials

- December 2012 Load Forecast
- 2013 Integrated Resource Plan

Environmental Assessment Materials

- Project Description Report
- Environmental Impact Statement (as amended)
- Information Requests & Undertakings
- Hearing Transcripts
- Final Argument of BC Hydro
- Report of the Joint Review Panel

APPENDIX A – LEGISLATIVE AND POLICY CONTEXT

There are several pieces of legislation and policy that are fundamental considerations of the need for Site C and the analysis of alternatives. This section provides an overview of some key pieces of the legislative and policy framework. Each policy detailed remains in effect (for example, the 2002 Energy Plan is not superseded by the Clean Energy Act) except where specifically noted, so it is the combination that creates the full legislative and policy framework.

1. Utilities Commission Act

Under the Utilities Commission Act, BC Hydro has a legal obligation to serve its customers. This includes planning to meet both the energy and capacity requirements of its residential, commercial and industrial customers.

2. 2002 Energy Plan

Policy Action No. 13 provides that IPPs will develop new generation, with BC Hydro limited to undertaking efficiency improvements at its existing facilities and Site C.

3. Clean Energy Act

Section 2 of the *Clean Energy Act* sets out B.C. Government objectives, referred to as "British Columbia's energy objectives", that BC Hydro must respond to and that the BCUC must consider and be guided by in various applications. The objectives applicable to the consideration of Site C are:

- to achieve electricity self-sufficiency;
- to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;
- to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
- to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;
- to reduce BC greenhouse gas emissions
- to encourage economic development and the creation and retention of jobs;
- to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;
- to achieve British Columbia's energy objectives without the use of nuclear power;

The self-sufficiency requirement outlined above is further described in Section 6 of the *Clean Energy Act*, and requires BC Hydro to achieve electricity self-sufficiency by the year 2016 (i.e., F2017) by holding the rights to an amount of electricity that meets its electricity supply obligations, taking into account DSM and electricity "solely from electricity generating facilities within the Province". The B.C. *Electricity Self-Sufficiency Regulation* (B.C. Reg. 315/2010) enacted under the *Clean Energy Act* prescribes the mid-load forecast as the forecast to be used for the purpose of determining the self-sufficiency requirement

4. 2007 Energy Plan

The 2007 Energy Plan sets the policy framework in which BC Hydro develops resources. The 2007 Energy Plan stresses the development of clean or renewable resources. While a number of 2007 Energy Plan Policy Actions have been overtaken by Section 2 of the Clean Energy Act (see below), there are 2007 Energy Plan Policy Actions relevant to the review of Site C and potential alternatives to the Project.

- All new electricity generation projects will have zero net GHG emissions
- Require zero GHG emissions from any coal thermal electricity facilities
- No nuclear power

APPENDIX B – LOAD RESOURCE BALANCE

This Appendix provides supporting information related to the Load-Resource Balance (LRB) underlying the need for Site C. The values for energy and peak capacity supply and demand are sourced from the 2012 Load Forecast, which formed the basis of the Site C application as a component of the Environmental Impact Statement and Evidentiary Update, and were presented in the Joint Review Panel Hearings.

The LRB tables are presented for the period from F2017 to F2033. The years F2014-F2016 are part of BC Hydro's current operational horizon and are not part of the long-term planning period. LRB gaps during the operational horizon are managed through reliance on existing resources given near-term market conditions, system constraints, planned outages and inflows. Note that the LRBs presented here do not include:

- Adjustments to the planned Standing Offer Program as recommended in the 2013 IRP. This adjustment is approximately 450 GWh/yr in F2024 and does not materially affect the Portfolio Analysis.
- Changes to the LRB resulting from changes to the Load Forecast and expected IPP volumes. The 2014 energy LRB surplus in the first five years of the Project is reduced by an average of about 290 GWh; these reductions are offset by increases in the surplus of about 240 GWh in the second five year period. As a result there is not expected to be a material change to the Portfolio Analysis based on this change.

1. Energy and Capacity Capability for Existing and Committed Supply

Using F2022 as the reference year, Table 1 and Table 2 show BC Hydro's projected capability to provide energy and dependable capacity, respectively, using existing heritage assets and existing and committed supply from Independent Power Producers.

Table 1 Energy Capability for Existing and Committed Supply

Gigawatt Hours (GWh)		F2022
Heritage hydroelectric	(a)	48,500
Heritage thermal (Prince Rupert)	(b)	200
Existing and committed IPP supply	(c)	15,000
Total supply	**(d) = a + b + c**	63,700

Table 2 Dependable Capacity for Existing and Committed Supply

Megawatts (MW)		F2022
Heritage hydroelectric	(a)	11,400
Heritage thermal (Prince Rupert)	(b)	50
Existing and committed IPP supply	(c)	1,200
Reserves[a]		
Supply requiring reserves	(d) = a + b + c	12,700
14% of supply requiring reserves	(e) = d * 0.14	1,800
Supply not requiring reserves		
Alcan 2007 EPA	(f)	150
Total supply	**(g) = d – e + f**	11,050

NOTE:

[a] System generating capacity beyond that required to meet peak demand, ensuring sufficient generation is available if some generating units are not available; necessary to meet reliability criteria for planning and operation.

2. Energy and Capacity LRBs before DSM Target

Table 3 presents the projected energy and capacity surpluses or deficits in meeting projected demand with the existing and committed supply. The assumptions for demand are based on the mid-range forecast, prior to any future Demand Side Management (DSM) initiatives, and assume no load from Liquefied Natural Gas (LNG) consumers. Bracketed numbers indicate a surplus, while un-bracketed numbers indicate an LRB gap in meeting demand. Table 3 shows a need for additional energy resources commencing in F2018 and a need for additional capacity resources commencing in F2017.

Table 3 Energy and Capacity Deficit/(Surplus) without DSM (No LNG)

Year	Energy (GWh)	Capacity (MW)
F2017	(700)	600
F2018	1,200	850
F2019	3,100	1,100
F2020	4,500	1,300
F2021	5,600	1,450
F2022	6,400	1,650
F2023	7,300	1,850
F2024	8,300	2,000
F2025	8,900	2,150
F2026	9,300	2,300
F2027	10,000	2,500
F2028	11,100	2,700

Year	Energy (GWh)	Capacity (MW)
F2029	12,000	2,950
F2030	13,100	3,150
F2031	14,100	3,400
F2032	15,100	3,600
F2033	15,900	3,800

3. Energy and Capacity LRBs with DSM Target

Table 4 demonstrates the effects of adding DSM initiatives to reduce demand and compares the results to the existing and committed supply for energy and dependable capacity. The table retains the assumption of no load demand from LNG customers.

Without future additional resources or load from LNG there is a need for new energy in F2027 and a need for new capacity in F2019.

Table 4 Energy and Capacity Deficit/(Surplus) with DSM (No LNG)

Year	Energy (GWh)	Capacity (MW)
F2017	(5,000)	(250)
F2018	(3,700)	(100)
F2019	(2,800)	-
F2020	(2,400)	100
F2021	(2,200)	100
F2022	(1,800)	150
F2023	(1,100)	300
F2024	(700)	400
F2025	(300)	500
F2026	(300)	550
F2027	200	700
F2028	900	850
F2029	1,800	1,000
F2030	2,600	1,150
F2031	3,300	1,350
F2032	4,200	1,550
F2033	4,900	1,750

4. Potential LNG load

Currently there are 12 publicly-announced LNG projects for Kitimat, Prince Rupert and other areas of the B.C. North Coast, Howe Sound in the Lower Mainland and Campbell River on Vancouver Island. Potential LNG load consists of: (1) compression load, which is the energy required by the main liquefaction compressors that cool natural gas into liquid form and represents the majority of LNG facility requirements; and (2) non-compression load, which refers to the rest of LNG facility power demand including other compressors, pumps, control systems, loading terminal equipment, lighting and office requirements. Non-compression load typically accounts for about 15 per cent of overall LNG facility energy requirements. In addition to the status of regulatory approvals, important LNG project decision-making steps that will inform BC Hydro's plans are the status of front-end engineering design and feasibility studies and final investment decisions.

After discussions with LNG proponents and review of LNG project descriptions submitted to the B.C. and Canadian environment assessment agencies, BC Hydro understands that proponents of the larger LNG projects generally will not be requesting electricity service for compression loads. Larger scale LNG proponents may request service from BC Hydro for non-compression load,[1] while smaller scale LNG projects such as the Woodfibre LNG project proposed for an industrial site near Squamish, B.C. may take service for both compression and non-compression load. For purposes of the EIS, BC Hydro set out a range of potential non-compression load of about 800 GWh/year to 6,600 GWh/year of additional energy demand, with an expected LNG load of 3,000 GWh/year. This corresponds to a range of 100 MW to 800 MW of additional peak demand.

[1] See, for example, Project Description (section 5.9) for LNG Canada dated March 21, 2013: "Each LNG liquefaction train will utilize natural gas-fired direct drive for the main refrigeration compressors to produce LNG. The LNG facility and marine terminal will require electrical power to operate all other supporting facilities and infrastructure. Approximately 90 MW of electrical power will be required for Phase 1 and approximately 150 MW will be required at full build-out. There are currently two options being considered for the electrical power requirements including: power supply option 1 – electrical power sourced from the BC Hydro electrical grid; and power supply option 2 – new electrical generation installed at the LNG facility site".

5. Energy and Capacity LRBs with DSM Target and LNG Load

Table 5 indicates that starting with the previous assumptions presented in Table 4, and then introducing amounts for LNG load, there will be a need for new energy resources in F2024 with low LNG demand, and in F2021 with high LNG demand. Table 6 indicates there is a need for new dependable capacity resources in F2019 under both LNG demand scenarios.

Table 5 Energy Deficit/(Surplus) with DSM and LNG (GWh)

Year	LRB with DSM and Low LNG	LRB with DSM and High LNG
F2017	(5,000)	(5,000)
F2018	(3,700)	(3,700)
F2019	(2,800)	(2,800)
F2020	(1,500)	(400)
F2021	(1,400)	1,800
F2022	(1,000)	4,800
F2023	(300)	5,500
F2024	100	5,900
F2025	600	6,300
F2026	500	6,300
F2027	1,000	6,700
F2028	1,700	7,500
F2029	2,600	8,400
F2030	3,400	9,200
F2031	4,100	9,900
F2032	5,000	10,800
F2033	5,700	11,500

Table 6 Capacity Deficit/(Surplus) with DSM and LNG (MW)

Year	LRB with DSM and Low LNG	LRB with DSM and High LNG
F2017	(250)	(250)
F2018	(100)	(100)
F2019	-	-
F2020	200	300
F2021	200	600
F2022	250	950
F2023	400	1,100
F2024	500	1,200
F2025	600	1,300
F2026	650	1,350
F2027	800	1,500

Year	LRB with DSM and Low LNG	LRB with DSM and High LNG
F2028	950	1,650
F2029	1,100	1,800
F2030	1,250	1,950
F2031	1,450	2,150
F2032	1,650	2,350
F2033	1,850	2,550

6. Energy and Capacity LRBs including Site C

Table 7 shows that with the addition of Site C to BC Hydro's existing and committed resources, BC Hydro would be able to meet the updated energy requirements shown in Table 4 for the duration of the planning horizon, and the capacity requirements until F2029 under the scenario with no LNG.

Table 7 Energy and Capacity Deficit/(Surplus) with DSM and Site C (GWh) (No LNG)

Year	Energy (GWh) LRB with DSM & Site C	Capacity (MW) LRB with DSM & Site C
F2017	(5,000)	(250)
F2018	(3,700)	(100)
F2019	(2,800)	-
F2020	(2,400)	100
F2021	(2,200)	100
F2022	(1,800)	150
F2023	(1,500)	300
F2024	(5,100)	(550)
F2025	(5,400)	(450)
F2026	(5,400)	(350)
F2027	(4,900)	(250)
F2028	(4,200)	(100)
F2029	(3,300)	50
F2030	(2,500)	250
F2031	(1,800)	400
F2032	(900)	600
F2033	(200)	800

APPENDIX C – DEMAND SIDE MANAGEMENT JURISDICTIONAL REVIEW

Demand-side management (DSM) is BC Hydro's first and largest option to meet electricity demand, and BC Hydro plans to meet 78 per cent of its load growth through these conservation and efficiency initiatives.

To evaluate how BC Hydro's DSM targets compare to those of its peers, BC Hydro has undertaken a review of DSM programs in other jurisdictions. This review shows that although the DSM target appears to be in line with more aggressive utilities, there are differences in DSM energy savings targets across jurisdictions which make precise comparisons challenging.

1. Jurisdictional Review

BC Hydro looked externally to determine whether other leading jurisdictions – as measured by DSM spending as a per cent of retail sales – have claimed to deliver on similar levels of DSM savings as BC Hydro, or are planning to deliver on similar savings levels in the future.
It is difficult to compare DSM energy savings targets across jurisdictions due to large variations in electricity prices (this is particularly the case for California utilities which are often referred to as DSM leaders; for example, Pacific Gas & Electric's San Francisco residential monthly bill is CDN $141 for 625 kWh compared to BC Hydro's Vancouver residential monthly bill of CDN $50 for 625 kWh.[1] Massachusetts and Vermont are also high electricity price jurisdictions), climate and customer mix; different time frames, political environments and legislative requirements; and the number of DSM tools employed and reported on. For example, BC Hydro uses three main tools to achieve its DSM targets (codes and standards, rate structures, and conservation programs).

The DSM jurisdictional assessment was compiled by the Cadmus Group (Cadmus Report, June 2011) and is summarized here, supplemented by a review of evidence submitted by the B.C. Sustainable Energy Association and the Sierra Club of B.C. as part of the F2012 to F2014 Revenue Requirements Application (referred to as the BCSEA Evidence).

Common to both the Cadmus Report and the BCSEA Evidence was a lack of data for the mid to long-term; consequently both sources focus on the period to 2015. In addition, both sources use saving ratios (GWh savings/GWh sold, the per cent of sales) as opposed to per cent of load growth as the metric with which to compare jurisdictions. This is because per cent of sales is the industry standard and the most commonly available metric.

The experiences in other leading jurisdictions are summarized in two ways:

- First, by looking at levels of savings claimed in other jurisdictions;
- Second, by looking at future savings targets from other jurisdictions.

[1] As of April 1 2013; source - BC Hydro Electricity Rate Comparison Report No. 6, submitted to the Minister of Energy and Mines and Minister Responsible for Core Review on 5 December 2013, Table 1, page 4.

2. Comparing Past Savings

The Cadmus Report looked at 26 utilities and DSM implementers based in North America. This sample comprises a snapshot of the North American electricity sector from industry leaders, large utilities and jurisdictions of interest to BC Hydro. However, as few jurisdictions report on energy savings from codes and standards and rate structures, the comparison is much less useful for changes to codes and standards and is of no use with respect to rate design experience.

Table 1 lists the 23 organizations which report on programs and compares their recent stated energy savings achievements. The BC Hydro average percentage represents program savings only, as savings from conservation rates and codes and standards became established after this timeframe.

The table shows that, from years 2005 to 2009, only a small number of the top DSM leaders in North America claim savings above 1% of sales. However, as noted above, these jurisdictions (Massachusetts, Vermont and Connecticut) have higher rates, which create a greater incentive for DSM behavioural changes.

Table 1: Average Annual Energy Savings from DSM Programs as Per Cent of Retail Sales *(2005 to 2009)*

Organization *(625kWh Average Residential Rate)*	**Average** *(%)*
1. Massachusetts Electric Co *(16.5¢/kWh)*	1.60
2. Vermont *(16.2¢/kWh)*	1.60
3. Connecticut Light & Power Co *(9.2¢/kWh)*	1.40
4. Puget Sound Energy Inc. *(8.6¢/kWh)*	1.10
5. Nevada Power Co *(No comparable rate available)*	1.00
6. BC Hydro *(8.9¢/kWh)*	**1.00**
7. Interstate Power and Light Co	0.90
8. Energy Trust of Oregon	0.90
9. Wisconsin Electric Power Co	0.80
10. MidAmerican Energy Co	0.80
11. Idaho Power Co	0.70
12. Arizona Public Service Co	0.70
13. Manitoba Hydro	0.70
14. Wisconsin Power & Light Co	0.60
15. PacifiCorp	0.50
16. Hydro Quebec	0.50
17. New Jersey Clean Energy	0.40

Table 1: Average Annual Energy Savings from DSM Programs as Per Cent of Retail Sales *(2005 to 2009)*	
Organization *(625kWh Average Residential Rate)*	**Average** *(%)*
18. Public Service Co of Colorado	0.40
19. New York State Research and Development Authority	0.30
20. Kansas City Power & Light Co	0.20
21. Consolidated Edison Co-NY Inc	0.20
22. Florida Power & Light Co	0.20
23. Ontario Power Authority	0.20
Average Excluding BC Hydro	**0.85**

NOTE: ^ Includes Codes and Standards.

To put Table 1 in context, the BCSEA Evidence provides that in 2006 and 2007, for public utilities that did report savings, the U.S. average was 0.35% of sales, with values ranging from 0.01% for four jurisdictions (Arkansas, Alabama, Mississippi and Missouri) to up to 2% (Hawaii and Vermont). No public utility has demonstrated it can sustain 2% for the mid to long term.

Drawing additional inferences from Table 1 must be done with some caveats:

- Verification methods and reporting vary amongst jurisdictions. Savings levels claimed in other jurisdictions may not necessarily translate into potential to reduce BC Hydro load given differences in verification methods, load composition, and opportunities for saving;
- Finding jurisdictions that reported using a combination of programs, codes and standards, and rates to meet DSM targets was not possible. Three California utilities include programs, and changes to codes and standards in their reported DSM savings and thus have not been included in Table 1 because the inclusion of codes and standards does not permit and 'apples-to-apples' comparison. The California utilities are: San Diego Gas & Electric (2% with both programs and some codes and standards), Pacific Gas & Electric Co. (2%) and Southern California Edison Co. (1.7%). As a result, Table 1 provides insight into the comparison of DSM program levels, but does not provide insight into benchmarking BC Hydro's combination of its three DSM tools to achieve DSM savings.

3. Comparing Forecast Savings Targets

The report found few other utilities with long-term planning horizons comparable to the 2013 Integrated Resource Plan. It looked at planned levels of energy savings for 2010 to 2015 for states that have Energy Efficiency Resource Standards and compared these to BC Hydro's DSM plans.

Similarly, the BCSEA Evidence only provided planned energy efficiency portfolio savings beyond 2015 for Vermont and what is called the 'Pacific Northwest': Vermont plans on achieving about 2% of sales from 2016 to 2021. As such, there is little jurisdictional evidence against which to benchmark BC Hydro's DSM long-term savings targets.

4. Conclusion of Jurisdictional Assessment

From what has been claimed by other jurisdictions, the following observations can be made:

- Almost no evidence was available from the jurisdictional assessments to help benchmark BC Hydro's longer-term (F2021) conservation targets against other long-term conservation targets over the same timeframe;
- While a number of leading jurisdictions have reported program annual energy savings between 0.65 and 1.25 per cent of retail sales, very few have claimed savings in excess of roughly 1.25 to 1.5 per cent of retail sales for a sustained period of time.

While the Cadmus Report gives some reasons for cautious optimism about moving forward with DSM programs at the current level, it also highlights the uniqueness of BC Hydro's combination of all three DSM tools to achieve DSM targets.

This underscores the uncertainty surrounding long-term planning estimates of energy conservation and the associated peak capacity savings. Peak capacity requirements are a primary concern for BC Hydro planning since capacity is required to meet peak load requirements and maintain system security and reliability.

References

Integrated Resource Plan (November 2013): Appendix 4D: DSM Jurisdiction Review Comparison of DSM Achievements – with modifications.

APPENDIX D – MARKET PRICE SCENARIOS

This Appendix sets out a high level description of the five Market Scenarios developed for the Integrated Resource Plan (IRP).

Any single 'best guess' of where market prices may go in the future is unlikely to be correct. BC Hydro uses Market Scenarios in the IRP to address the uncertainty of market prices and provide a framework to examine a wide range of possible market conditions and resulting different potential price paths that may develop over the planning horizon. The main market that BC Hydro transacts in is defined by the Western Electricity Coordinating Council (WECC) region.

The development and use of the Market Scenarios is based on a scenario analysis approach in which a scenario is defined as a specified collection of internally consistent[1] variables across a broad range of market situations. In particular, by letting these variables take on specific values (e.g., Scenario X might include GHG prices that are 'mid', natural gas prices that are 'low' and economic growth as 'mid'), a scenario will describe a specific way in which markets might unfold.

Four key market price variables were selected that changed across a wide, but plausible, range of values:

- Natural gas prices;
- GHG prices;
- Renewable Energy Credit (REC) prices;
- Electricity prices.

In addition, two key drivers were identified that underpin the four market variables:

- Global economic growth (low, medium, high): Within this driver, a wide range of global economic growth rates are considered, including prolonged periods of global recession. In general, low global economic growth is assumed to stall the development of GHG regulation particularly at the national level and high global economic growth is assumed to lead to faster development of GHG regulation.
- Government policy maker (regional, regional/national, national): Within this driver, it is assumed that the level of government that is developing GHG regulation is important to GHG costs. In general, regional GHG markets are assumed to result in higher prices because of the smaller pool of available GHG compliance instruments and lack of competition, whereas the development of national regulation and international protocols results in lower prices.

For IRP purposes, BC Hydro focused on five scenarios *discussed below, and summarized in Table 1*. Market Scenario 1 is BC Hydro's reference scenario and reflects current market conditions being prolonged over the long term. Market Scenario 1 aligns with the Northwest Power &

---

1 An internally consistent scenario means all variables are consistent with the overall theme in the scenario.

Conservation Council (NPCC) Mid-C electricity price forecast 'No Federal CO_2 Policy' scenario.[2] In interpreting these results, it is important to note that BC Hydro's Electricity price forecasts are based on spot market price forecasts, and do not necessarily reflect the cost of building new supply.

Table 1 Market Scenario Assumptions

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	**Low Electricity Low GHG (Regional) Low Gas**	**High Electricity High GHG (Regional) High Gas**	**Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas**	**High Electricity High GHG (Regional/Nat'l) High Gas**
GHG Actor	Regional	Regional	Regional	Regional then National	Regional then National
National GHG Cap-and-Trade Date[3]	Post-2040	Post-2040	Post-2040	2024	2024
GHG Price Level	Mid (Regional)	Low	High	Mid (Env.)	High
Natural Gas Price Level[4]	Mid (Regional)	Low	High	Mid (Env.)	High
Global Growth[5]	Mid	Low	High	Mid	High
Load Growth[6]	Expected	Flat	High	Expected	High
WECC Resource Build[7]	Expected Mix	More Gas, Less Coal and Renewable	Less Coal, more Renewable	Less Coal, more Renewable	Less Coal, more Renewable
RPS Targets[8]	Met	Met	Met	Met	Met

[2] NPCC, Draft Sixth Power Plan Mid-Term Assessment Report; http://www.nwcouncil.org/library/2012/2012-13.pdf. NPCC is a regional organization (Idaho, Montana, Oregon and Washington) that develops a 20-year regional power plan to balance energy and environmental needs. Mid-C electricity prices under the NPCC's 'Delayed Federal CO_2 Policy' scenario return to a [redacted] level from 2020 onward.

[3] 'National Cap-and-Trade Date' is the assumed year for the introduction of a national cap-and-trade system. A three-year period was used to transition from a regional scenario to a national cap-and-trade scenario.

[4] "Mid (Regional)" is B&V's 2012 spring reference case. "Mid (Env.)" is Black & Veatch's (B&V) 2012 spring environmental case. "High" and "Low" refers to B&V's spring 2012 high and low natural gas price scenarios, respectively.

[5] Global Growth "Mid" means 'expected' U.S. and Canada global demand. "High" means almost double the expected year over year compound global growth. "Low" means a flat global growth over the forecast period.

[6] Load Growth "Mid" means 'expected' U.S. and Canada and regional electric load growth per B&V's spring 2012 reference case. "High" load growth is about two times higher than the expected scenario.

[7] WECC resource build indicates the type of long-term supply mix changes assumed by B&V in each scenario.

[8] U.S. state RPS targets are met in all scenarios.

Market Scenario 1: Mid Electricity Prices, with Regional Mid GHG and Mid Gas Prices – Slow, but steady, global economic growth leads to lack of National GHG regulation in favour of regional regulation

- **Regional initiatives similar to Western Climate Initiative[9] (WCI) take the lead in establishing GHG regulatory markets in California, B.C. and Alberta, and national U.S. and Canadian governments do not follow suit in the 25-year forecast period. Medium levels of economic growth reduce federal governments' ability to advance environmental initiatives. Market Scenario 1 has a relative likelihood[10] of 60 per cent.**

Market Scenario 2: Low Electricity Prices, with Regional Low GHG and Low Gas Prices – Low economic growth delays national GHG market development

- **With slow economic growth and activity, this scenario envisions that GHG emissions start to fall worldwide, impacting the climate change debate and lowering public and government interest in GHG regulation. Lower natural gas prices and flat electricity load growth delay spending on renewable energy development and U.S. state Renewable Portfolio Standard[11] (RPS) implementation. Investments in research and development (R&D) and conservation are also down. Market Scenario 2 has a relative likelihood of 20 per cent.**

Market Scenario 3: High Electricity Prices, with Regional Mid GHG and High Gas Prices – High economic growth and lower international cooperation stifles national environmental initiatives, leaving regions to regulate

- **Although this scenario features high global economic growth, no international agreements on GHG regulation are reached due to low levels of public support for GHG regulation in the U.S. In addition to low GHG support, there is even lower public spending on renewable energy R&D. As with Market Scenario 1, California, B.C. and Alberta continue to move forward with GHG emission trading. Market Scenario 3 has a relative likelihood of 15 per cent.**

Market Scenario 4: Mid Electricity Prices, Regional/National Mid GHG and Mid Gas Prices – Mid global economic growth sees regional leaders paving the way for national GHG markets by 2024

- **Mid global growth with regional initiatives similar to WCI take the lead in establishing GHG regional regulatory markets, with national U.S. and Canadian governments following suit by 2024. Although there are delays in national renewable energy standards, development is strong in later years (post-2024), with the electricity prices**

---

9 The WCI is a collaboration of California and Quebec, with several other western U.S. states and Canadian Provinces including B.C. as observers, to identify, evaluate and implement GHG emission trading policies at a regional level.

10 Likelihoods are not to be taken as the probability that one scenario will occur. Given the infinite ways market prices can unfold, the chance that any one of these five Market Scenarios will exactly occur is essentially zero. The term 'relative likelihood' emphasizes that these judgments are made in relation to the other scenarios.

11 A RPS requires increased production of energy from qualifying renewable energy resources such as wind, solar, and biomass. The RPS generally place an obligation on public utilities and other electricity supply entities to produce a specified fraction of their electricity from qualifying renewable energy resources. RPS Regulations vary from U.S. state to state.

the same as Scenario 1 for the first 10 years but diverging thereafter. Market Scenario 4 has a relative likelihood of 4 per cent.

<u>Market Scenario 5: High Electricity Prices, Regional/National High GHG and Mid Gas Prices – Delayed high economic growth and lower international cooperation stifles national environmental initiatives, leaving regions to regulate</u>

- Although this scenario sees high global economic growth, a national GHG cap-and-trade program is delayed until at least 2024. International agreements on GHG regulation are not reached for at least 10 years due to low levels of public support for GHG regulation in the U.S., and there is lower public spending on renewable energy R&D. As with Scenario 3, California, B.C. and Alberta continue to move forward with emission trading, albeit under higher cost pressures for market participants, and accordingly electricity prices are the same as Scenario 3 for the first 10 years but diverge after that period. Market Scenario 5 has a relative likelihood of 1 per cent.

BC Hydro considers the emergence of a national GHG actor in the U.S. to be unlikely before 2023 particularly in low economic growth scenarios because establishing such a national cap-and-trade regime requires both Presidential and U.S. Congressional legislative action. This does not preclude the emergence of some U.S. federal regulatory initiatives such as U.S. Environmental Protection Agency (targeted sector-by-sector GHG regulation). Given that the overarching principle informing the Canadian Federal Government's GHG policies is to harmonize GHG initiatives with those of the U.S. Federal Government, BC Hydro also considers it unlikely that there will be a Canadian national cap-and-trade or GHG actor; again, this does not preclude targeted sector-by-sector GHG regulation. Therefore BC Hydro has not included scenarios that assume a national GHG cap-and-trade actor beginning in 2013, nor a scenario that assumes a transition to a national GHG cap-and-trade actor in the next 10 years in low economic growth conditions.

1. Natural Gas Price Forecast

The most significant development affecting natural gas prices is the emergence of shale gas. Since 2010, long-term natural gas prices have continued to drop due to advancements in gas extraction technologies and the increase in shale gas reserves with U.S. natural gas production increasing to record highs.[12] BC Hydro's Natural Gas price forecasts address these shale gas developments and potential Liquefied Natural Gas (LNG) exports, as well as the possibility that environmental concerns may limit shale gas development and cause natural gas prices to rise.

The natural gas price forecasts used in the EIS as amended and the Evidentiary Update are: (1) an input into the development of the electricity price forecast; and (2) used to define the costs of natural gas-fired generation resource options used in the modelling and risk analysis process.

[12] Refer, for example, to U.S. Energy Information Agency (EIA) figures showing gas production in 2012 reaching 66 billion cubic feet per day.

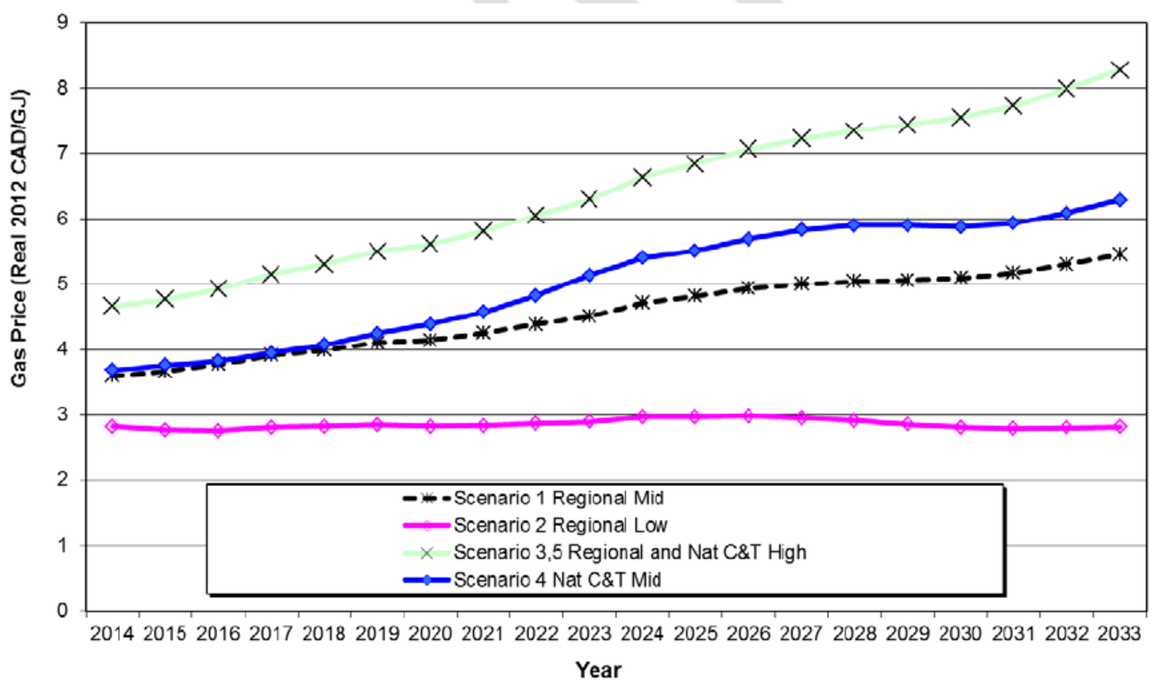
i. Forecast Methodology

In developing the IRP, BC Hydro used Ventyx's spring 2012 natural gas price forecast which is consistent with the GHG scenario assumptions listed in Table 1 above. The four natural gas price forecasts are:

- **Scenario 1 – Mid Regional Natural Gas Price Forecast:** Ventyx's reference case, which reflects their view of market conditions and includes shale gas supply
- **Scenario 2 – Low Natural Gas Price Forecast:** Ventyx's low gas price scenario, which assumes flat global demand with limited LNG exports out of North America
- **Scenario 3 – High Natural Gas Price Forecast:** Ventyx's high gas price scenario, which assumes higher global demand with shale gas environmental issues limiting gas production
- **Scenario 4 – Mid Environmental Natural Gas Price Forecast:** Ventyx's environmental scenario, which includes an uplift in natural gas demand from the reference case due to additional coal-fired generation retirement
- **Scenario 5 – High Natural Gas Price Forecast:** This forecast is the same as the high gas price in Scenario 3.

The Ventyx natural gas price forecasts are depicted in Figure 2.

Figure 2 Ventyx's Natural Gas Price Forecasts



ii. Results

Table 2 shows the four natural gas price forecasts organized according to how they were used for the five Market Scenarios.

Table 2 Natural Gas Price Forecast Scenarios (Real 2012 AD$/GJ at Sumas)

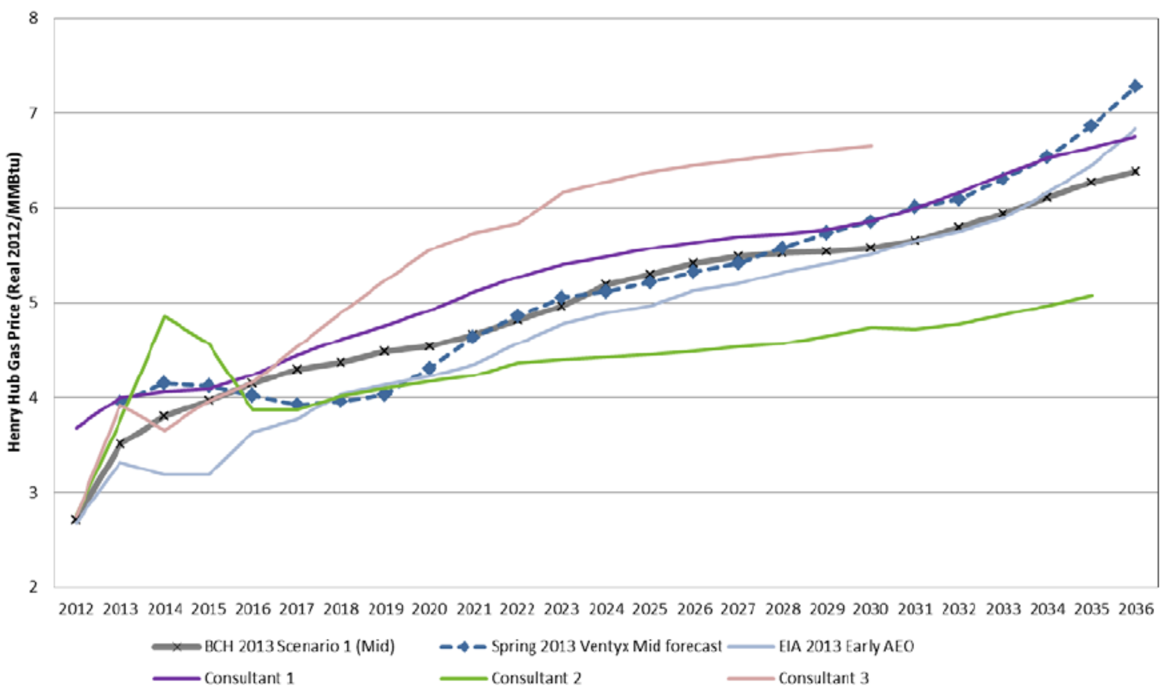
Market Scenario	1 Mid Electricity Mid GHG (Regional) Mid Gas	2 Low Electricity Low GHG (Regional) Low Gas	3 High Electricity High GHG (Regional) High Gas	4 Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	5 High Electricity High GHG (Regional/Nat'l) High Gas
2014	3.6	2.8	4.7	3.7	4.7
2015	3.7	2.8	4.8	3.8	4.8
2016	3.8	2.8	4.9	3.8	4.9
2017	3.9	2.8	5.2	3.9	5.2
2018	4.0	2.8	5.3	4.1	5.3
2019	4.1	2.8	5.5	4.2	5.5
2020	4.1	2.8	5.6	4.4	5.6
2021	4.2	2.8	5.8	4.6	5.8
2022	4.4	2.9	6.1	4.8	6.1
2023	4.5	2.9	6.3	5.1	6.3
2024	4.7	3.0	6.6	5.4	6.6
2025	4.8	3.0	6.8	5.5	6.8
2026	4.9	3.0	7.1	5.7	7.1
2027	5.0	3.0	7.2	5.8	7.2
2028	5.0	2.9	7.3	5.9	7.3
2029	5.1	2.9	7.4	5.9	7.4
2030	5.1	2.8	7.5	5.9	7.5
2031	5.2	2.8	7.7	5.9	7.7
2032	5.3	2.8	8.0	6.1	8.0
2033	5.4	2.8	8.3	6.3	8.3
2034	5.6	2.8	8.6	6.4	8.6
2035	5.8	2.8	8.9	6.5	8.9
2036	5.9	2.8	9.1	6.6	9.1
2037	5.9	2.9	9.2	6.6	9.2
2038	6.0	2.9	9.3	6.7	9.3
2039	6.0	2.9	9.4	6.8	9.4
2040	6.1	2.9	9.5	6.8	9.5

BC Hydro tracks and compares its natural gas price forecasts against other external forecasts, such as those produced by the U.S. EIA and other consultants. A graphical depiction of how BC Hydro's natural gas price forecasts compare against the U.S. EIA's 2013 forecast (at Henry Hub.[13]), three consultant forecasts and Ventyx's updated spring 2013 forecast is provided in

[13] Henry Hub is a distribution hub in Louisiana on the natural gas pipeline system; it is a pricing point for natural gas future contracts.

Figure 3. BC Hydro's Scenario 1 mid forecast is based on Ventyx's spring 2012 forecast. Note that Ventyx's 2013 forecast is down in the short term but is up in the long term. BC Hydro's Scenario 1 forecast is slightly higher than U.S. EIA's 2013 forecast for most of the forecast period, but in the middle of the three consultant forecasts.

Figure 3 Natural Gas Price Forecast Comparison – BC Hydro vs. External Forecasts



2. GHG Price Forecasts

BC Hydro used modelling that was conducted by Ventyx for their spring 2012 reference and environmental scenarios to update the five Market Scenarios described in section 1. To meet the GHG reduction measures, Ventyx's model included:

- Efficiency improvements
- Additional renewable capacity
- Retirement of inefficient coal-fired units
- Additional natural gas-fired Combined Cycle Gas Turbine units in place of new coal-fired units
- Reduced operation of existing coal-fired units
- Increased operation of existing gas-fired units
- Additional nuclear capacity, in regions where this exists or is allowed.

As emission caps decrease, GHG prices increase as the supply of emission allowances decreases over time, which leads to increased use of lower GHG-emitting electricity generation resources.

i. Results

Tables 3, 4 and 5 summarize the $/tonne GHG prices for B.C., California and the rest of the WECC respectively.

Table 3 GHG Price Forecasts by Market Scenario for B.C. (Real CAD$2012 per Tonne of CO_2e)

Market Scenario	1 Mid Electricity Mid GHG (Regional) Mid Gas	2 Low Electricity Low GHG (Regional) Low Gas	3 High Electricity High GHG (Regional) High Gas	4 Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	5 High Electricity High GHG (Regional/Nat'l) High Gas
2014	30.0	30.0	30.0	30.0	30.0
2015	30.0	30.0	30.0	30.0	30.0
2016	30.0	30.0	30.0	30.0	30.0
2017	30.0	30.0	30.0	30.0	30.0
2018	30.0	30.0	30.0	30.0	30.0
2019	30.0	30.0	30.0	30.0	30.0
2020	30.0	30.0	30.0	30.0	30.0
2021	30.0	30.0	30.0	30.0	30.0
2022	30.0	30.0	30.0	28.0	45.6
2023	30.0	30.0	30.0	26.3	63.0
2024	30.0	30.0	30.0	25.2	82.4
2025	30.0	30.0	30.0	25.3	103.9
2026	30.0	30.0	30.0	27.6	108.1
2027	30.0	30.0	30.0	30.3	112.4
2028	30.0	30.0	30.0	33.4	116.9
2029	30.0	30.0	30.0	36.7	121.6
2030	30.0	30.0	30.0	40.4	126.4
2031	30.0	30.0	30.0	44.4	131.5
2032	30.0	30.0	30.0	48.9	136.8
2033	30.0	30.0	30.0	53.7	142.2
2034	30.0	30.0	30.0	54.3	143.7
2035	30.0	30.0	30.0	54.8	145.1
2036	30.0	30.0	30.0	55.4	146.5
2037	30.0	30.0	30.0	55.9	148.0
2038	30.0	30.0	30.0	56.5	149.5
2039	30.0	30.0	30.0	57.1	151.0
2040	30.0	30.0	30.0	57.6	152.5

Table 4 GHG Price Forecasts by Market Scenario for California (Real CAD$2012 per Tonne of CO_2e)

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	High Electricity High GHG (Regional/Nat'l) High Gas
2014	19.5	12.3	67.5	19.5	67.5
2015	21.9	12.8	70.2	21.9	70.2
2016	24.7	13.3	73.0	24.7	73.0
2017	28.2	13.8	75.9	28.2	75.9
2018	32.4	14.4	79.0	32.4	79.0
2019	36.6	14.9	82.1	36.6	82.1
2020	39.9	15.5	85.4	39.9	85.4
2021	42.3	16.2	88.8	42.3	88.8
2022	44.0	16.8	92.4	38.5	92.4
2023	44.9	17.5	96.1	33.7	96.1
2024	45.8	18.2	99.9	29.2	99.9
2025	46.7	18.9	103.9	25.3	103.9
2026	47.6	19.7	108.1	27.6	108.1
2027	48.6	20.4	112.4	30.3	112.4
2028	49.5	21.3	116.9	33.4	116.9
2029	50.5	22.1	121.6	36.7	121.6
2030	51.5	23.0	126.4	40.4	126.4
2031	52.6	23.9	131.5	44.4	131.5
2032	53.6	24.9	136.8	48.9	136.8
2033	54.7	25.9	142.2	53.7	142.2
2034	55.2	26.1	143.7	54.3	143.7
2035	55.8	26.4	145.1	54.8	145.1
2036	56.4	26.6	146.5	55.4	146.5
2037	56.9	26.9	148.0	55.9	148.0
2038	57.5	27.2	149.5	56.5	149.5
2039	58.1	27.5	151.0	57.1	151.0
2040	58.6	27.7	152.5	57.6	152.5

Table 5 GHG Price Forecasts by Market Scenario for Rest of the WECC (Real CAD$2012 per Tonne of CO_2e)

Market Scenario	1 Mid Electricity Mid GHG (Regional) Mid Gas	2 Low Electricity Low GHG (Regional) Low Gas	3 High Electricity High GHG (Regional) High Gas	4 Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	5 High Electricity High GHG (Regional/Nat'l) High Gas
2014	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	5.5	23.1
2023	0.0	0.0	0.0	11.3	48.0
2024	0.0	0.0	0.0	17.7	74.9
2025	0.0	0.0	0.0	25.3	103.9
2026	0.0	0.0	0.0	27.6	108.1
2027	0.0	0.0	0.0	30.3	112.4
2028	0.0	0.0	0.0	33.4	116.9
2029	0.0	0.0	0.0	36.7	121.6
2030	0.0	0.0	0.0	40.4	126.4
2031	0.0	0.0	0.0	44.4	131.5
2032	0.0	0.0	0.0	48.9	136.8
2033	0.0	0.0	0.0	53.7	142.2
2034	0.0	0.0	0.0	54.3	143.7
2035	0.0	0.0	0.0	54.8	145.1
2036	0.0	0.0	0.0	55.4	146.5
2037	0.0	0.0	0.0	55.9	148.0
2038	0.0	0.0	0.0	56.5	149.5
2039	0.0	0.0	0.0	57.1	151.0
2040	0.0	0.0	0.0	57.6	152.5

ii. Discussion of Results

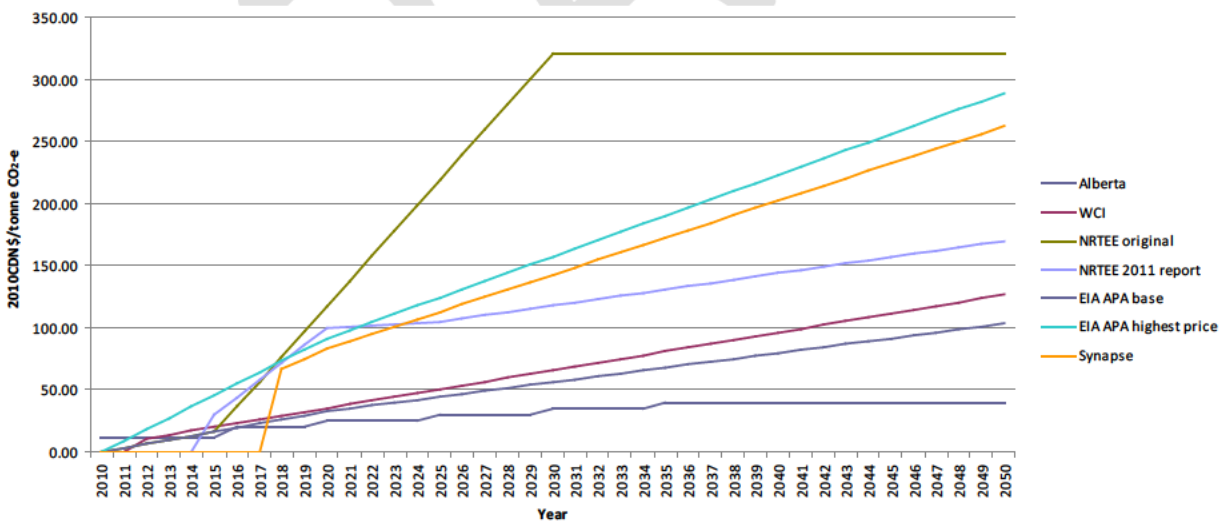
The five GHG price forecasts provide a wide range of possible future GHG offset prices that capture a range of economic and policy scenarios: two high, two mid and a low forecast. The GHG price forecasts reflect the increase in uncertainty in implementation of GHG policies, particularly in the short-term at the federal level in the U.S. and Canada.

BC Hydro benchmarked the GHG prices from the five Market Scenarios against a number of external, publicly available forecasts, which are shown graphically in Figure 4. The external GHG price forecasts examined include:

- Western Climate Initiative (WCI) Regional Cap-and-Trade Program Economic Analysis Update (July 2010)
- National Roundtable on the Environment and the Economy (NRTEE) "Getting to 2050" (2009) 'Fast and Deep scenario' (labeled 'NRTEE original' on Figure 4), and NRTEE's "Climate Prosperity – Parallel Paths: Canada-U.S. Climate Policy Choices" 2011 report 'Start 2015 scenario'
- U.S. EIA "Energy Market & Economic Impacts of the *American Power Act of 2010*", base case forecast and highest price forecasts
- Synapse Energy Economics Inc., "2011 Carbon Dioxide Price Forecast", mid-price forecast
- Carbon prices in Alberta's existing regulatory system of GHG emission intensity targets for industrial sectors, which allows compliance flexibility through the use of offsets and investment into a technology fund at a current cost of $15 for every tonne of GHG emissions above the individual emitter's limit.

The forecasts listed above were adjusted to a common unit (2010 CAD$/tonne). Where the original reports only included prices for certain years within their respective forecast period, price trajectories to 2050 were determined through straight-line interpolation and extrapolation.

Figure 4 Comparison of Publicly Available GHG Price Forecasts



- BC Hydro also examined both the B.C. carbon tax rate of $30 per tonne of CO_2e emissions and Pacific Carbon Trust's (PCT) $25/tonne price of offsets offered to the public sector for purposes of the carbon neutral commitment. BC Hydro utilized the carbon tax as it applies more broadly than PCT pricing.

The GHG price forecasts are used in the EIS and Evidentiary Update analysis in a number of ways:

- As an input to the electricity price forecast, as it is applied to all carbon dioxide (CO_2)-emitting resources in the WECC under a national cap-and-trade scenario and only to Alberta,[14] B.C. and California CO_2-emitting resources in the regional scenarios. This has the effect of uplifting electricity prices.
- As an adder to B.C. CO_2-emitting resources (natural gas-fired generation), as an expected future regulatory cost in the portfolio analysis (refer to Table 3).

3. RPS Requirements and REC Price Forecasts

A RPS is a mechanism that places an obligation on electricity suppliers to include a specified percentage of electricity from renewable energy resources such as wind and solar. Currently, 29 U.S. states and the District of Columbia have adopted mandatory RPS requirements, and an additional eight U.S. states have RPS goals. Of the 11 U.S. states that are wholly situated within the WECC region, nine have mandatory RPS requirements and two (Idaho and Wyoming) do not. The RPS requirements vary considerably by state with respect to resource eligibility, allowance for unbundled RECs[15] and enforcement arrangements.

For the portfolio analysis, BC Hydro applied the following assumptions:

- Eligibility – The resource options analysis in Section 5.5 of the EIS as amended demonstrates that the technically or economically feasible B.C.-based clean or renewable resources are Site C, Resource Smart projects such as Revelstoke Unit 6 and G.M. Shrum Units 1-5 Capacity Increase, pumped storage, run-of-river, biomass and wind. Of these resources, only wind and biomass are assumed to be eligible for REC sales.
- Prices – REC prices are capped at [redacted]h, based on the range of recent out-of-state REC prices and the expectation that excess supply will constrain prices over the next few years.
- REC Sales – BC Hydro will only sell RECs to the extent that the underlying energy is surplus to customer needs.

4. Electricity Price Forecast

WECC's electricity and natural gas markets are closely linked since natural gas has become the predominant fuel for new electricity generation. This is due to natural gas-fired generation's operational flexibility and relatively high variable operating costs, which typically place it last in the order of generation resources to be dispatched. As such, natural gas-fired generation is the marginal market resource and low gas prices are likely to drive low electricity market prices through most periods in a year.

Five electricity price forecasts were developed for the IRP based on the Ventyx Market Scenarios. The sales and purchases assumed to be made in the analysis are based on pricing at two external trading hubs – the Mid-Columbia (Mid-C) and the Alberta Energy System Operator

14 The Alberta GHG price is [redacted] for Market Scenarios 1, 2 and 3.

15 Unbundled RECs separate the attributes of renewable electricity (e.g., generator emissions) from the electricity itself, creating an entirely separate market for the renewable attribute alone, which is unencumbered by the physical constraints of the transmission grid.

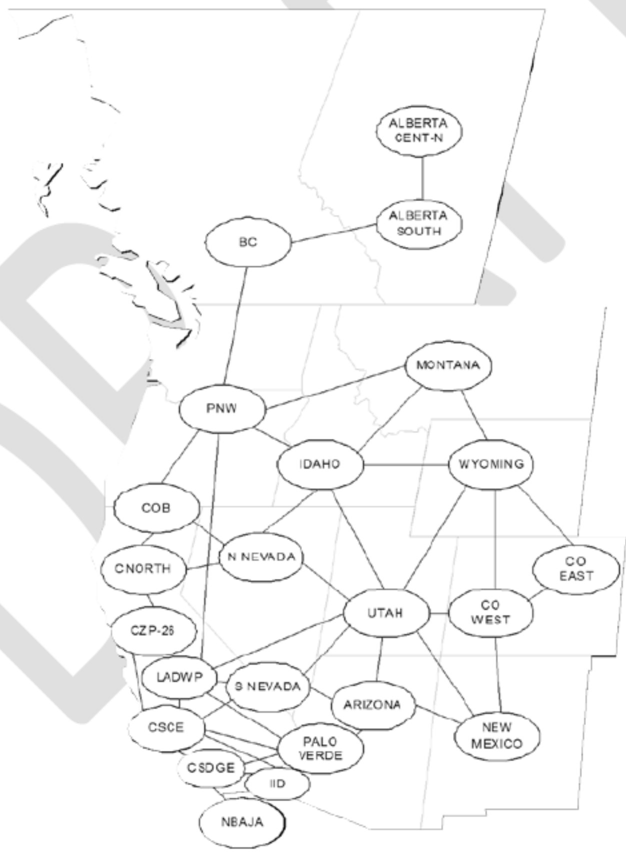
hubs. In each case, wheeling and losses are captured from the B.C. delivery point to the respective hub.

i. Forecast Methodology

Electricity prices are modelled using a computer simulation of the hourly supply-demand balance for the WECC regional market. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the market price for that hour. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. The electricity and natural gas prices are calculated for the next 25 years.

The electricity price forecasts were developed using a two-stage process. In the first stage, Ventyx compiled a database of scenarios of loads and resources in the WECC region. These scenarios include underlying assumptions for demand-side management (DSM), clean or renewable resources and conventional resources in each region (refer to Figure 5) and correspond to the Market Scenarios.

Figure 5 WECC Transmission Area Configurations



In the second stage, BC Hydro made certain modifications to the Ventyx database with respect to the B.C. area, including additional precision with respect to BC Hydro resources. BC Hydro then simulated the impact of the natural gas and GHG price forecasts described in sections 2 and 3, respectively, on the WECC region. For the two national GHG cap-and-trade scenarios BC Hydro assumed that a U.S. national cap-and-trade program will not be implemented any earlier then 2023, and therefore Scenarios 4 and 5 are the same as Scenarios 1 and 3 respectively, up until 2023.

ii. Results

The electricity price forecasts for Mid-C in Canadian dollars are provided in Figure 6 and Table 6.

Figure 6 Electricity Price Scenarios at Mid-C

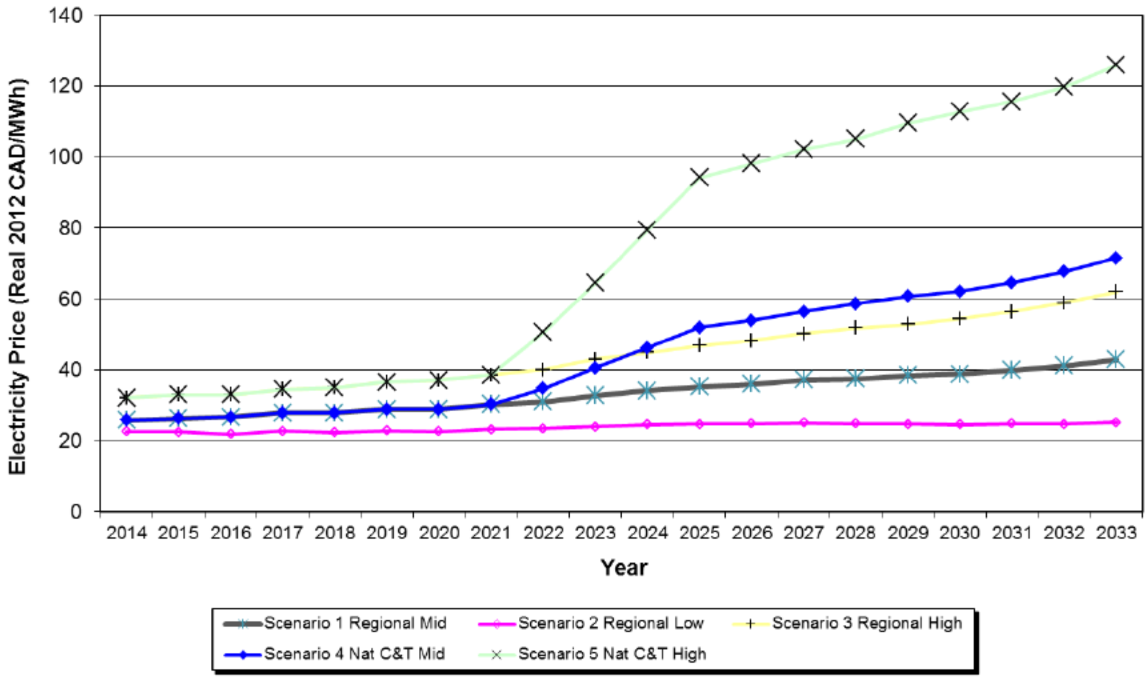


Table 6 Electricity Price Forecasts by Market Scenario (Real 2012 CAD$/MWh at Mid-C)

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	High Electricity High GHG (Regional/Nat'l) High Gas
2014	25.8	22.6	32.1	25.8	32.1
2015	26.3	22.4	32.9	26.3	32.9
2016	26.6	21.9	33.0	26.6	33.0
2017	28.0	22.7	34.5	28.0	34.5
2018	28.0	22.4	35.0	28.0	35.0
2019	28.9	22.8	36.6	28.9	36.6
2020	28.9	22.6	37.1	28.9	37.1
2021	30.2	23.2	38.5	30.2	38.5
2022	31.1	23.4	40.0	31.9	42.6
2023	32.8	23.9	43.0	36.6	53.8
2024	34.0	24.5	44.8	43.1	70.8
2025	35.3	24.8	46.8	51.9	94.1
2026	36.0	24.9	48.2	53.9	98.1
2027	37.1	25.1	50.1	56.4	102.0
2028	37.5	24.8	51.8	58.6	105.0
2029	38.4	24.7	52.7	60.7	109.5
2030	38.8	24.6	54.4	62.0	112.8
2031	39.8	24.8	56.4	64.6	115.5
2032	41.2	24.8	58.8	67.7	119.7
2033	42.8	25.2	62.0	71.5	125.9
2034	44.2	25.9	63.9	73.8	129.7
2035	46.0	27.0	66.5	76.9	135.2
2036	47.1	27.8	68.3	78.8	138.6
2037	49.3	29.0	71.3	82.3	144.7
2038	49.9	29.3	72.2	83.4	146.6
2039	50.4	29.6	72.9	84.2	148.0
2040	50.9	29.9	73.7	85.0	149.5

iii. Discussion of Results

As Table 6 shows, there is a wide range of possible future electricity market prices, which is viewed as being appropriate for use in long-term electricity planning as there can be significant variability and volatility with electricity prices.

Scenario 1 is BC Hydro's reference scenario and reflects current market conditions being prolonged over the long term. Scenario 1 aligns with the Northwest Power and Conservation Council's Mid-C electricity price forecast 'No Federal CO_2 Policy' scenario.[16] In interpreting these results, it is important to note that BC Hydro's Electricity price forecasts are based on spot market price forecasts, and do not necessarily reflect the cost of building new supply, which would be necessary under the self-sufficiency requirement of the Clean Energy Act . In addition, they indicate yearly averages and do not show hourly or seasonal variability that is embedded in the forecast details that is used in the portfolio PV analysis.

5. Market Scenario Weightings

Weighting factors are used to assign a relative probability to each scenario. The process of developing the weighting factors, the results and the process used to update the weighting factors are described in this section.

In 2011, BC Hydro worked with Black & Veatch to assign relative likelihoods to each of the five Market Scenarios.[17] This exercise considered the relative likelihood of the whole scenario and not the underlying variables or drivers. These estimates were developed using a Modified Delphi method, which systematically assists experts to reach a consensus on the relative probabilities.

In developing the 2013 Market Scenarios, BC Hydro updated the relative likelihood assessment and assigned weighting factors to the Scenarios. BC Hydro reviewed the four variables associated with the five Market Scenarios and ranked the scenarios from most likely to least likely, as follows:

- Scenario 1, which is based on Ventyx's spring 2012 reference forecast, is the most likely scenario
- Scenario 5 (high electricity price, high GHG price due to national government GHG regulation and high natural gas price) is the least likely based on shale gas development and the stalled development of GHG regulation at the U.S. federal level (with the resulting slower development of Canadian federal GHG regulation given that the Government of Canada's position that it will harmonize GHG regulation with U.S. federal government actions)
- Scenario 4 is not likely as it assumes a national GHG cap-and-trade program
- Scenarios 2 and 3 assume regional as opposed to national GHG cap-and-trade regulation. BC Hydro determined that Market Scenario 2 was more likely than Market Scenario 3 as lower natural gas prices are expected to prevail over the IRP planning horizon.

The results are shown in Table 7.

---

16 Northwest Power and Conservation Council's (NPCC), Draft Sixth Power Plan Mid-Term Assessment Report; http://www.nwcouncil.org/library/2012/2012-13.pdf. NPCC is a regional organization (Idaho, Montana, Oregon and Washington) that develops a 20-year regional power plan to balance energy and environmental needs. Mid-C electricity prices under the NPCC's 'Delayed Federal CO_2 Policy' scenario return to a \$50/MWh to \$60/MWh level from 2020 onward.

17 Likelihoods are not to be taken as the probability that one scenario will occur. Given the infinite ways market prices can unfold, the chance that any one of these scenarios will exactly occur is essentially zero. The use of the term 'relative likelihood' emphasizes that these judgments are made in relation to the other scenarios.

Table 7 Relative Likelihoods

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	**Low Electricity Low GHG (Regional) Low Gas**	**High Electricity High GHG (Regional) High Gas**	**Mid Electricity Mid GHG (Region/Nat'l) Mid Gas**	**High Electricity High GHG (Region/Nat'l) High Gas**
Relative Likelihood	60%	20%	15%	4%	1%

APPENDIX E1 – PORTFOLIO MODELLING

System Optimizer and Portfolio Construction

BC Hydro built a number of portfolios to compare the Project to available resources. Resource portfolios were developed using System Optimizer, a product of Ventyx that has been adopted by several utilities in North America.

System Optimizer (SO) is a linear optimization model that selects the optimal combinations of available resource options and timing under different assumptions and constraints that will meet the energy and capacity needs of BC Hydro's customers as defined in Section 5.2. In constructing the portfolios, SO takes a planning perspective ensuring that the portfolio meets reliability constraints, as well as an operating perspective evaluating the operating performance of the portfolio. The planning perspective requires that the firm energy and dependable capacity of the selected resource portfolio be sufficient to meet system energy and capacity demands respectively, including an allowance for a capacity reserve margin. The operation of the portfolio is simulated taking into account average energy output of the resources and includes sales of portfolio surpluses into export markets. System Optimizer does not capture either resource delivery risk, or the value of ancillary benefits (such as the ability to integrate intermittent resources and firming capability), which could be significant for resources such as the Project.

The model assesses the interaction of future generation and transmission resource options with the existing system and evaluates the manner in which the portfolio can be operated to maximize market revenue while meeting domestic load. It also takes into account system constraints such as minimum generation requirements and transmission constraints both within B.C. and on interties with US and Alberta.

The annual cost of operating the portfolio is a combination of market revenue, transmission costs, and the fixed and variable costs of generation and transmission resources. Fixed costs include capital charges and fixed operating and maintenance costs while variable costs include cost of renewable IPP energy, fuel costs, GHG offset costs, and transmission wheeling costs. The model seeks to minimize the present value of these costs over the planning time period in selecting an optimal resource portfolio.

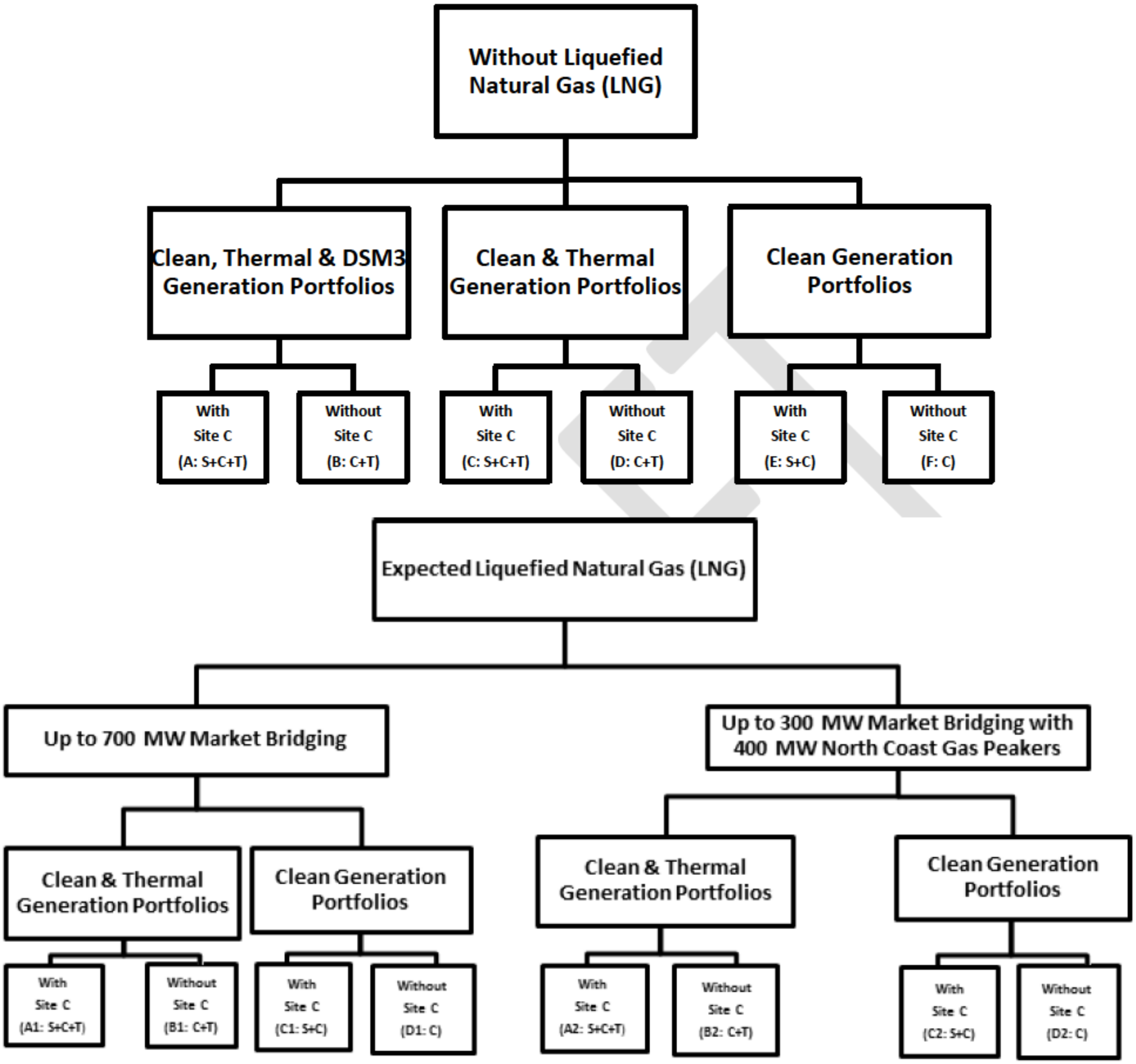
BC Hydro created several portfolios to compare the Project to available resources. The key portfolios making up the base case analysis are:

1. Clean Generation Portfolios
    a. With Expected Liquefied Natural Gas (LNG) loads
        i. With Site C (up to 700 MW market bridging prior to Site C)
        ii. Without Site C (up to 700 MW market bridging prior to Site C)
        iii. With Site C (up to 300 MW market bridging with 400 MW North Coast gas peakers)
        iv. Without Site C (up to 300 MW market bridging with 400 MW North Coast gas peakers)
    b. Without LNG
        i. With Site C
        ii. Without Site C

2. Clean & Thermal Generation Portfolios
    a. With Expected Liquefied Natural Gas (LNG) loads
        i. With Site C (up to 700 MW market bridging prior to Site C)
        ii. Without Site C (up to 700 MW market bridging prior to Site C)
        iii. With Site C (up to 300 MW market bridging with 400 MW North Coast gas peakers)
        iv. Without Site C (up to 300 MW market bridging with 400 MW North Coast gas peakers)
    b. Without LNG
        i. With Site C
        ii. Without Site C
3. Clean, Thermal & Demand Side Management (DSM) Option 3 Portfolios
    a. Without LNG
        i. With Site C
        ii. Without Site C

Please refer to the table below showing the base case portfolio runs. The present value of the portfolio cost in $F2013 is also shown in the following table.

Portfolio Analysis Runs:



Portfolio Analysis PV of Costs Results:

Portfolio Name	LNG Scenario	Portfolio Description	Portfolio PV ($F2013M)	Portfolio PV Difference to Equivalent Portfolio with Site C
A: S+C+T	No LNG	Site C + Other clean and thermal resources	[redacted]	[redacted]
B: C+T	No LNG	Other clean and thermal resources (DSM3)	[redacted]6	
C: S+C+T	No LNG	Site C + Other clean and thermal resources	[redacted]	[redacted]
D: C+T	No LNG	Other clean and thermal resources	[redacted]	
E: S+C	No LNG	Site C + Other clean resources	[redacted]	[redacted]
F: C	No LNG	Other clean resources	[redacted]	
A1: S+C+T	Expected	Site C + Other clean and thermal resources (700 MW market bridging)	[redacted]	[redacted]
B1: C+T	Expected	Other clean and thermal resources (700 MW market bridging)	[redacted]	
C1: S+C	Expected	Site C + Other clean resources (700 MW market bridging)	[redacted]	[redacted]
D1: C	Expected	Other clean resources (700 MW market bridging)	[redacted]	
A2: S+C+T	Expected	Site C + Other clean and thermal resources (300 MW market bridging)	[redacted]	[redacted]
B2: C+T	Expected	Other clean and thermal resources (300 MW market bridging)	[redacted]	
C2: S+C	Expected	Site C + Other clean resources (300 MW market bridging)	[redacted]	[redacted]
D2: C	Expected	Other clean resources (300 MW market bridging)	[redacted]	

The details of the portfolios are presented below with three tables shown for each portfolio.

- The first table shows the energy resources selected. The resource name, type, in-service date as determined by the System Optimizer model, installed capacity, average annual energy, and the Unit Energy Cost (UEC) are shown. The UEC shown is the cost of the resource at the point of interconnection and does not include integration costs, transmission costs, capacity costs, freshet firm energy costs, time of delivery costs, and costs associated with disposal of non-firm energy. These costs are reflected in the Present Value (PV) of the portfolios shown above.
- The second table shows the capacity resources selected. The capacity costs shown reflect only the fixed costs of the resource. The cost of operating these resources to meet peak demand is reflected in the portfolio PV, as is the cost of acquiring additional energy resources to meet the energy losses in the case of Pumped Storage facilities.

- The third table shows the transmission upgrades that are required on the bulk transmission system to accommodate the generation resources. The cost of these upgrades is reflected in the portfolio PV.

SHORTNAME **Portfolio A: S+C+T**	*Description* Site C with clean and thermal resources	***Portfolio Code*** **MFM_1LT_NN0_05Q**

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC ($/MWh)**
Site C	Large Hydro	2023	1100	5100	[redacted]
MSW2_LM	Municipal Solid Waste	2031	25	208	[redacted]
Wind_PC28	Wind	2035	153	591	[redacted]
Run of River LM 80_100	Run of River	2035	62	174	[redacted]
Wind_PC14	Wind	2036	144	527	[redacted]
Wind_PC19	Wind	2036	117	441	[redacted]
Wind_PC21	Wind	2036	99	371	[redacted]
MSW1_VI	Municipal Solid Waste	2036	12	100	[redacted]
Wind_PC13	Wind	2037	135	541	[redacted]
Wind_PC16	Wind	2037	99	377	[redacted]
Wind_PC10	Wind	2038	297	1023	[redacted]
Wind_PC20	Wind	2039	159	610	[redacted]
Wind_PC15	Wind	2040	108	382	[redacted]
Biomass_VI	Biomass	2040	30	239	[redacted]

Capacity Resources Required for Portfolio A					
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**Unit Cost of Capacity ($/kW-year)**
GMS Units 1-5 Cap Increase	Resource Smart	2029	220		[redacted]
Revelstoke Unit 6	Resource Smart	2030	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2032	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2033	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2034	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2035	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2036	103	150	[redacted]
Pumped_Storage_LM	Pumped Storage	2037	1000		[redacted]

Transmission Required for Portfolio A		
Year	**Name**	**Capital Cost ($M)**
2023	Shunt compensation at WSN KLY	[redacted]
2029	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2029	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2030	Series compensation of 5L91 and 5L98	[redacted]
2033	500 kV circuit 5L46 between KLY and Cheekye	[redacted]
2040	500kV circuit 5L14 between WSN and KLY	[redacted]

SHORTNAME	*Description*	*Portfolio Code*
Portfolio B: C+T	Clean and thermal resources (DSM3)	**MCM_1NT_NN0_05Q**

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC ($/M** [redacted]
Wind_PC21	Wind	2029	99	371	[redacted]
MSW2_LM	Municipal Solid Waste	2029	25	208	[redacted]
Wind_PC13	Wind	2030	135	541	[redacted]
Wind_PC10	Wind	2031	297	1023	[redacted]
MSW1_VI	Municipal Solid Waste	2031	12	100	[redacted]
Wind_PC14	Wind	2032	144	527	[redacted]
Wind_PC28	Wind	2032	153	591	[redacted]
Wind_PC15	Wind	2033	108	382	[redacted]
Wind_PC16	Wind	2033	99	377	[redacted]
Wind_PC19	Wind	2033	117	441	[redacted]
Wind_PC11	Wind	2034	126	473	[redacted]
Wind_PC20	Wind	2034	159	610	[redacted]
Run of River LM 80_100	Run of River	2034	62	174	[redacted]
Wind_PC09	Wind	2035	207	713	[redacted]
Wind_PC42	Wind	2035	63	219	[redacted]
Wind_PC18	Wind	2036	138	486	[redacted]
Wind_PC41	Wind	2036	45	155	[redacted]
Wind_PC26	Wind	2037	126	416	[redacted]
Wind_VI12	Wind	2037	48	150	[redacted]
Wind_VI14	Wind	2037	35	114	[redacted]
Biomass_VI	Biomass	2037	30	239	[redacted]
Biomass_SE	Biomass	2038	33	263	[redacted]
Biomass_LM	Biomass	2038	30	239	[redacted]
Biomass_PR	Biomass	2039	28	223	[redacted]
Biomass_NC	Biomass	2039	13	104	[redacted]
Biomass_CI	Biomass	2039	41	327	[redacted]
Biomass_EK	Biomass	2039	28	223	[redacted]
Wind_NC09	Wind	2040	334	1026	[redacted]
Run of River VI 100_110	Run of River	2040	119	451	[redacted]

Capacity Resources Required for Portfolio B					
Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Cost of Capacity ($/kW-year)
GMS Units 1-5 Cap Increase	Resource Smart	2023	220		[redacted]
Revelstoke Unit 6	Resource Smart	2025	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2028	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2029	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2030	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2031	103	150	[redacted]
Pumped_Storage_LM	Pumped Storage	2032	1000		[redacted]
100 MW SCGT KN	Natural Gas	2037	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2038	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2039	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2040	103	150	[redacted]

Transmission Required for Portfolio B		
Year	Name	Capital Cost [redacted]
2025	Series compensation of 5L91 and 5L98	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2033	Shunt compensation at WSN KLY	[redacted]
2035	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2035	Series compensation 5L11_12_13 from WSN to KLY	[redacted]

SHORTNAME **Portfolio C: S+C+T**		*Description* Site C + Other clean and thermal resources		*Portfolio Code* **M&M_1LT_NN0_05Q**	
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC ($/MWh)** [redacted]
Site C	Large Hydro	2023	1100	5100	[redacted]
Wind_PC19	Wind	2037	117	441	[redacted]
Wind_PC13	Wind	2038	144	527	[redacted]
Wind_PC28	Wind	2038	153	591	[redacted]
MSW1_VI	Municipal Solid Waste	2038	12	100	[redacted]
Biomass_VI	Biomass	2038	30	239	[redacted]
MSW2_LM	Municipal Solid Waste	2038	25	208	[redacted]
Wind_PC21	Wind	2040	99	371	[redacted]

Capacity Resources Required for Portfolio C

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**Unit Cost of Capacity ($/kW-year)** [redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2029	220		[redacted]
Revelstoke Unit 6	Resource Smart	2030	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2033	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2034	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2035	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2036	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2037	103	150	[redacted]
Pumped_Storage_LM	Pumped Storage	2039	1000		[redacted]

Transmission Required for Portfolio C

Year	**Name**	**Capital** [redacted]
2023	Shunt compensation at WSN KLY	[redacted]
2029	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2029	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2030	Series compensation of 5L91 and 5L98	[redacted]
2033	500 kV circuit 5L46 between KLY and Cheekye	[redacted]

SHORTNAME **Portfolio D: C+T**		*Description* Other clean and thermal resources		*Portfolio Code* **MCM_1NT_NN0_05Q**	
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC ($/MWh)**
MSW1_VI	Municipal Solid Waste	2027	12	100	[redacted]
MSW2_LM	Municipal Solid Waste	2027	25	208	[redacted]
Wind_VI12	Wind	2028	48	150	[redacted]
Wind_PC28	Wind	2029	153	591	[redacted]
Wind_PC21	Wind	2030	99	371	[redacted]
Wind_PC13	Wind	2031	135	541	[redacted]
Wind_PC10	Wind	2032	297	1023	[redacted]
Wind_PC19	Wind	2032	117	441	[redacted]
Biomass_VI	Biomass	2032	30	239	[redacted]
Biomass_LM	Biomass	2032	30	239	[redacted]
Wind_PC14	Wind	2034	144	527	[redacted]
Wind_PC16	Wind	2034	99	377	[redacted]
Wind_PC20	Wind	2035	159	610	[redacted]
Wind_PC15	Wind	2036	108	382	[redacted]
Wind_PC09	Wind	2037	207	713	[redacted]
Wind_PC11	Wind	2038	126	473	[redacted]
Wind_PC41	Wind	2039	45	155	[redacted]
Wind_VI14	Wind	2039	35	114	[redacted]
Run of River LM 80_100	Run of River	2039	62	174	[redacted]

Capacity Resources Required for Portfolio D					
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**Unit Cost [redacted] Capacity ([redacted] year)**
GMS Units 1-5 Cap Increase	Resource Smart	2023	220		[redacted]
Revelstoke Unit 6	Resource Smart	2023	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2027	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2028	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2029	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2030	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2031	103	150	[redacted]
Pumped_Storage_LM	Pumped Storage	2033	1000		[redacted]
100 MW SCGT KN	Natural Gas	2040	206	300	[redacted]

Transmission Required for Portfolio D		
Year	**Name**	**Capital C**[redacted]
2023	Series compensation of 5L91 and 5L98	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2034	Shunt compensation at WSN KLY	[redacted]
2038	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2038	Series compensation 5L11_12_13 from WSN to KLY	[redacted]

SHORTNAME **Portfolio E: S+C**		*Description* Site C with Other clean resources		***Portfolio Code*** **M&M_1LC_NN0_05** [redacted]
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC** [redacted]
Site C	Large Hydro	2023	1100	5100	[redacted]
Wind_PC28	Wind	2034	153	591	[redacted]
MSW2_LM	Municipal Solid Waste	2034	25	208	[redacted]
Wind_PC19	Wind	2035	117	441	[redacted]
Wind_PC21	Wind	2035	99	371	[redacted]
Wind_PC16	Wind	2036	99	377	[redacted]
Wind_PC13	Wind	2037	135	541	[redacted]
MSW1_VI	Municipal Solid Waste	2037	12	100	[redacted]
Biomass_VI	Biomass	2038	30	239	[redacted]
Biomass_LM	Biomass	2038	30	239	[redacted]
Wind_PC14	Wind	2039	144	527	[redacted]
Wind_PC10	Wind	2040	297	1023	[redacted]
Wind_PC41	Wind	2040	45	155	[redacted]

Capacity Resources Required for Portfolio E					[redacted]
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	[redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2029	220		[redacted]
Revelstoke Unit 6	Resource Smart	2030	500	26	[redacted]
Pumped_Storage_LM	Pumped Storage	2032	1000		[redacted]

Transmission Required for Portfolio E		[redacted]
Year	**Name**	[redacted]
2023	Shunt compensation at WSN KLY	[redacted]
2029	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2029	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2030	Series compensation of 5L91 and 5L98	[redacted]

SHORTNAME	*Description*	*Portfolio Code*
Portfolio F: C	Other clean resources	**M&M_1NC_NN0_05** [redacted]

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC** [redacted]
Wind_PC13	Wind	2027	135	541	[redacted]
Wind_PC21	Wind	2027	99	371	[redacted]
Wind_PC28	Wind	2027	153	591	[redacted]
MSW2_LM	Municipal Solid Waste	2027	25	208	[redacted]
Wind_PC16	Wind	2029	99	377	[redacted]
Wind_PC19	Wind	2029	117	441	[redacted]
Wind_PC14	Wind	2030	144	527	[redacted]
MSW1_VI	Municipal Solid Waste	2030	12	100	[redacted]
Wind_PC20	Wind	2031	159	610	[redacted]
Wind_PC41	Wind	2031	45	155	[redacted]
Wind_PC15	Wind	2032	108	382	[redacted]
Wind_PC09	Wind	2033	207	713	[redacted]
Wind_PC10	Wind	2034	297	1023	[redacted]
Wind_PC18	Wind	2035	138	486	[redacted]
Wind_PC42	Wind	2035	63	219	[redacted]
Biomass_PR	Biomass	2035	28	223	[redacted]
Wind_VI12	Wind	2035	48	150	[redacted]
Wind_VI14	Wind	2035	35	114	[redacted]
Biomass_VI	Biomass	2035	30	239	[redacted]
Biomass_LM	Biomass	2035	30	239	[redacted]
Wind_PC11	Wind	2037	126	473	[redacted]
Run of River LM 80_100	Run of River	2037	62	174	[redacted]
Wind_PC26	Wind	2038	126	416	[redacted]
Wind_VI13	Wind	2038	35	106	[redacted]
Wind_PC48	Wind	2039	152	505	[redacted]
Biomass_SE	Biomass	2040	33	263	[redacted]

Capacity Resources Required for Portfolio F					[redacted]
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	[redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2023	220		[redacted]
Revelstoke Unit 6	Resource Smart	2023	500	26	[redacted]
Pumped_Storage_LM	Pumped Storage	2028	1000		[redacted]
Pumped_Storage_LM	Pumped Storage	2036	1000		[redacted]

Transmission Required for Portfolio F		[redacted]
Year	**Name**	
2023	Series compensation of 5L91 and 5L98	
2032	Shunt compensation at WSN KLY	
2035	Series compensation 5L1_2_3_7 from GMS to WSN	
2035	Series compensation 5L11_12_13 from WSN to KLY	

SHORTNAME **Portfolio A1: S+ C+T**	*Description* Site C + Other clean and thermal resources (market bridging)	***Portfolio Code*** **M&M_1LT_2N0_0**[redacted]

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**U**[redacted]
Site C	Large Hydro	2023	1100	5100	[redacted]
MSW2_LM	Municipal Solid Waste	2031	25	208	[redacted]
Wind_PC28	Wind	2033	153	591	[redacted]
Wind_PC13	Wind	2034	135	541	[redacted]
Wind_PC21	Wind	2034	99	371	[redacted]
Wind_PC19	Wind	2035	117	441	[redacted]
MSW1_VI	Municipal Solid Waste	2035	12	100	[redacted]
Wind_PC16	Wind	2036	99	377	[redacted]
Wind_PC14	Wind	2037	144	527	[redacted]
Biomass_LM	Biomass	2038	30	239	[redacted]
Biomass_PR	Biomass	2039	28	223	[redacted]
Biomass_CI	Biomass	2039	41	327	[redacted]
Biomass_SE	Biomass	2039	33	263	[redacted]
Biomass_VI	Biomass	2039	30	239	[redacted]
Wind_PC10	Wind	2040	297	1023	[redacted]

Capacity Resources Required for Portfolio A1

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**U C y**[redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2027	220		[redacted]
100 MW SCGT NC	Natural Gas	2028	206	300	[redacted]
100 MW SCGT NC	Natural Gas	2029	206	300	[redacted]
100 MW SCGT NC	Natural Gas	2030	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2030	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2031	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2032	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2033	103	150	[redacted]
Revelstoke Unit 6	Resource Smart	2034	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2035	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2037	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2038	103	150	[redacted]
100 MW SCGT NC	Natural Gas	2040	103	150	[redacted]

Transmission Required for Portfolio A1		
Year	Name	[redacted]
2019	Series compensation of WSN-GLN 500 kV line	[redacted]
2023	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2023	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2027	Shunt compensation at WSN KLY	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2033	500 kV circuit 5L46 between KLY and Cheekye	[redacted]
2034	Series compensation of 5L91 and 5L98	[redacted]
2040	500kV circuit 5L14 between WSN and KLY	[redacted]

SHORTNAME **Portfolio B1: C+T**		*Description* Other clean and thermal resources (market bridging)		***Portfolio Code*** **M&M_1NT_2N0_05** [redacted]	
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**UEC** [redacted]
Wind_PC19	Wind	2023	117	441	[redacted]
Wind_PC21	Wind	2023	99	371	[redacted]
Wind_PC28	Wind	2023	153	591	[redacted]
MSW2_LM	Municipal Solid Waste	2023	25	208	[redacted]
Wind_PC13	Wind	2026	135	541	[redacted]
Wind_PC16	Wind	2028	99	377	[redacted]
Wind_PC10	Wind	2029	297	1023	[redacted]
Wind_PC14	Wind	2030	144	527	[redacted]
MSW1_VI	Municipal Solid Waste	2031	12	100	[redacted]
Biomass_VI	Biomass	2031	30	239	[redacted]
Run of River LM 80_100	Run of River	2031	62	174	[redacted]
Wind_VI14	Wind	2032	35	114	[redacted]
Biomass_LM	Biomass	2032	30	239	[redacted]
Wind_PC09	Wind	2033	207	713	[redacted]
Wind_PC15	Wind	2033	108	382	[redacted]
Wind_PC20	Wind	2033	159	610	[redacted]
Wind_PC11	Wind	2034	126	473	[redacted]
Wind_PC41	Wind	2034	45	155	[redacted]
Wind_PC18	Wind	2035	138	486	[redacted]
Wind_PC42	Wind	2035	63	219	[redacted]
Wind_PC26	Wind	2036	126	416	[redacted]
Run of River VI 100_110	Run of River	2037	119	352	[redacted]
Run of River LM 100_110	Run of River	2037	102	258	[redacted]
Wind_PC48	Wind	2038	152	505	[redacted]
Wind_PC43	Wind	2039	41	138	[redacted]
Biomass_SE	Biomass	2040	33	263	[redacted]

Capacity Resources Required for Portfolio B1				
Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)
GMS Units 1-5 Cap Increase	Resource Smart	2023	220	
100 MW SCGT NC	Natural Gas	2023	309	450
100 MW SCGT KN	Natural Gas	2023	103	150
100 MW SCGT KN	Natural Gas	2024	103	150
100 MW SCGT NC	Natural Gas	2025	103	150
100 MW SCGT KN	Natural Gas	2025	103	150
100 MW SCGT NC	Natural Gas	2027	103	150
100 MW SCGT KN	Natural Gas	2027	206	300
100 MW SCGT KN	Natural Gas	2028	103	150
Revelstoke Unit 6	Resource Smart	2029	500	26
100 MW SCGT KN	Natural Gas	2031	103	150
Pumped_Storage_LM	Pumped Storage	2033	1000	
100 MW SCGT KN	Natural Gas	2039	206	300

[redacted]

Transmission Required for Portfolio B1	
Year	Name
2019	Series compensation of WSN-GLN 500 kV line
2029	Shunt compensation at WSN KLY
2029	Series compensation of 5L91 and 5L98
2029	Shunt compensation at NIC and MDN
2033	Series compensation 5L1_2_3_7 from GMS to WSN
2033	Series compensation 5L11_12_13 from WSN to KLY
2040	500kV circuit 5L14 between WSN and KLY

[redacted]

SHORTNAME **Portfolio C1: S+C**		*Description* Site C + Other clean resources (market bridging)		***Portfolio Code*** **M&M_1LC_2N0_** [redacted]
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	[redacted]
Site C	Large Hydro	2023	1100	5100	
Wind_PC28	Wind	2030	153	591	
MSW1_VI	Municipal Solid Waste	2030	12	100	
MSW2_LM	Municipal Solid Waste	2030	25	208	
Wind_PC13	Wind	2031	135	541	
Wind_PC14	Wind	2031	144	527	
Wind_PC19	Wind	2032	117	441	
Wind_PC16	Wind	2033	99	377	
Wind_PC21	Wind	2033	99	371	
Wind_PC10	Wind	2034	297	1023	
Wind_PC20	Wind	2035	159	610	
Wind_PC15	Wind	2036	108	382	
Wind_PC09	Wind	2037	207	713	
Wind_PC41	Wind	2038	45	155	
Wind_PC42	Wind	2038	63	219	
Wind_VI12	Wind	2038	48	150	
Biomass_VI	Biomass	2038	30	239	
Biomass_LM	Biomass	2038	30	239	
Wind_PC11	Wind	2039	126	473	
Run of River LM 80_100	Run of River	2039	62	174	
Run of River KN 90_100	Run of River	2040	72	172	
Wind_VI13	Wind	2040	35	106	

Capacity Resources Required for Portfolio C1					
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**Un Ca ye** [redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2027	220		
Revelstoke Unit 6	Resource Smart	2028	500	26	
Pumped_Storage_LM	Pumped Storage	2031	1000		
Pumped_Storage_LM	Pumped Storage	2039	1000		

Transmission Required for Portfolio C1

Year	Name	[redacted]
2019	Series compensation of WSN-GLN 500 kV line	[redacted]
2023	Shunt compensation at WSN KLY	[redacted]
2027	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2027	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2028	Series compensation of 5L91 and 5L98	[redacted]
2029	Shunt compensation at NIC and MDN	[redacted]
2039	500kV circuit 5L8 between GMS and WSN	[redacted]
2039	500kV circuit 5L14 between WSN and KLY	[redacted]

SHORTNAME **Portfolio D1: C**	*Description* Other clean resources (market bridging)	***Portfolio Code*** **M&M_1NC_2NO_05U**

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	[redacted]
Wind_PC13	Wind	2023	135	541	[redacted]
Wind_PC19	Wind	2023	117	441	[redacted]
Wind_PC21	Wind	2023	99	371	[redacted]
Wind_PC28	Wind	2023	153	591	[redacted]
MSW1_VI	Municipal Solid Waste	2023	12	100	[redacted]
MSW2_LM	Municipal Solid Waste	2023	25	208	[redacted]
Biomass_VI	Biomass	2024	30	239	[redacted]
Wind_PC10	Wind	2025	297	1023	[redacted]
Wind_PC42	Wind	2026	63	219	[redacted]
Wind_PC14	Wind	2027	144	527	[redacted]
Wind_PC41	Wind	2027	45	155	[redacted]
Wind_PC15	Wind	2028	108	382	[redacted]
Wind_PC16	Wind	2029	99	377	[redacted]
Wind_PC20	Wind	2029	159	610	[redacted]
Wind_PC18	Wind	2030	138	486	[redacted]
Wind_VI12	Wind	2030	48	150	[redacted]
Wind_PC09	Wind	2031	207	713	[redacted]
Biomass_LM	Biomass	2032	30	239	[redacted]
Wind_NC09	Wind	2033	334	1026	[redacted]
Wind_PC11	Wind	2034	126	473	[redacted]
Wind_PC48	Wind	2034	152	505	[redacted]
Run of River KN 90_100	Run of River	2034	72	172	[redacted]
Wind_VI14	Wind	2034	35	114	[redacted]
Run of River LM 80_100	Run of River	2034	62	174	[redacted]
Wind_PC26	Wind	2035	126	416	[redacted]
Run of River LM 100_110	Run of River	2035	102	258	[redacted]
Run of River KN 100_110	Run of River	2036	75	170	[redacted]
Wind_VI13	Wind	2036	35	106	[redacted]
Wind_PC06	Wind	2037	243	761	[redacted]
Run of River VI 100_110	Run of River	2038	119	352	[redacted]
Wind_VI15	Wind	2038	41	124	[redacted]
Wind_PC40	Wind	2039	117	349	[redacted]
Biomass_VI	Biomass	2039	30	239	[redacted]
Biomass_SE	Biomass	2040	33	263	[redacted]

Capacity Resources Required for Portfolio D1					
Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Cost of Capacity ($/kW- [redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2023	220		[redacted]
Revelstoke Unit 6	Resource Smart	2023	500	26	[redacted]
Pumped_Storage_LM	Pumped Storage	2026	1000		[redacted]
Pumped_Storage_LM	Pumped Storage	2034	1000		[redacted]

Transmission Required for Portfolio D1		
Year	Name	[redacted]
2019	Series compensation of WSN-GLN 500 kV line	[redacted]
2023	Series compensation of 5L91 and 5L98	[redacted]
2028	Shunt compensation at WSN KLY	[redacted]
2033	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2033	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2039	500kV circuit 5L14 between WSN and KLY	[redacted]

SHORTNAME Portfolio A2: S+C+T	*Description* Site C + Other clean and thermal resources (partial gas bridging)	*Portfolio Code* MKM_1LT_2N0_0[redacted]

Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	[redacted]
Site C	Large Hydro	2023	1100	5100	[redacted]
MSW2_LM	Municipal Solid Waste	2031	25	208	[redacted]
Wind_PC21	Wind	2033	99	371	[redacted]
Wind_PC28	Wind	2033	153	591	[redacted]
Wind_PC19	Wind	2034	117	441	[redacted]
MSW1_VI	Municipal Solid Waste	2034	12	100	[redacted]
Wind_PC13	Wind	2035	135	541	[redacted]
Wind_PC16	Wind	2036	99	377	[redacted]
Wind_PC14	Wind	2037	144	527	[redacted]
Wind_PC41	Wind	2038	45	155	[redacted]
WBBio_VI	Biomass	2038	30	239	[redacted]
WBBio_LM	Biomass	2038	30	239	[redacted]
Wind_PC10	Wind	2039	297	1023	[redacted]
Wind_PC15	Wind	2039	108	382	[redacted]
WBBio_SP	Biomass	2039	28	223	[redacted]
WBBio_MAC	Biomass	2039	41	327	[redacted]
WBBio_WK	Biomass	2039	33	263	[redacted]

Capacity Resources Required for Portfolio A2

Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	[redacted]
50 MW SCGT PR	Natural Gas	2018	50	394	[redacted]
100 MW SCGT NC	Natural Gas	2019	412	600	[redacted]
50 MW SCGT PR	Natural Gas	2020	50	394	[redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2029	220	0	[redacted]
Revelstoke Unit 6	Resource Smart	2030	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2032	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2034	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2035	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2036	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2037	309	450	[redacted]
100 MW SCGT KN	Natural Gas	2038	103	150	[redacted]
Pumped_Storage_LM	Pumped Storage	2040	1000		[redacted]

Transmission Required for Portfolio A2

Year	Name	[redacted]
2023	Shunt compensation at WSN KLY	[redacted]
2028	Shunt compensation at NIC and MDN	[redacted]
2029	Series compensation 5L1_2_3_7 from GMS to WSN	[redacted]
2029	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2030	Series compensation of 5L91 and 5L98	[redacted]
2032	500 kV circuit 5L46 between KLY and Cheekye	[redacted]
2039	500kV circuit 5L14 between WSN and KLY	[redacted]

SHORTNAME **Portfolio B2: C+T**	*Description* Other clean and thermal resources (partial gas bridging)	***Portfolio Code*** **MKM_1NT_2N0_**[redacted]

Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	[redacted]
Wind_PC21	Wind	2024	99	371	
Wind_PC28	Wind	2024	153	591	
MSW2_LM	Municipal Solid Waste	2024	25	208	
Wind_PC19	Wind	2025	117	441	
Wind_PC13	Wind	2027	135	541	
Wind_PC10	Wind	2029	297	1023	
Wind_PC16	Wind	2030	99	377	
Wind_PC14	Wind	2031	144	527	
MSW1_VI	Municipal Solid Waste	2031	12	100	
Wind_VI12	Wind	2032	48	150	
Wind_PC15	Wind	2033	108	382	
WBBio_VI	Biomass	2033	30	239	
Run of River LM 80_100	Run of River Hydro	2033	62	223	
WBBio_LM	Biomass	2033	30	239	
Wind_PC09	Wind	2034	207	713	
Wind_PC20	Wind	2034	159	610	
Wind_PC11	Wind	2035	126	473	
Wind_PC41	Wind	2035	45	155	
Wind_PC42	Wind	2035	63	219	
Wind_PC18	Wind	2036	138	486	
Wind_PC26	Wind	2037	126	416	
Wind_PC48	Wind	2037	152	505	
Run of River KN 90_100	Run of River Hydro	2037	72	221	
Run of River VI 100_110	Run of River Hydro	2038	119	451	
Wind_VI13	Wind	2038	35	106	
Run of River LM 100_110	Run of River Hydro	2038	102	330	
Wind_PC06	Wind	2039	243	761	
Wind_VI15	Wind	2039	41	124	
WBBio_MAC	Biomass	2040	33	263	

Capacity Resources Required for Portfolio B2					
Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Cost of Capacity ($/kW-[redacted]
50 MW SCGT PR	Natural Gas	2018	50	394	[redacted]
100 MW SCGT NC	Natural Gas	2019	412	600	[redacted]
50 MW SCGT PR	Natural Gas	2020	50	394	[redacted]
GMS Units 1-5 Cap Increase	Resource Smart	2023	220	0	[redacted]
100 MW SCGT KN	Natural Gas	2023	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2024	206	300	[redacted]
100 MW SCGT KN	Natural Gas	2026	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2027	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2028	103	150	[redacted]
Revelstoke Unit 6	Resource Smart	2029	500	26	[redacted]
100 MW SCGT KN	Natural Gas	2031	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2032	103	150	[redacted]
100 MW SCGT KN	Natural Gas	2033	103	150	[redacted]
1000 MW PS_LM	Natural Gas	2034	1000	0	[redacted]
100 MW SCGT KN	Natural Gas	2040	103	150	[redacted]

Transmission Required for Portfolio B2		
Year	Name	[redacted]
2028	Shunt compensation at NIC and MDN	
2029	Series compensation of 5L91 and 5L98	
2030	Shunt compensation at WSN KLY	
2034	Series compensation 5L1_2_3_7 from GMS to WSN	
2034	Series compensation 5L11_12_13 from WSN to KLY	
2039	500kV circuit 5L14 between WSN and KLY	
2040	500 kV circuit 5L46 between KLY and Cheekye	

SHORTNAME Portfolio C2: S+C		*Description* Site C + Other clean resources (partial gas bridging)		*Portfolio Code* MKM_1LC_2N[redacted]	
Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	[redacted]
Site C	Large Hydro	2023	1100	5100	[redacted]

MSW2_LM		2031	25	208	[redacted]
Wind_PC19		2032	117	441	[redacted]
Wind_PC10		2033	297	1023	[redacted]
Wind_PC28		2033	153	591	[redacted]
Wind_VI14		2033	35	114	[redacted]
MSW1_VI		2033	12	100	[redacted]
WBBio_VI		2033	30	239	[redacted]
ROR_LM_80-100		2033	62	223	[redacted]
WBBio_LM		2033	30	239	[redacted]
Wind_PC13		2035	135	541	[redacted]
Wind_PC21		2035	99	371	[redacted]
Wind_PC14		2036	144	527	[redacted]
Wind_PC16		2037	99	377	[redacted]
Wind_PC20		2037	159	610	[redacted]
Wind_PC15		2038	108	382	[redacted]
Wind_PC41		2038	45	155	[redacted]
Wind_PC42		2038	63	219	[redacted]
Wind_PC09		2039	207	713	[redacted]
Wind_PC18		2039	138	486	[redacted]
WBBio_WK		2039	33	263	[redacted]
Wind_PC11		2040	126	473	[redacted]
ROR_KN_90-100		2040	72	221	[redacted]

Capacity Resources Required for Portfolio C2					
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	**Unit Cost of Capacity ($/kW-y**[redacted]
50 MW SCGT PR		2018	50	394	[redacted]
100 MW SCGT NC		2019	412	600	[redacted]
50 MW SCGT PR		2020	50	394	[redacted]
GMS Units 1-5 Cap Increase		2029	220	0	[redacted]
Revelstoke Unit 6		2030	500	26	[redacted]
1000 MW PS_LM		2034	1000	0	[redacted]
1000 MW PS_LM		2040	1000	0	[redacted]

Transmission Required for Portfolio C2		[redacted]
Year	**Name**	
2023	Series compensation 5L1_1_3-7 from GMS to WSN	
2023	Series compensation 5L11_12_13 from WSN to KLY	
2028	Shunt compensation at NIC and MDN	
2029	Shunt compensation at WSN KLY	
2030	Series compensation of 5L91 and 5L98	
2037	500kV circuit 5L14 between WSN and KLY	
2039	500kV circuit 5L8 between GMS and WSN	

SHORTNAME **Portfolio D2: C**	*Description* Other clean resources (partial gas bridging)			***Portfolio Code*** **MKM_1NC_2N0_**[redacted]	
Resource Name	**Type**	**In-Service Date**	**Installed Capacity (MW)**	**Average Annual Energy (GWh)**	[redacted]
Wind_PC13		2023	135	541	[redacted]
Wind_PC21		2023	99	371	[redacted]
Wind_PC28		2023	153	591	[redacted]
MSW2_LM		2023	25	208	[redacted]
Wind_PC19		2025	117	441	[redacted]
Wind_PC16		2026	99	377	[redacted]
MSW1_VI		2027	12	100	[redacted]
WBBio_VI		2027	30	239	[redacted]
Wind_PC10		2028	297	1023	[redacted]
Wind_PC14		2028	144	527	[redacted]
Wind_PC15		2028	108	382	[redacted]
Wind_PC20		2030	159	610	[redacted]
Wind_PC09		2031	207	713	[redacted]
Wind_PC41		2032	45	155	[redacted]
ROR_LM_80-100		2032	62	223	[redacted]
Wind_PC11		2033	126	473	[redacted]
Wind_PC18		2033	138	486	[redacted]
Wind_PC26		2034	126	416	[redacted]
Wind_PC42		2034	63	219	[redacted]
Wind_VI12		2034	48	150	[redacted]
Wind_PC48		2035	152	505	[redacted]
Wind_VI13		2035	35	106	[redacted]
Wind_VI14		2035	35	114	[redacted]
Wind_VI15		2035	41	124	[redacted]
WBBio_LM		2035	30	239	[redacted]
Wind_PC06		2036	243	761	[redacted]
ROR_LM_100-110		2036	102	330	[redacted]
Wind_NC09		2037	334	1026	[redacted]
Wind_PC27		2038	110	332	[redacted]
ROR_VI_100-110		2038	119	451	[redacted]
Wind_PC40		2039	117	349	[redacted]
Wind_SI12		2039	186	544	[redacted]
Wind_SI23		2040	193	569	[redacted]

Capacity Resources Required for Portfolio D2					
Resource Name	Type	In-Service Date	Installed Capacity (MW)	Average Annual Energy (GWh)	Unit Cost of Capacity ($/kW- [redacted]
50 MW SCGT PR		2018	50	394	[redacted]
100 MW SCGT NC		2019	412	600	[redacted]
50 MW SCGT PR		2020	50	394	[redacted]
Revelstoke Unit 6		2023	500	26	[redacted]
GMS Units 1-5 Cap Increase		2024	220	0	[redacted]
1000 MW PS_LM		2029	1000	0	[redacted]
1000 MW PS_LM		2036	1000	0	[redacted]

Transmission Required for Portfolio D2		
Year	Name	[redacted]
2023	Series compensation of 5L91 and 5L98	[redacted]
2028	Series compensation 5L1_1_3-7 from GMS to WSN	[redacted]
2028	Series compensation 5L11_12_13 from WSN to KLY	[redacted]
2033	Shunt compensation at WSN KLY	[redacted]
2036	500kV circuit 5L14 between WSN and KLY	[redacted]

APPENDIX E2 – SENSITIVITY ANALYSIS

1. Overview

This appendix provides a summary of the sensitivity analysis undertaken in the 2013 IRP and Site C environmental assessment process to test the cost-effectiveness of Site C against alternative resources in a range of potential future scenarios.

In this analysis, the cost-effectiveness of Site C is tested for two in-service dates (F2024 and F2026) under the following conditions:

1. Large- and small-gap electricity demand;
2. High and low electricity spot market price scenarios;
3. A lower cost of capital assumption for IPP projects;
4. Higher capital costs for Site C and/or IPPs; and
5. Compound sensitivities combining more than one of the above.

Sensitivity analysis typically involves varying one input at a time. By creating a given set of scenarios, BC Hydro can determine how changes in one variable will impact the base assumption/conditions established in the Site C EIS and the IRP. The sensitivity analysis was conducted around the base case scenarios described in the business case as summarized in Table 1.

Table 1: Base Case Analysis
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	In-Service Date	Base (Mid-Gap) Case *(~80% likelihood)*	Base Case with Expected LNG
Clean Portfolio	F2024	[redacted]	[redacted]
	F2026	[redacted]	[redacted]
Clean + Thermal Portfolio	F2024	[redacted]	[redacted]
	F2026	[redacted]	[redacted]

NOTE 1: The benefits for Site C are expected to be higher than the Clean Portfolio with Site C in-service in F2024.
NOTE 2: The benefits for Site C are expected to be higher than the Clean + Thermal Portfolio with Site C in-service in F2024.

As the sensitivity analysis was originally undertaken for the Site C EIS process, most analysis was conducted under the No LNG scenario. It is generally assumed that similar sensitivities would apply around the scenario with expected LNG.

The detailed sensitivity analysis has been used to provide an overview of some key sensitivity factors, as shown in Table 2.

Table 2: Sensitivity "Rules of Thumb"
Effect on Base Case PV of Differential (positive indicates increased benefits of Site C), $F2013 millions

Input Variable	Change in Variable	Effect on PV Benefit of Site C ($M)	
		Clean	Clean + Thermal
Difference in WACC between BC Hydro and IPPs	-1%	-210	-130
Wind Integration Cost	+1$/MWh	+19	+13
Site C Capital Cost	+1%	-24	-24
IPP Capital Cost	+1%	+23	+17
Long-term Electricity Market Prices	+1$/MWh	+15	+23

2. Large and Small LRB Gap Conditions

The gap between supply and demand affects the economic analysis of alternatives because it determines the level of short-term surplus created by Site C and the alternative portfolios as they come into service. BC Hydro uses its mid-load forecast of both energy and capacity requirements for the purposes of determining the need for new resources. The mid-level load forecast represents the expected future load, in which actual realized loads will be higher than forecast 50% of the time and lower than forecast 50% of the time.

BC Hydro addresses load forecast uncertainty by developing a high forecast band with approximately a 10 per cent exceedance probability (referred to as a high load forecast) and a low forecast band with approximately a 90 per cent exceedance probability (referred to as a low load forecast). These high and low bands are used in the large and small gap sensitivity analysis described in this section.

Another base assumption for the Site C need analysis is that the DSM target will deliver 7,800 GWh/year of energy savings and 1,400 MW of associated capacity savings. However the DSM target is aggressive and entails delivery risks. Precise forecasting of DSM savings for long-term planning purposes is challenging for several reasons, including:

- Limited experience with respect to targeting cumulative savings above current levels;
- Difficulty in distinguishing between load growth and DSM effects;
- Difficulty linking customer response to DSM actions, and forecasting the timing and efficacy of regulatory changes;
- Difficulty of incenting customer behaviour changes in a low-cost electricity jurisdiction.

In this analysis, the cost competitiveness of Site C is tested under 'large gap' and 'small gap' conditions (both assuming no LNG load):

- Large gap conditions are defined as high load forecast with low level of DSM savings (5,400 GWh/year compared to the target level DSM savings of 7,800 GWh/year);
- Small gap conditions are defined as low load forecast and low level of DSM savings. As discussed below, a reduced load forecast impacts DSM economic potential.

LNG Scenarios

- LNG proponents have the choice to self-serve or request service from BC Hydro. Should LNG load be supplied by BC Hydro, the benefits of the portfolio with Site C are expected to increase. This is because LNG load advances the need for new energy resources.

Table 3 summarizes the change in PV benefits for portfolios with Site C over portfolios without the project under these conditions. The PV benefits of Site C increase with the size of the gap. Site C is at a cost disadvantage to alternative portfolios in the small gap conditions due to its large size; however, the small gap scenario has almost no load growth after DSM for most of the 30-year planning horizon and is therefore unlikely.

Table 3: Change in Project Benefit due to Electricity Gap Condition
Effect on Base Case PV of Differential (positive indicates increased benefits of Site C), $F2013 millions

	In-Service Date	Large-Gap (~10% likelihood)	Small-Gap (~10% likelihood)
Clean Portfolio	F2024	See Note 1	-1,670
	F2026		-1,585
Clean + Thermal Portfolio	F2024	+2,110	-1,430
	F2026	See Note 1	-1,300

NOTE 1: The benefits for Site C are expected to be higher than the Clean + Thermal Portfolio with Site C in-service in F2024.

3. Cost of Capital Differential

- The cost of capital affects the economic analysis of alternatives because it represents the cost of financing for projects developed by BC Hydro and IPPs.
- BC Hydro has a lower cost of capital than IPPs because it is an agent of the Crown. This means BC Hydro’s borrowing is guaranteed by the Province, which has a higher credit rating than IPP developers. In its decision on the 2006 IEP/LTAP the BCUC found that IPPs’ cost of debt is higher than BC Hydro’s.[1].
- The base assumption for the WACC is 5 per cent for BC Hydro and 7 per cent for clean or renewable IPPs. A sensitivity test was performed assuming 6 per cent WACC for IPPs, effectively reducing the cost of capital differential between BC Hydro and IPPs from 2 per cent to 1 per cent.
- In this sensitivity test, the Site C portfolio maintains a cost advantage, although the benefit of the Site C portfolio is reduced from $630 million to $420 million for the Clean portfolio and from $150 million to $20 million for the Clean + Thermal portfolio, as shown in Table 4.

[1] *In the Matter of British Columbia Hydro and Power Authority: 2006 Integrated Electricity Plan/Long-Term Acquisition Plan*, Decision, 11 May 2007, page 205. In addition, the third party review of BC Hydro’s alternatives assessment methodology found that BC Hydro had selected reasonable values for its own WACC and a representative IPP WACC; Refer to Appendix xx for a copy of the third party alternatives assessment methodology review.

Table 4: Sensitivity of Project Benefit to Cost of Capital Differential of 1%
Effect on Base Case PV of Differential (positive indicates increased benefits of Site C), $F2013 millions

	Cost of Capital	In-Service Date	Change in PV of Cost Advantage from Base Case
Clean Portfolio	6%	F2024	-210
		F2026	-210
Clean + Thermal Portfolio	6%	F2024	-130
		F2026	-155

4. Market Prices

- Market prices affect the economic analysis of alternatives because they affect the value of the short-term surplus created by Site C and the alternative portfolios. Higher market prices will mean the surplus has greater value.
- A sensitivity analysis was also done to test the benefits of Site C against various market scenarios. In its base assumptions (Market Scenario 1), which are used in the portfolio analysis in the amended EIS and IRP, BC Hydro used the Ventyx Spring 2012 market price forecast.
- Additional market scenarios were identified for sensitivity analysis in the IRP. This section shows the cost-effectiveness of Site C in a high market (Market Scenario 3), base-case market (Market Scenario 1), and a low market (Market Scenario 2) price scenario. These three market scenarios are the most likely with a combined likelihood of 95 per cent.[2]
- The PV benefits of Site C over the Clean and Clean + Thermal portfolios are shown in Table 5. In comparison to the base case of Market Scenario 1 (which projects a spot market price of $33/MWh in F2024), the benefits of the project are greater in the high market (with a projected spot market forecast of about [redacted] in F2024) and smaller in the low market scenario (with a projected spot market price of about [redacted]h in F2024).
- In the Market Scenario 2 low market sensitivity case[3] (a lower probability scenario with 20 per cent likelihood), the project is still more cost competitive than the Clean portfolio for both the F2024 and F2026 in-service date. It is marginally less cost-competitive than the Clean + Thermal Portfolio for the F2024 in-service date, and is more cost competitive than the Clean + Thermal Portfolio for a F2026 in-service date. In the F2024 in-service date case, lower gas prices favour the natural gas-fired alternative while the energy surplus that comes with the project in its early years is now sold at a lower market price.

---

2 It can also be noted that market prices are the primary way in which foreign exchange rates can influence the portfolio analysis – the market price scenarios used in this sensitivity analysis are sufficiently broad to also effectively cover potential fluctuations in exchange rates.

3 No GHG regulation and natural gas prices at $3 MMBTU (one million British Thermal Units) continue for the entire forecast period.

Value of Surplus Capacity

- It is important to note that BC Hydro has conservatively assigned no value to surplus capacity. However, surplus capacity has value. In the BCUC review of John Hart Generating Station Replacement Project, BC Hydro provided evidence that while the market value of capacity is uncertain because the current market in the region is illiquid, there is a range of market values of [redacted]-year to about [redacted]r, based on recent Bonneville Power Administration tariffs, transaction and market analysis. U.S. market access transmission constraints could reduce the market value of capacity to $37/kW-year for the low end of the market range. If a value was assigned to capacity, it would increase the value of the short-term surplus.

Table 5: Sensitivity of Project Benefit to Market Prices
Difference from Base Case in PV of Costs (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	In-Service Date	Scenario 3: High Market Prices *(15% likelihood)*	Scenario 2: Low Market Prices *(20% likelihood)*
Clean Portfolio	F2024	+200	-180
	F2026	+150	-125
Clean + Thermal Portfolio	F2024	+320	-240
	F2026	+265	-175

5. Project Capital Cost

- The capital costs (i.e., costs of construction) affect the economics of the analysis of alternatives because they affect the cost of the portfolios including these resources.
- The Site C project cost estimate is a Class 3 cost estimate. To test the sensitivity of Site C to capital costs, BC Hydro evaluated a set of portfolios with a higher capital cost for the project:
  - BC Hydro evaluated scenarios where the project's costs are increased by 10 per cent, 15 per cent and 30 per cent while the cost of all other alternatives remains constant. It is important to note that the scenario with a 30 per cent capital cost increase for Site C, when all other alternatives are held constant, is implausible but was completed in response to a request from the JRP as part of the environmental assessment process.
  - BC Hydro conducted a sensitivity analysis showing the cost-effectiveness of Site C in a scenario where both Site C and alternatives experience a 30 per cent increase in cost. This 30 per cent sensitivity is at the far end of the range of a Class 3 estimate. However, it is less than the far end of the range of the Class 4 and 5 estimates for alternative resource options. Given the lack of specific design and site information for the Class 4 and 5 alternatives it is possible the cost impacts for alternative resource options could be higher.

- Table 6 below summarizes the portfolio PV results of the capital cost sensitivity analysis. With the plus 10 per cent capital cost sensitivity, Site C (with an in-service date of F2026) remains more cost competitive than the Clean Portfolio and the Clean + Thermal Portfolio. With an in-service date of F2024, Site C is still more cost competitive than the Clean Portfolio, but is at a disadvantage to the Clean + Thermal Portfolio.

Table 6: Sensitivity of Project Benefit to Capital Cost Increase
Effect on Base Case PV of Differential (positive indicates increased benefits of Site C), $F2013 millions

	Clean Portfolios		**Clean + Thermal Portfolios**	
	F2024	F2026	F2024	F2026
Site C 10% Capital Cost Increase All other alternatives held constant	-270	-230	-270	-230
Site C 15% Capital Cost Increase All other alternatives held constant	-380	-320	-380	-320
Site C 30% Capital Cost Increase All other alternatives held constant	-730	-610	-730	-610
Site C 30% Capital Cost Increase and Alternative Resources 30% Increase	-30	+70	-210	-90

- BC Hydro is actively managing and monitoring project costs to ensure Site C is delivered within the budget mandate. BC Hydro also has an ongoing value engineering process to identify and pursue potential cost savings.

6. Compound Sensitivities

- In the previous analyses, BC Hydro systematically changed one variable at a time to see how that individual change would affect the cost-effectiveness of the project compared to alternatives. The analysis showed that the benefits of Site C are more sensitive to the electricity gap conditions than to any other sensitivity. The next largest sensitivities are the market price scenarios and Site C capital cost. BC Hydro conducted further analysis of the potential compound impacts of these main drivers to the cost-effectiveness of Site C.
- One of the main issues with compound sensitivity analysis is that, in practice, it is difficult to quantify how individual items fluctuate together. For example, while there is likely a strong correlation between a large gap and higher commodity and labour prices (which impact project cost), it is less certain how the large gap/small gap and high market price/low market price scenarios correlate. As a result, the starting point for combined sensitivities is to assume that each sensitivity is independent.
- To provide a robust range of sensitivity scenarios, BC Hydro evaluated the difference in PV costs between portfolios at the extremes of the potential future scenarios. Specifically:

- A "Compound Low" scenario, with a low-market condition (i.e., Market Scenario 2) and a small electricity gap condition, as well as a 10 per cent capital cost overrun..[4]
- A "Compound High" scenario, with a high-market condition (i.e., Market Scenario 3) and a large electricity gap condition, as well as a 10 per cent under-run on the project capital costs.

- These scenarios represent the far ends of the potential probability distribution and are highly unlikely. For example, the compound low scenario assumes negligible load growth for several decades, coupled with significant increases in costs of construction during the same period. It is highly unlikely that costs would be rising in an environment that has negligible economic growth. Table 7 summarizes the results of the compound sensitivity analysis.

Table 7: Compound Sensitivities for LRB Gap, Market Price and Site C Capital Cost
Effect on Base Case PV of Differential (positive indicates increased benefits of Site C), $F2013 millions

	Clean Portfolios		Clean + Thermal Portfolios	
	F2024	F2026	F2024	F2026
Compound Low Scenario Small Gap, Low Market Price (Scenario 2) 10% Site C Capital Cost Increase)	Note 1	Note 1	-2,150	-1,990
Compound High Scenario Large Gap, High Market Price (Scenario 3) 10% Site C Capital Cost Decrease	Note 1	Note 1	+2,460	Note 2

NOTES:
1. The difference in PV cost in this scenario is expected to be higher than the difference in PV cost in the Clean + Thermal portfolios for the same sensitivity.
2. The difference in PV cost in this scenario is expected to be higher than the difference in PV cost in the Clean + Thermal portfolio with a F2024 in-service date for the Site C project.

- As shown in Table 7, the results of the compound sensitivity analysis are consistent with the results of the large and small LRB gap sensitivity analysis. Due to the compounded effects of market price conditions and capital cost variation, the Compound Low scenario has lower portfolio PV benefits for the project compared to alternative portfolios than the small gap scenario (-2,000 vs. -1,280). Likewise, the Compound High scenario has higher portfolio PV benefits for the Project over alternative portfolios than the large gap scenario (+2,610 vs. 2,260).

7. Information Exchange with CEBC and Bookend Scenarios

CEBC retained London Economic International LLC (LEI) to provide an alternative view of the world in which IPPs would appear to be the better choice over building Site C. It is BC Hydro's view that the LEI analysis amounts to a bookend position by considering the outcomes if many

[4] The Compound Low contains the small electricity gap scenario, which is a low likelihood scenario that would effectively see neglig ble load growth after DSM for the relevant portion of the planning period (about 4,900 GWh net growth from F2014 to F2033 compared to 11,700 GWh of net growth under the mid load mid DSM reference case for the same time period).

of the input variables and assumptions are aligned based on an outcome of reducing Site C's value.

In the 2013 IRP, BC Hydro took a prudent utility approach to the input variables and as a result the IRP analysis represents a reasonable mid-range position. A true bookend scenario favorable for Site C would make several different assumptions. Using a still reasonable set but upper range of assumptions in terms of establishing Site C benefits, BC Hydro has developed a bookend position to contrast with the LEI report that increases the analysed benefit of Site C by [redacted].

In the 2013 IRP sensitivity analysis, the following variables were identified as the key ones that impact the portfolio PV differential for portfolios with and without Site C: WACC Differential; Discount Rate; Wind Integration Cost; Site C Capital Cost; IPP Capital Cost; Market Price. This section discusses for each variable the range of values that could be assumed and contrasts the selected values with those proposed by LEI.

7.1. WACC Differential

- BC Hydro undertook an economic analysis in the IRP and used what it believed to be the overall financial cost of BC Hydro and the WACC from its IPP intelligence.
- All of the future WACC estimates were done on a forecast debt cost for the next 10 years of 4.8% nominal. As a result, BC Hydro had a WACC of 5% real (using a 70/30 debt/equity ratio) and IPPs 7% real for a WACC Differential of 2%. BC Hydro also undertook a sensitivity on which the WACC Differential is reduced to 1%.
- LEI asserts that IPPs and BC Hydro should have identical WACCs at 6% and makes the following adjustments to arrive at the identical 6% WACC: (1) a 1% reduction in IPP costs due to current market conditions; and (2) a 1% increase in the BC Hydro WACC to account for potentially higher Site C capital costs.
- Alternatively, BC Hydro could have chosen to do its IRP PV analysis using the 100% debt financing that will actually be used for Site C.
- As a result, the range of WACC Differential could be from a low of 1% (LEI's BC Hydro WACC increase is dealt with in the discussion of Site C capital cost below) to 4% (3% real debt cost versus 7% for IPPs) with the IRP middle value of 2%.

7.2. Discount Rate

- Consistent with BCUC decisions and guidance documents,[5] BC Hydro assumed a 5% real discount rate based upon its overall WACC.
- LEI assumed an 8% discount rate citing a 1989 government document. Use of the 8% discount rate favours shorter-lived IPP assets such as wind resources (20-25 years).
- Based upon the intergenerational benefits of Site C, a lower (social) discount rate is arguably appropriate.[6] The range of discount rates could vary from 3%-8% with the IRP middle value of 5% (all rates in real terms).

[5] See, for example, the BCUC's *Utility System Extension Test Guidelines*, section 2.

7.3. Wind Integration Costs

- In the latest wind integration cost study, BC Hydro found that $10/MWh was a mid-value and the range that was tested in the IRP was $5-15/MWh. BC Hydro tested a $5/MWh wind integration cost sensitivity.
- LEI did not include any wind integration cost in its analysis.
- BC Hydro recognizes that the markets have reduced in cost in recent years and as such, it would not propose greater than $10/MWh as being realistic. The range for the cost then is $5-10/MWh with the IRP analysis done at $10/MWh.

7.4. Site C Capital Costs

- The Site C cost estimate has a Class 3 (-10/+15%) accuracy which includes a contingency provision. The overall estimate is P70.
- In comparison, the IPP cost estimates are generally a Class 4 or Class 5 and none of the sites have been ground truthed. As a result, the majority of the estimates are -10/+40%. It is expected that the upside risk of IPP costs is greater than the possibility of down side potential.
- LEI asserted that the Site C cost estimate was too low and needed to be adjusted up to reflect risk which amounted to a 15% increase (including sunk costs).
- Alternatively, BC Hydro could have chosen to analyse Site C on an equivalent basis as the IPPs by removing the contingency provision and using a neutral estimate. The cost range for Site C then could be 90-115% of the current cost estimate while the IRP used 100%.

7.5. IPP Capital Cost

- IPP capital costs were developed with the Resource Options Report process that included stakeholder and consultant input on values to be used in the analysis. This was updated in 2012 based upon IRP consultation feedback on recent wind cost reductions. The estimates are typically -10/+40% in accuracy, and have not been ground truthed.
- LEI used North America IPP cost estimates that do not account for British Columbia's location, rugged terrain and First Nation accommodation/permitting costs. LEI's price assumptions were a -35% decrease to the prices used in the IRP. LEI did not undertake any comparison to BC Hydro's prior acquisition process bid outcomes.
- Further, the LEI analysis results in UEC values substantially below prior acquisition process outcomes and below prices recently proposed by the IPP industry in B.C.
- Alternatively, BC Hydro could have used the last data that was seen in BC Hydro's prior acquisition processes with a perspective that such processes reflect costs in BC Hydro's service area and/or IPP bidding behaviour.

---

[6] There were suggestions that a social discount rate as low as 2% should be used to reflect the multi-generational benefits of Site C's 100 year life in the Site C Joint Review Panel hearings.

- The results from BC Hydro's last broadly-based power acquisition process – the 2010 Clean Power Call - were $135/MWh in 2013$ or an 8% increase over the IRP values. The cost range for IPPs then would be 65-108% of IRP data used.

7.6. Market Price

- A significant impact on the cost effectiveness of Site C is how much is recovered in the markets when Site C's energy is in surplus. BC Hydro developed low-mid-high forecasts of market prices under the current environmental policy. With the very low gas prices that have been seen in recent years, there is expected to be much more upside potential than downside potential.
- While LEI did not choose to address this variable, it is a valid uncertainty, particularly on the upside potential. While the mid-case market price forecast was [redacted]h levelized over 20 years, the high forecast was about [redacted]h higher at [redacted].

8. Conclusion

- The reference case analysis provides analysis of the cost-effectiveness of Site C under a reasonable set of assumptions that neither favors Site C nor IPPs.
- The sensitivity analysis reviewed the cost-effectiveness of Site C under a range of scenarios. This analysis showed that Site C provides benefits compared to alternatives not only in the reference case, but also in a wide range of potential scenarios.
- The sensitivity analysis confirms BC Hydro's conclusion that Site C is the preferred alternative to meet the identified need for energy and capacity within BC Hydro's planning period – the scenarios in which alternative portfolios provide benefits compared to the project are generally low-probability and are associated with long-term low load growth or market prices.
- Table 8 on the following page provides a summary table of the sensitivity analysis. While it is possible to construct additional sensitivity scenarios to those represented above, these scenarios will likely fall within the extreme bounds described in the Compound Sensitivity scenarios and would be expected to reach the same conclusion – that given the wide range of potential scenarios in which Site C provides benefits compared to alternatives, and given the low likelihood of the scenarios in which it does not, the project is the preferred resource option to meet BC Hydro's forecast customer demand.

Table 8: Sensitivity Analysis Summary ($F2013 millions)				
Difference from Base Case in PV of Costs (Portfolio without Site C minus Portfolio with Site C)	**Clean Portfolios**		**Clean + Thermal Portfolios**	
	F2024	F2026	F2024	F2026
Base Case without LNG Mid Gap, Mid-Market Price (Scenario 1), WACC Differential = 2%, Wind Integration Cost = $10/MWh	630	880	150	390
Base Case with expected LNG Mid Gap, Mid-Market Price (Scenario 1), WACC Differential = 2%, Wind Integration Cost = $10/MWh	1,850	N/A	1,260	N/A
Base Case with expected LNG, up to 300 MW market bridging with gas peakers on North Coast Mid Gap, Mid-Market Price (Scenario 1), WACC Differential = 2%, Wind Integration Cost = $10/MWh	1,500	N/A	890	N/A
Effect on Base Case PV Differentials of changes to inputs				
Large Gap	Note 1	Note 1	+2,110	Note 1
Small Gap	-1,670	-1,585	-1,430	(907)
High Market Price (Scenario 3)	+200	+150	+320	+265
Low Market Price (Scenario 2)	-180	-125	-240	-175
Site C Capital Cost +10% alternatives held constant	-270	-230	-270	-230
Site C Capital Cost +15%, alternatives held constant	-380	-320	-380	-320
Site C Capital Cost +30%, alternatives held constant	-730	-610	-730	-610
Site C and Alternatives Capital Cost +30%	-30	+70	-210	-90
WACC Differential of 1%	-210	-210	-130	-155
Wind Integration Cost ($15/MWh)	+90	Note 1	+70	Note 1
Wind Integration Cost ($5/MWh)	-100	Note 1	-60	Note 1
Compound Low Scenario (Small Gap, Low Market Price, 10% Site C Capital Cost Increase)	Note 1	Note 1	-2,150	-1,990
Compound High Scenario (Large Gap, High Market Price, 10% Site C Capital Cost Decrease)	Note 1	Note 1	+2,460	Note 1

NOTE: The benefit for Site C in this scenario is expected to be higher than the comparative portfolio for the same sensitivity.

APPENDIX F – BLOCK ANALYSIS

To facilitate a comparison of environmental and economic development attributes between the Project and alternatives, BC Hydro created "Blocks" of resources that would make up the Project's 5,100 GWh/year of energy and 1,100 MW of dependable capacity. The resources used to make up these blocks were guided by the output of the Portfolio Modelling analysis.

The blocks created were:

- Clean Generation Block, composed of clean or renewable energy resources with Revelstoke Unit 6, GMS Units 1-5, and pumped storage for required capacity
- Clean + Thermal Generation Block #1, composed of clean or renewable energy resources with Revelstoke Unit 6 and six 100 MW natural gas-fired SCGTs for required capacity
- Clean + Thermal Generation Block #2, composed of clean or renewable energy resources with Revelstoke Unit 6, GMS Units 1-5 and four 100 MW natural gas-fired SCGTs for required capacity

The following table provides a high-level description of the results of the Block Analysis. The tables following provide the composition of the Blocks and the detailed technical, financial, environmental and economic development attributes of the Blocks.

Table 1 – Summary of Block Analysis Attributes			
	Site C	**Clean Portfolio**	**Clean + Thermal (Block #2)**
Portfolio Composition	Site C 1,100 MW 5,100 GWh	5,500 GWh Clean IPPs (*Wind, Municipal Solid Waste, Biomass*) 500 MW Revelstoke 6 220 MW GMS Units 1-5 500 MW Pumped Storage	4,500 GWh Clean IPPs (*Wind, Municipal Solid Waste, Biomass*) 500 MW Revelstoke 6 220 MW GMS Units 1-5 400 MW SCGT
Energy: Clean or Renewable[1]	5,100 GWh	5,100 net GWh	4,500 GWh
Energy: Thermal[2]	0	0	600 GWh
Direct Capital Costs[3] *($billions)*	[redacted]	[redacted]	[redacted]
Operating Costs *($millions/year)*	[redacted]	[redacted]	[redacted]
Adjusted UEC[4] *($ / MWh)*	[redacted]	[redacted]	[redacted]
Fuel Price Risk	None	None	Low
Economic Life of Projects	70 years	20-30 years for IPPs 40-50 years for Rev 6 / GMS	20-30 years for IPPs 40-50 years for Rev 6 / GMS
Ability to Scale to Load Growth	Low	High	High
Operational GHG Emissions[5] *(t / yr)*	0	217,000	511,000
Air contaminants: NO_x *(t / yr, 000s)*	0	0.3	0.5
Air contaminants: CO *(t / yr, 000s)*	0	0	0.9
Construction Jobs[6]	44,200	33,000	22,000
Key Social License Risks	Reservoir Impacts	Rate Impacts	Rate Impacts, GHGs, Air Quality

* If alternative resources were pursued instead of Site C, there would be additional costs associated with the write-off of approximately $325 million in Site C sunk costs. This is not reflected in the capital costs for alternative resource options.

NOTES:

1. For reference, the amount of clean energy awarded through the Clean Power Call was 3,266 GWh/year (firm) or 4,051 GWh/year (total). Post-attrition, the firm energy amounts from the Clean Power Call decrease to about 2,350 GWh/year by F2018.
2. Natural gas-fired plants are assumed to be built outside of the Lower Mainland.
3. Capital costs are for physical works only, and exclude inflation and interest during construction for all resource options.
4. UEC values for the purposes of portfolio analysis are based on the project UECs of the mix of resource options at the point of interconnection, and adjusted to include transmission-related costs, wind integration costs, soft costs and costs of capacity backup, and exclude sunk costs. Note that Site C's UEC at the point of interconnection is $82/MWh (including the elimination of Tier 3 water rentals).
5. For the purposes of portfolio analysis, GHG and local air emissions are only shown for fuel combustion during operations.
6. Construction of Site C would create approximately 10,000 direct person-years of employment during construction, and approximately 33,000 direct and indirect jobs through all stages of development and construction.

Table 2A – Clean Generation Block Details and UEC Calculation

Clean Generation				
Project Name	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	[redacted]
Energy Costs				
MSW2_LM	25	211	90	
Wind_PC28		591	121	
Wind_PC21		371	123	
Wind_PC13		541	123	
MSW1_VI	12	101	123	
Wind_PC19		441	124	
Wind_PC16		377	126	
Wind_PC14		527	127	
Wind_PC10		1023	129	
Wind_PC15		382	130	
Wind_PC20		609	131	
Wind_VI12		151	131	
Wind_VI14		113	132	
REV6 Variable Costs (see note 1)	n/a	26	12	
GMS Variable Costs (see note 2)	n/a	0	0	
PS Variable Costs (see note 3)	n/a	(364)	19	
Weighted Average excluding capacity resources	n/a	n/a	**125**	
Weighted Average including capacity resources	n/a	n/a	**135**	
Sub-total	36	5100	n/a	
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	[redacted]
REV6 Fixed Costs	488	n/a	50	
GMS Fixed Costs	220	n/a	35	
PS Fixed Costs	500	n/a	124	
Sub-total	1208	n/a	78	
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	[redacted]
Total	1244	5100	**153**	

Note:

1. REV6 variable cost include variable OMA and water rentals.
2. GMS variable cost include variable OMA and water rentals.
3. Pumped Storage variable cost include variable OMA and water rentals. The cost of energy losses is included in the total cost of the clean resources that would be used to serve those losses.
4. UECs include a soft cost adder of 5%, wind integration cost where applicable, adjustment for time of delivery, a regional transmission cost adder of $6/MWh, and the cost of delivery to the lower mainland.

Table 2B – Clean + Thermal Block #1 Details and UEC Calculation

Clean + Thermal Generation (No GMS, 6 SCGTs)

Project Name	Dependable Capacity (MW)	Annual Firm/Effective Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	[redacted]
Energy Costs				[redacted]
MSW2_LM	25	211	90	[redacted]
Wind_PC28		591	121	[redacted]
Wind_PC21		371	123	[redacted]
Wind_PC13		541	123	[redacted]
MSW1_VI	12	101	123	[redacted]
Wind_PC19		441	124	[redacted]
Wind_PC16		377	126	[redacted]
Wind_PC14		527	127	[redacted]
Wind_PC15		382	130	[redacted]
Wind_PC20		609	131	[redacted]
REV6 Variable Costs (see note 1)	n/a	26	12	[redacted]
SCGT Variable Costs (see note 2)	n/a	924	66	[redacted]
Weighted Average excluding capacity resources	n/a	n/a	**124**	[redacted]
Weighted Average including capacity resources	n/a	n/a	**113**	[redacted]
Sub-total	36	5101	n/a	[redacted]
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	[redacted]
REV6 Fixed Costs	488	n/a	50	[redacted]
SCGT Fixed Costs	588	n/a	88	[redacted]
Sub-total	1076	n/a	71	[redacted]
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	[redacted]
Total	1112	5101	**128**	[redacted]

Note:

1. REV6 variable cost include variable OMA and water rentals.
2. SCGT variable costs include variable OMA, fuel cost and GHG cost.
3. UECs include a soft cost adder of 5%, wind integration cost where applicable, adjustment for time of delivery, a regional transmission cost adder of $6/MWh, and the cost of delivery to the lower mainland.

Table 2C – Clean + Thermal Block #2 Details and UEC Calculation

Clean + Thermal Generation (With GMS, 4 SCGTs)

Project Name	Dependable Capacity (MW)	Annual Firm/Effective Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	
Energy Costs				[redacted]
MSW2_LM	25	211	90	
Wind_PC28		591	121	
Wind_PC21		371	123	
Wind_PC13		541	123	
MSW1_VI	12	101	123	
Wind_PC19		441	124	
Wind_PC16		377	126	
Wind_PC14		527	127	
Wind_VI14		113	132	
Wind_PC11		473	133	
Wind_PC09		713	133	
REV6 Variable Costs (see note 1)	n/a	26	12	
GMS Variable Costs (see note 2)	n/a	0	0	
SCGT Variable Costs (see note 3)	n/a	616	66	
Weighted Average excluding capacity resources	n/a	n/a	**125**	
Weighted Average including capacity resources	n/a	n/a	**117**	
Sub-total	36	5102	n/a	
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	[redacted]
REV6 Fixed Costs	488	n/a	50	
GMS Fixed Costs	220	n/a	35	
SCGT Fixed Costs	392	n/a	88	
Sub-total	1100	n/a	60	
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	
Total	1136	5102	**130**	

Note:

1. REV6 variable cost include variable OMA and water rentals.
2. GMS variable cost include variable OMA and water rentals.
3. SCGT variable costs include variable OMA, fuel cost and GHG cost.
4. UECs include a soft cost adder of 5%, wind integration cost where applicable, adjustment for time of delivery, a regional transmission cost adder of $6/MWh, and the cost of delivery to the lower mainland.

Table 3A –Financial Attributes

Attribute	Site C	Clean Block	Clean + Thermal	
			Block #1	Block #2
Construction Costs *($ billions, F2013 dollars)*	[redacted]			
Operating Costs *($ per year, F2013 dollars)*	[redacted]			
Adjusted Unit Energy Cost *($/MWh, F2013 dollars)*	[redacted]			

Table 3B – Environmental Attributes

Category	Indicator	Units	Classification	Clean Portfolio	Clean + Thermal (6 SCGT)	Clean + Thermal (4 SCGT)	Site C Portfolio
Land	Footprint	Hectares	n/a	2555	1768	2067	5661
	Net Primary productivity	ha per class	Low (0 to < 69)	31	23	37	0
			Medium (69 to < 369)	2080	1587	1756	2284
			High (> 369)	444	159	274	3377
	Remoteness – linear disturbance density (km/km2)	ha per class	Wilderness (< 0.2)	1104	643	903	3072
			Remote (0.2 to < 0.66)	219	148	194	478
			Rural (0.66 to 2.2)	779	521	603	1359
			Urban (> 2.2)	453	456	367	752
	High priority species count (percentile)	ha per class	0 to < 20	217	193	250	0
			20 to < 40	997	850	910	0
			40 to < 60	479	368	424	0
			60 to 80	316	58	128	0
			> 80	544	299	355	5661
Freshwater	Affected Stream Length	kilometers	n/a	0	0	0	123
	Priority fish species (number per watershed)	ha per class	No priority species (0)	0	0	0	0
			Low species diversity (1 to 12)	28	3	28	0
			Moderate species diversity (13 to 23)	2526	1764	2038	5661
			High species diversity (24 to 38)	0	0	0	0
	Reservoir Aquatic Area	Ha	n/a	0	0	0	9310
Marine	Valued ecological features	ha per class	None (0)	n/a	n/a	n/a	n/a
			Low (1 to 2)	0	0	0	0
			Medium (3 to 5)	0	0	0	0
			High (> 5)	0	0	0	0
	Key commercial bottom fishing areas	ha per class	No bottom fisheries	n/a	n/a	n/a	n/a
			1 bottom fishery	0	0	0	0
			2 to 3 bottom fisheries	0	0	0	0
			> 3 bottom fisheries	0	0	0	0
Atmosphere	GHG emissions	tonnes/year, thousands	Carbon dioxide equivalent	217	657	511	0
	Air contaminant emissions	tonnes/year, thousands	Sulphur dioxide	0.1	0.1	0.1	0
			Oxides of nitrogen	0.3	0.6	0.5	0.0
			Carbon monoxide	0.0	1.3	0.9	0.0
			Volatile organic compounds	0.0	0.0	0.0	0
			Fine particulates - PM2.5	0.0	0.0	0.0	0
			Fine particulates - PM10	0.0	0.0	0.0	0
			Fine particulates - PM total	0.0	0.0	0.0	0
			Mercury	0.0	0.0	0.0	0

Table 3C – Economic Development Attributes

Category	Indicator	Units	Classification	Clean Portfolio	Clean + Thermal (6 SCGT)	Clean + Thermal (4 SCGT)	Site C Portfolio
Provincial GDP	Construction period GDP	dollars, millions	Direct	469	306	319	792
			Indirect	1,670	1,069	1,133	2,336
			Induced	374	241	254	548
			Total	2,513	1,616	1,706	3,676
	Operations period GDP	dollars, millions per year	Direct	43	30	30	10
			Indirect	40	68	58	3
			Induced	15	14	14	2
Employment	Construction period employment	jobs	Direct	5,777	3,767	3,927	9,754
			Indirect	20,578	13,253	14,025	27,997
			Induced	4,434	2,852	3,012	6,497
			Total	30,788	19,872	20,963	44,249
	Operations period employment	jobs per year	Direct	315	275	277	25
			Indirect	510	542	517	29
			Induced	173	168	164	20
			Total	998	985	958	74
Provincial Government Revenue	Construction period revenue	dollars, millions	Direct	71	47	49	125
			Indirect	235	152	161	320
			Induced	49	32	34	72
	Operations period revenue	dollars, millions per year	Direct	29	23	24	4
			Indirect	6	10	8	0
			Induced	2	2	2	0

Note: Operations period revenue for Site C excludes water rentals of $35 million per year

APPENDIX G – COST OF SERVICE ANALYSIS

The comparative cost of service calculation is based on the portfolios established for the Portfolio Modelling undertaken for the IRP and Site C EIS. The four portfolios are:

1. Site C portfolio with other Clean resources
2. Clean Generation portfolio
3. Site C portfolio with other Clean + Thermal resources
4. Clean + Thermal portfolio

There are several major categories associated with the cost of service calculation. These are:

- The cost of service of BC Hydro resources, including the Project and/or BC Hydro growth projects such as Revelstoke Unit 6 and the GMS Units 1-5 Capacity Upgrade.
- The cost of service associated with the DSM target
- The cost of electricity purchased from IPPs including: clean and renewable IPPs, SCGTs for gas capacity and pumped storage; and
- System costs, specifically of costs and revenues associated with trade activity, transmission requirements, seasonal shaping and wind integration.

The cost of service analysis is done for incremental resources considered as part of the block analysis. The analysis excludes costs associated with actions that are common to all blocks (with the exception of the DSM target) and are therefore not relevant to the comparative analysis.

All values in this analysis are in nominal dollars unless noted otherwise.

Table 1 and Table 2 show the cost of service for the scenarios with the expected level of demand from Liquefied Natural Gas (LNG) customers. All of these scenarios have the same underlying load resource balance, but utilize different resources to meet the need for energy and capacity.

Figures 1-4 show the components of the cost of service for the four portfolios graphically.

Figure 5 shows a comparison of the total cost of service for the four portfolios. As shown, Site C provides substantially lower annual costs than the alternative portfolios in the period from 2030-2040, although the project does have slightly higher short-term costs due to the up-front capital investment.

Table 1 – Indicative Cost of Service for Clean Portfolios (Expected LNG)

(All values in Nominal Dollars)

Fiscal Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Site C + Clean Portfolio																				
BCH Projects	[redacted]																			
Site C																				
GMS Units 1-5																				
Revelstoke Unit 6																				
Total																				
IPP Resources																				
Clean Energy Resources																				
Clean Capacity Resources																				
Thermal Resources																				
Total																				
Demand-Side Management																				
System Costs																				
Transmission Costs																				
Firming & Shaping Adjustments																				
Market Import/Export																				
Total																				
Total Cost of Service																				
Clean Generation Portfolio																				
BCH Projects	[redacted]																			
Site C																				
GMS Units 1-5																				
Revelstoke Unit 6																				
Total																				
IPP Resources																				
Clean Energy Resources																				
Clean Capacity Resources																				
Thermal Resources																				
Total																				
Demand-Side Management																				
System Costs																				
Transmission Costs																				
Firming & Shaping Adjustments																				
Market Import/Export																				
Total																				
Total Cost of Service																				
DELTA (Site C minus Clean)																				

Table 2 – Indicative Cost of Service for Clean + Thermal Portfolios (Expected LNG)

(All values in Nominal Dollars)

Fiscal Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Site C + Clean + Thermal Portfolio	[redacted]																			
BCH Projects																				
Site C																				
GMS Units 1-5																				
Revelstoke Unit 6																				
Total																				
IPP Resources																				
Clean Energy Resources																				
Clean Capacity Resources																				
Thermal Resources																				
Total																				
Demand-Side Management																				
System Costs																				
Transmission Costs																				
Firming & Shaping Adjustments																				
Market Import/Export																				
Total																				
Total Cost of Service																				
Clean + Thermal Generation Portfolio																				
BCH Projects	[redacted]																			
Site C																				
GMS Units 1-5																				
Revelstoke Unit 6																				
Total																				
IPP Resources																				
Clean Energy Resources																				
Clean Capacity Resources																				
Thermal Resources																				
Total																				
Demand-Side Management																				
System Costs																				
Transmission Costs																				
Firming & Shaping Adjustments																				
Market Import/Export																				
Total																				
Total Cost of Service																				
DELTA (Site C minus Clean)																				

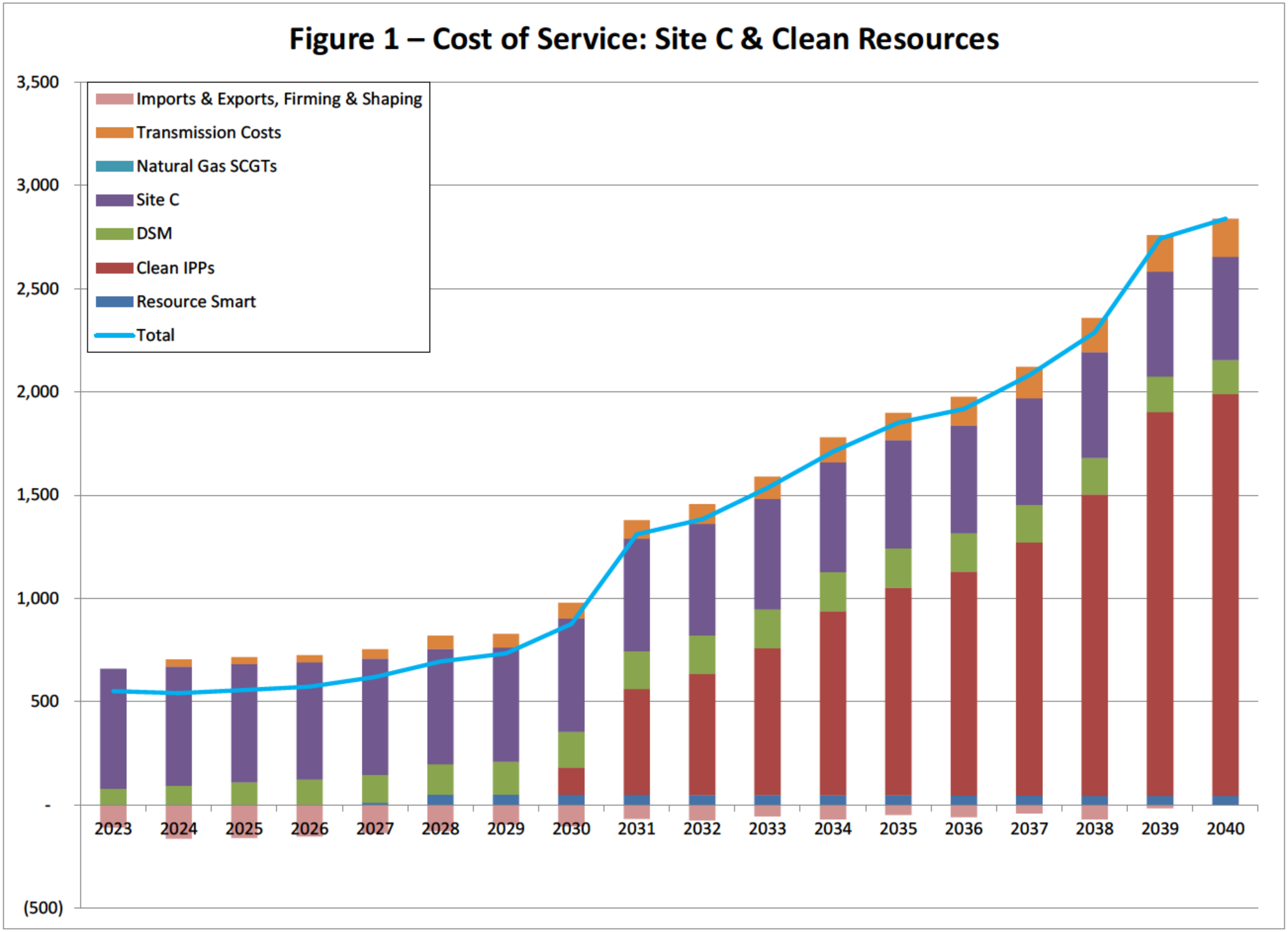


Figure 1 – Cost of Service: Site C & Clean Resources
3,500
3,000
2,500
2,000
1,500
1,000
500
-
(500)
Imports & Exports, Firming & Shaping
Transmission Costs
Natural Gas SCGTs
Site C
DSM
Clean IPPs
Resource Smart
Total
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040

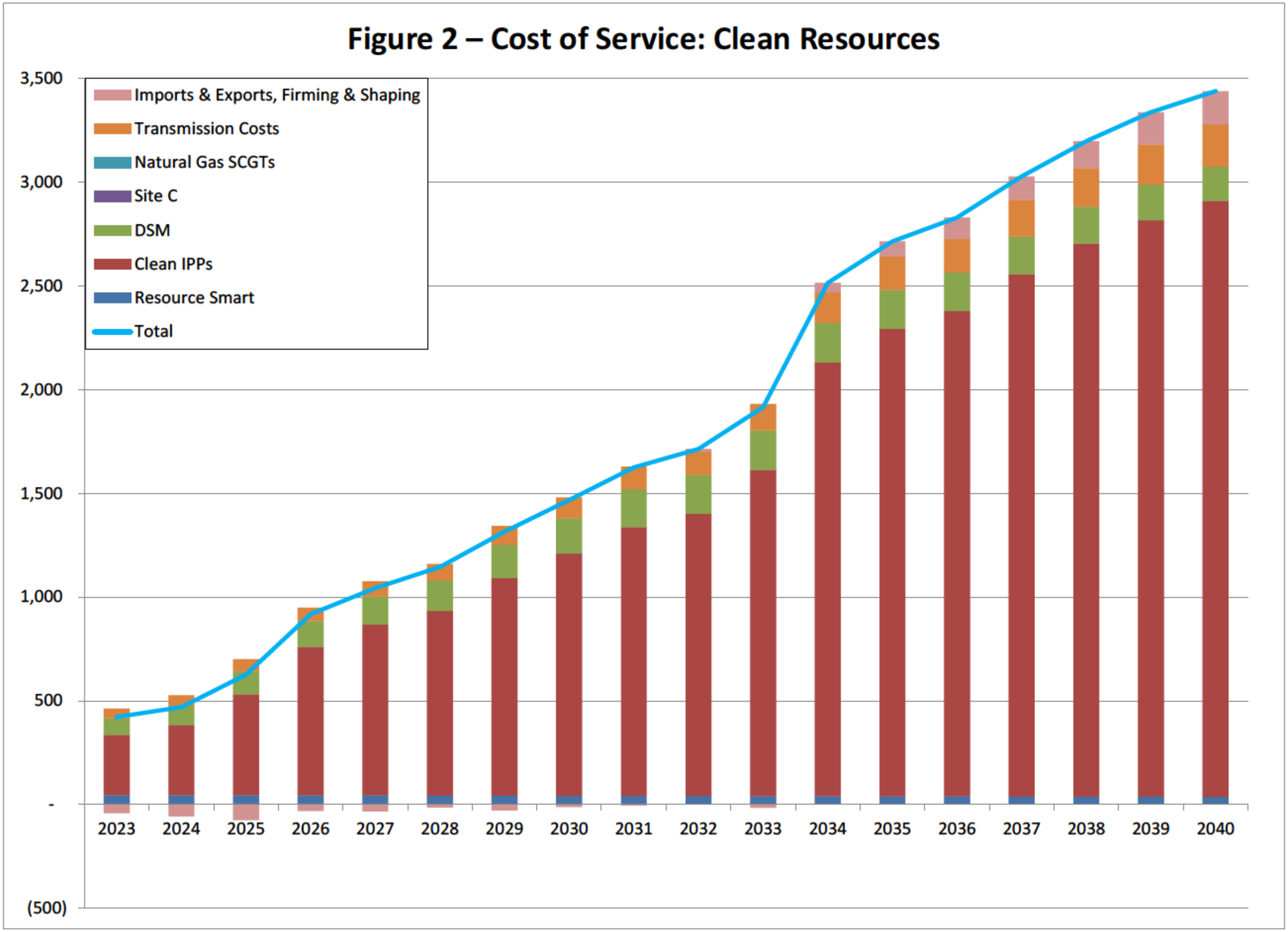


Figure 2 – Cost of Service: Clean Resources
3,500
3,000
2,500
2,000
1,500
1,000
500
-
(500)
Imports & Exports, Firming & Shaping
Transmission Costs
Natural Gas SCGTs
Site C
DSM
Clean IPPs
Resource Smart
Total
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040

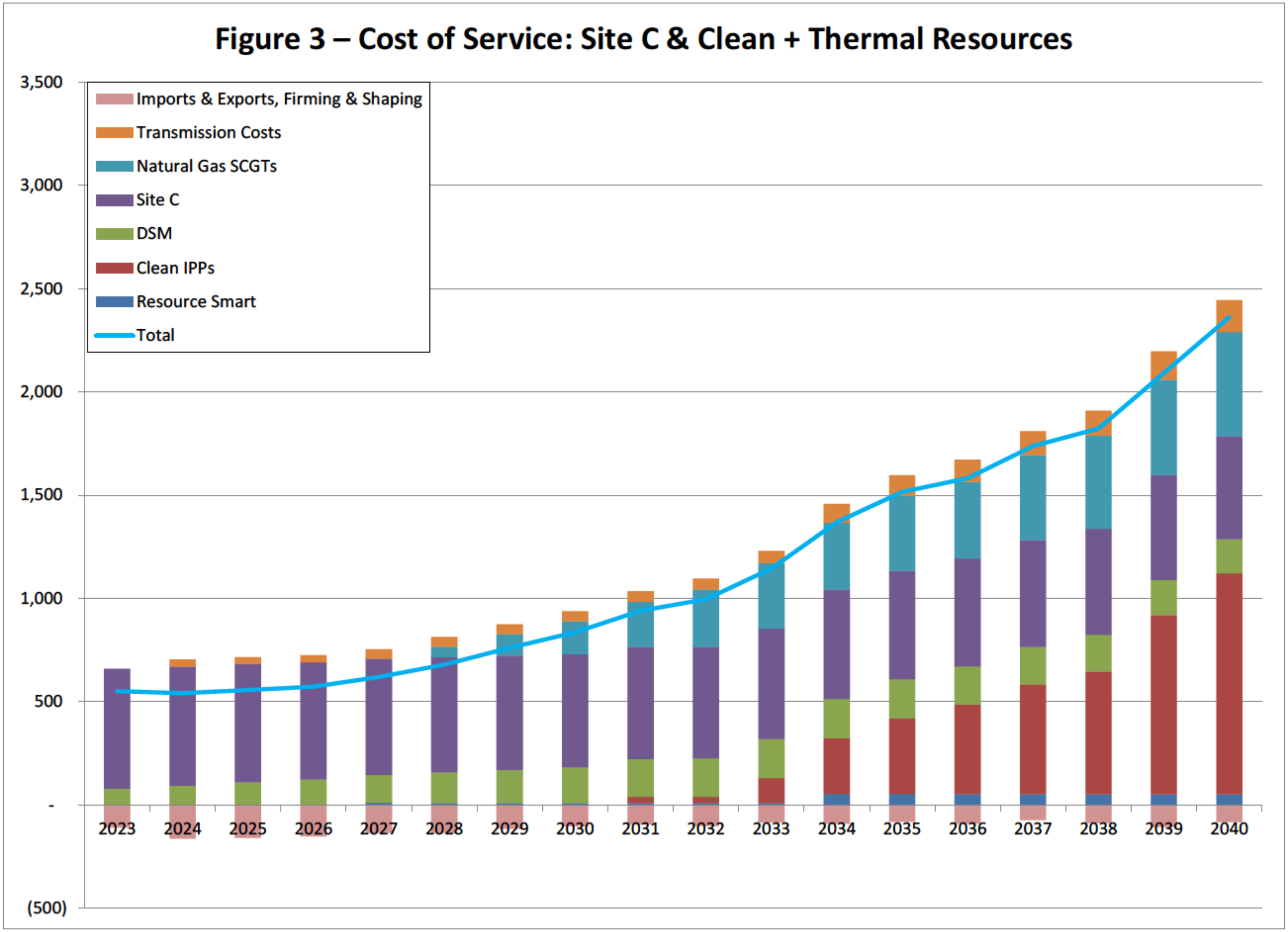


Figure 3 – Cost of Service: Site C & Clean + Thermal Resources
Imports & Exports, Firming & Shaping
Transmission Costs
Natural Gas SCGTs
Site C
DSM
Clean IPPs
Resource Smart
Total
3,500
3,000
2,500
2,000
1,500
1,000
500
-
(500)
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040

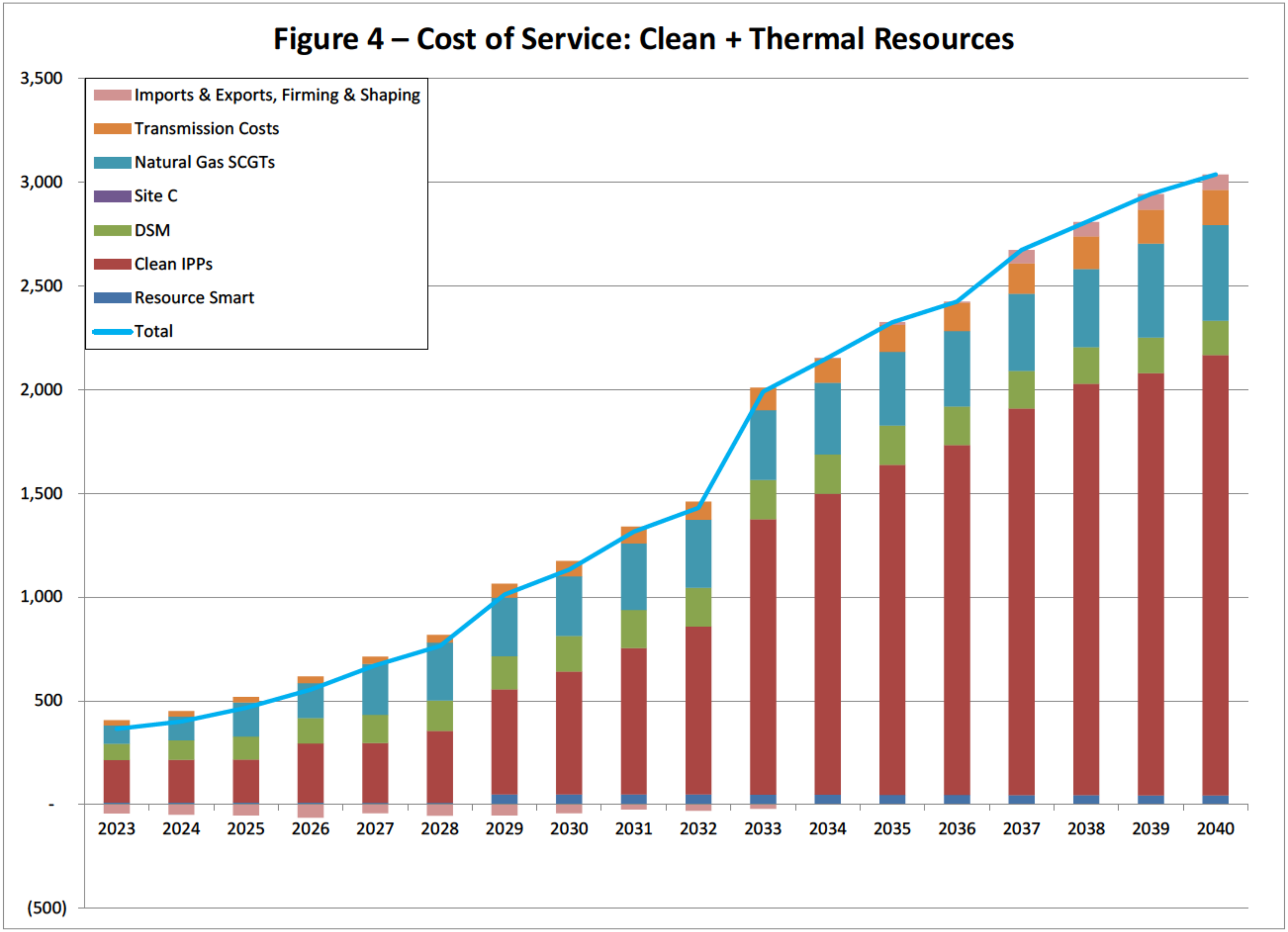


Figure 4 – Cost of Service: Clean + Thermal Resources
3,500
3,000
2,500
2,000
1,500
1,000
500
-
(500)
Imports & Exports, Firming & Shaping
Transmission Costs
Natural Gas SCGTs
Site C
DSM
Clean IPPs
Resource Smart
Total
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040

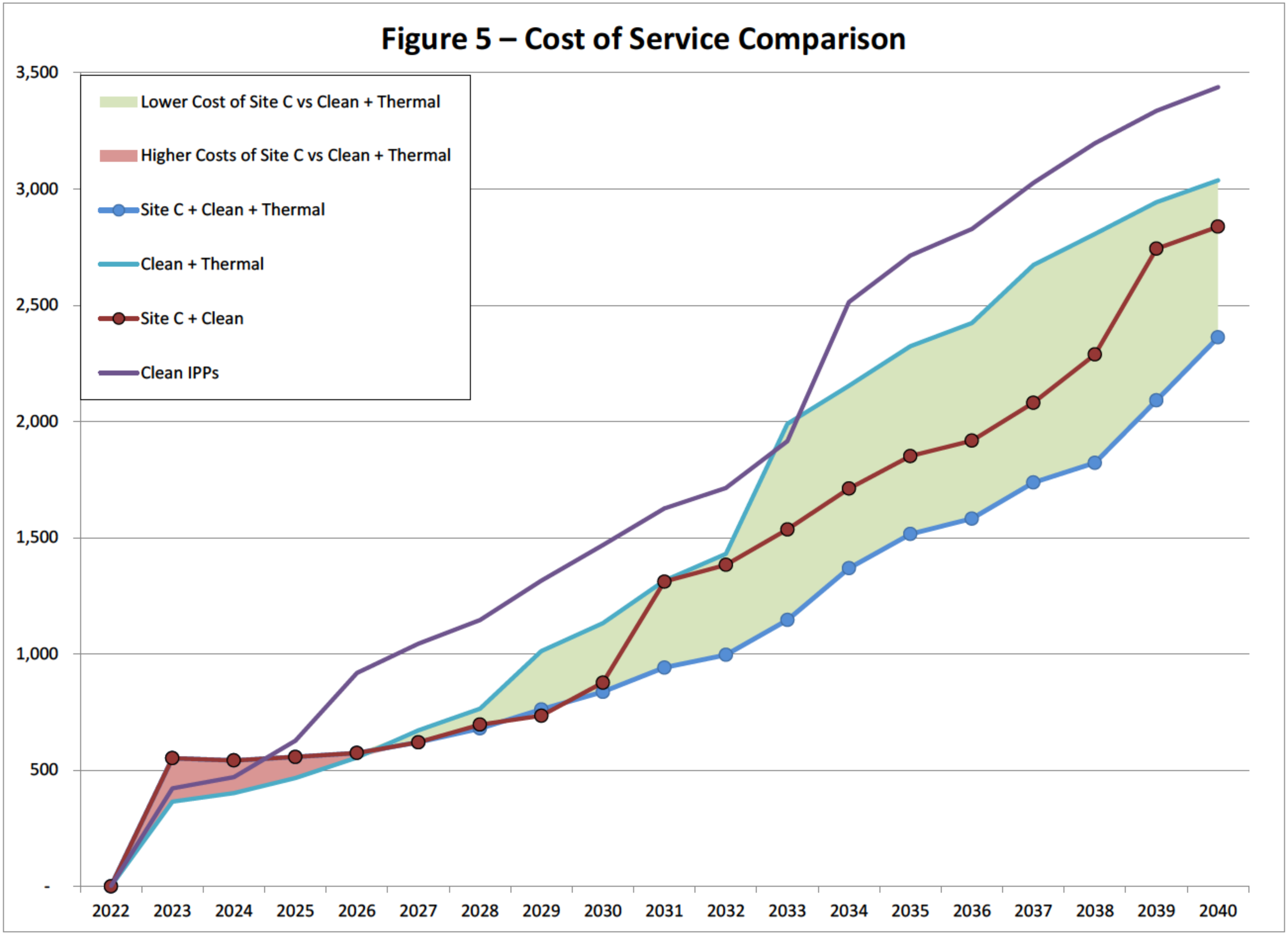


Figure 5 – Cost of Service Comparison
Lower Cost of Site C vs Clean + Thermal
Higher Costs of Site C vs Clean + Thermal
Site C + Clean + Thermal
Clean + Thermal
Site C + Clean
Clean IPPs
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040

APPENDIX H – DISPATCHABLE CAPACITY

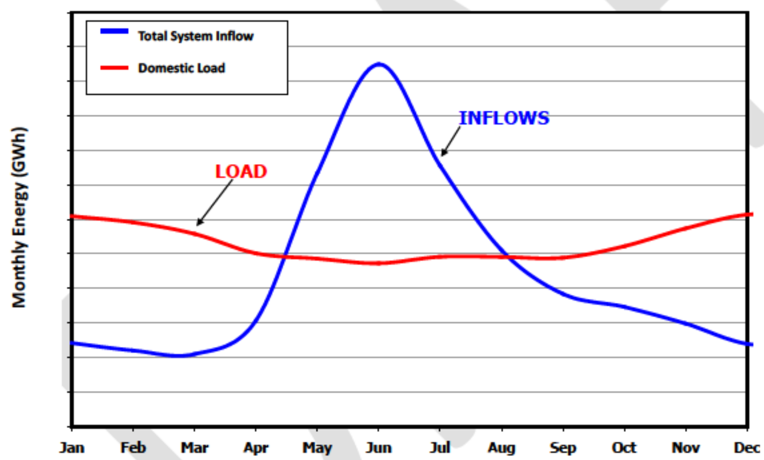
BC Hydro's major storage reservoirs (Williston and Kinbasket reservoirs) are valuable because they provide BC Hydro with dispatchable capacity. By storing water in the spring during peak flows, and using it in the winter during lower flows and higher demand, BC Hydro is able to meet the needs of its customers when electricity demand is at its highest. Site C would add to the value of Williston Reservoir by using the water a third time to generate electricity.

This appendix describes the reasoning behind the value of dispatchable capacity.

Hydroelectric Storage

- Electricity demand in British Columbia varies depending on the time of day, the days of the week, and the time of year. The highest (peak) seasonal demand occurs in the winter. As shown in Figure 1, water inflows to the BC Hydro reservoirs also vary, peaking in the spring with annual snowmelt and reaching a minimum in late winter.

Figure 1: BC Hydro System Load and Inflows



- Generation from run-of-river resources generally follows the inflow line on Figure 1. Generation from wind resources is generally flat on an average basis across the year (with a small increase in generation in winter), but fluctuates significantly on a daily, weekly, and monthly basis.

- As part of the normal operation of Williston Reservoir, water is stored during the high runoff and relatively low electricity price period from late April/May to early July. This makes water available to supplement the low runoff during the high demand and/or high price electricity periods in summer and winter. Williston Reservoir is able to store three years of water inflows. Flow from Williston Reservoir is regulated by the G.M. Shrum generating station located at the W.A.C. Bennett Dam. This flow then enters the Peace Canyon Dam's Dinosaur

Reservoir. The flow from Dinosaur Reservoir is then regulated by the Peace Canyon generating station.

- The flow into the proposed Site C reservoir would thus be regulated by the G.M. Shrum generating station and, to a lesser extent, the Peace Canyon generating station. In effect, this optimizes the value of the water stored behind W.A.C. Bennett Dam, as that water would be used for generation a third time.
- The Site C reservoir would have a maximum normal operating range of 1.8 metres and an active storage volume of 0.4 per cent of the active storage volume of Williston Reservoir. While this storage would not provide seasonal shaping, the upstream regulation allows Site C to match the timing of BC Hydro customer demand without the need to establish another large multi-year storage reservoir similar to Williston Reservoir.
- As a result, Site C would be able to produce approximately 35% of the energy produced by the G.M. Shrum generating station with 5% of the reservoir area.

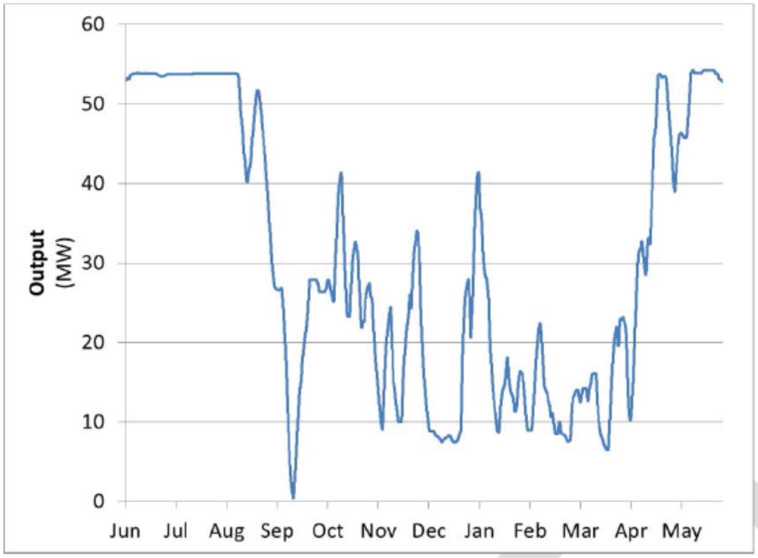
Integration of Clean or Renewable Resources

- An additional benefit of hydroelectric storage is the ability to integrate energy projects with low dependable capacity such as wind and run-of-river hydro.
- Many clean or renewable energy resources – such as wind or run-of-river hydro – are intermittent, as their generation varies with natural factors. To integrate these clean or renewable resources into the BC Hydro system, this variability must be backed up by dispatchable capacity.
- Site C provides additional clean and renewable dispatchable capacity to the BC Hydro system and increases the system's capability to integrate renewable resources such as run-of-river hydro and wind.

Variability of Run-of-River Projects

- With respect to the variability of run-of-river hydroelectric projects, run-of-river hydroelectric projects do not have any material amounts of storage, meaning that their output varies with the natural flow in the river.
- Typically, run-of-river projects generate at full output during the spring and early summer when river flows are high as well as during periods of heavy rain. Generation drops during low flow periods. Figure 2 shows the annual power output of a typical run-of-river project in the coastal region of B.C.
- The output from run-of-river projects is less predictable outside of the spring freshet, which makes it difficult to operate to match demand.

Figure 2: Sample Annual Output from a Run-of-River IPP



- The seasonal variability demonstrated in Figure 2 illustrates the potential benefits of hydro-electric storage to the integration of run-of-river resources. Generation from run-of-river resources generally peaks in the spring and early summer when customer demand is lowest.

- Facilities downstream of large hydroelectric storage reservoirs, such as Site C, can be operated to have lower generation during the spring and early summer, allowing run-of-river generation to be used to serve load as much as possible. Facilities like Site C can then be operated to have higher generation in the fall/winter when customer demand is highest (when run-of-river generation is low).

Variability of Wind Projects

- Due to natural variations in wind speed, wind power generation is highly variable in the short-term timescales of seconds to minutes. This results in the need for additional, highly-responsive generation capacity reserves on the electric system to maintain system reliability and security.
- The natural variability in wind power generation makes it difficult to forecast wind in the hour- to day-ahead time frame. This results in the need to set aside system flexibility to address the potential for wind generation to either under- or over-generate in this time frame.
- Figures 3 and 4 show BC Hydro load and wind generation variability from a sample eight-day period in June 2011 and January 2012, respectively.

Figure 3: Sample Wind Generation during Freshet Period (June 2011)

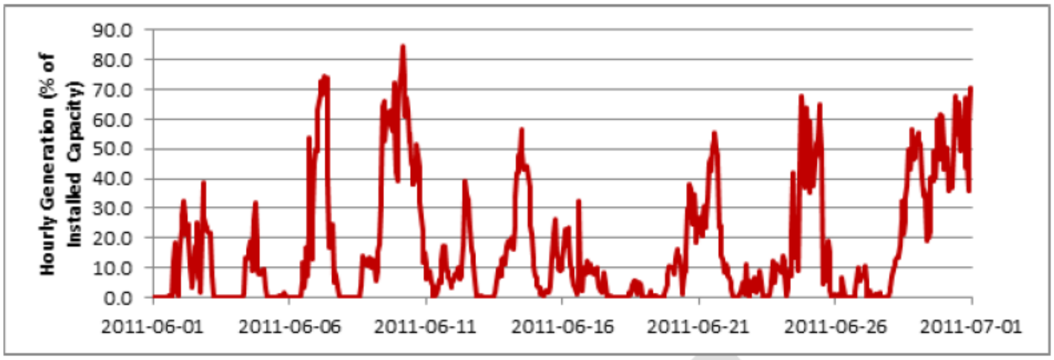
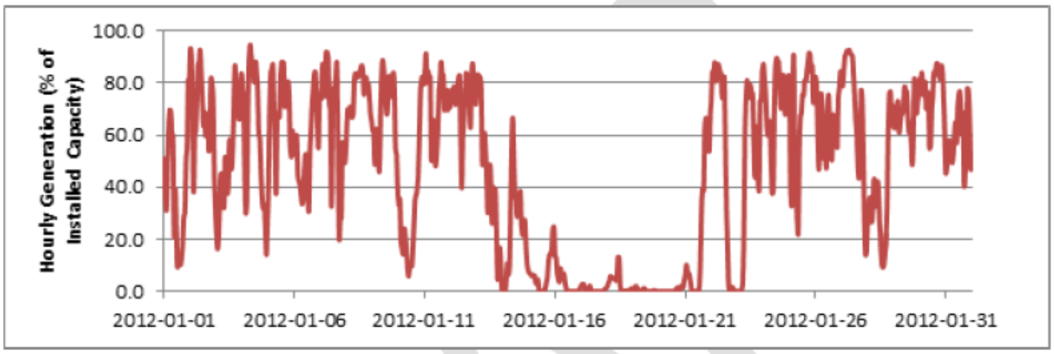


Figure 4: Sample Wind Generation during Winter (January 2012)



- To evaluate the potential benefits of the storage provided by Site C to integrating intermittent resources, BC Hydro conducted analysis of potential increases in wind integration limits as a result of Site C. The preliminary analysis showed that the wind integration limit could increase by up to 900 MW with the addition of Site C, without affecting system reliability and security.

Value of Economic Dispatch

- As discussed, generation from intermittent resources such as wind and run-of-river hydro is determined by environmental conditions such as river flows or wind speeds. As a result, intermittent resources cannot be economically dispatched in response to changes in market prices.
- In contrast, the Site C Environmental Impact Statement considered three sets of resources that are economically dispatchable: pumped storage, natural gas-fired generation and Site C. These projects can generate power when market pricing is high and stop generation when pricing is low, providing additional value to BC Hydro's ratepayers.

APPENDIX I-1 – CONSEQUENCES OF PROJECT DELAY OR HALT

Confidential

Available Upon Request

APPENDIX I-2 – ECONOMIC ANALYSIS OF PROJECT DELAY

Confidential
Available upon request

APPENDIX J – CONSIDERATION OF INPUT FROM FIRST NATIONS

Confidential

Available upon request

APPENDIX K – ADDITIONAL ANALYSIS TO SUPPORT PROVINCIAL INVESTMENT DECISION

Confidential

Available upon request