1.0 PROJECT NEED AND ALTERNATIVES

Summary

Demand for energy and capacity in B.C. is forecast to increase by approximately 40% over the next 20 years, not including load from LNG facilities. BC Hydro is planning to meet this need with a combination of Demand-Side Management (~50% of new supply), new and renewed IPP contracts (~30% of new supply), and the Site C project (~20% of new supply). After accounting for conservation measures and before load from LNG facilities, there is a need for new capacity in F2019 and energy in F2028. If expected load from LNG is included, it advances the need for energy to F2022. BC Hydro believes Site C is the preferred option to help meet this need.

1.1 Issue

- This briefing note describes how BC Hydro undertakes its long-term planning process that resulted in the Integrated Resource Plan (IRP) and the identification of Site C as a preferred part of the portfolios to meet future customer demand.

1.2 Background

- 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 within the provincial legal and policy context.
    - *Energy* is the amount of electricity produced or used over a period of time.
    - *Dependable Capacity* is the maximum amount of electricity that BC Hydro can supply to meet peak customer demand in the province at a point in time.
    - For instance, wind generation delivers energy, but no dependable capacity. Large hydro and natural gas provide both energy and dependable capacity.
- The key steps in BC Hydro's long-term planning process are:
    - The determination of expected future customer demand (the "Load Forecast").
    - The determination of what resources are available to BC Hydro, absent any new actions (the "Existing and Committed Supply").
    - The identification of actions that will be undertaken prior to any other, due to policy or cost reasons ("Baseline Actions").
    - The identification of which alternatives BC Hydro can rely on to meet the remaining gap between demand and supply ("Available Alternatives").
    - The creation of portfolios and analysis to determine the preferred alternatives to meet the remaining customer load ("Portfolio Analysis").

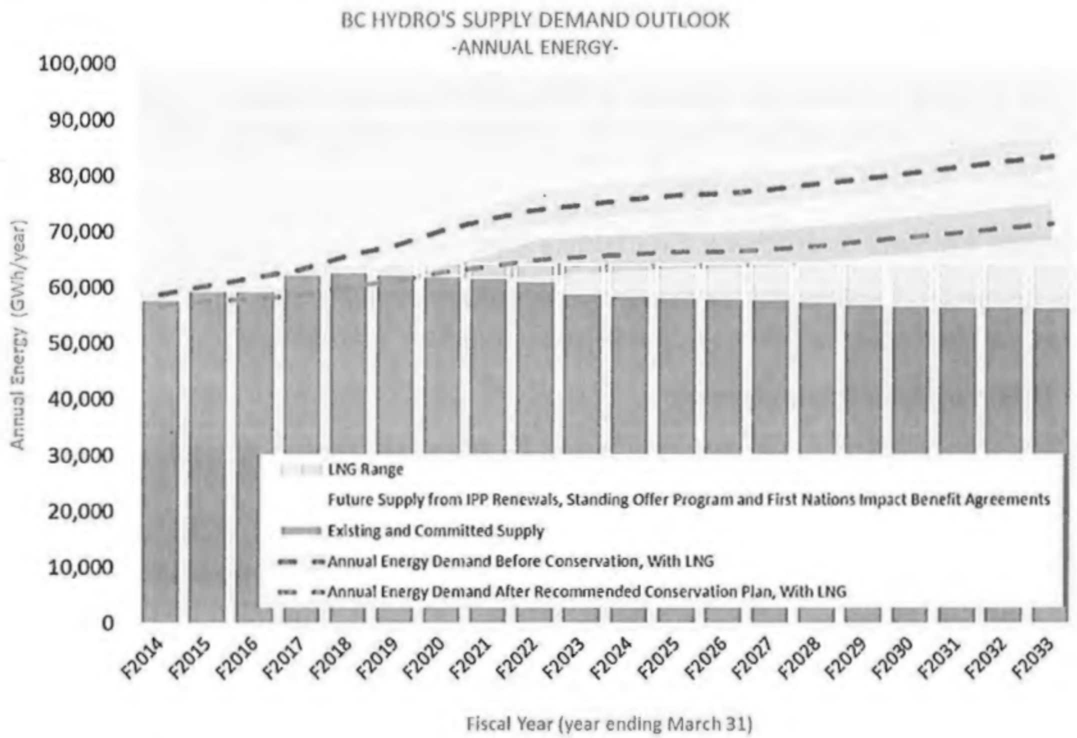
1.3 Load Forecast

- As part of fulfilling its obligation to meet the electricity needs of its customers, BC Hydro develops and regularly updates a long-term load forecast to project future energy and capacity requirements.
- 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.
- In addition, the August 2011 Government Review of BC Hydro found that *"BC Hydro's energy forecasting process is well planned and provides accurate, reliable forecasts. Each forecast receives multiple levels of review to ensure accuracy and completeness as well as being monitored on a month-to-month and quarterly basis."*
- With respect to the accuracy of the forecast, the current forecast was prepared in 2012 and tracked well within 1 per cent accuracy through F2014.
- Inputs to the long-term load forecast include economic drivers (e.g., GDP for commercial and industrial forecasts, population growth for residential forecast) and a production forecast for each major industrial customer. Many inputs are provided by external experts, and sector-specific experts for the forestry, mining, and oil and gas industries.
- BC Hydro's 2012 long-term load forecast projects that electricity demand in B.C. will increase by approximately 40% over the next 20 years excluding any load from LNG facilities and before accounting for DSM. If new LNG facilities request service from BC Hydro, this load growth will increase, as shown in Figure 1.
- After applying load reduction from DSM, BC Hydro projects a 1% growth in electricity demand per year. This is in line with other jurisdictions' assessments of their growing electricity needs.[1] 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.[2]

[1] Forecasted growth of 1% is in line with other North American forecasts such as the U.S. Energy Information Administration's Annual Energy Outlook and the 0.85% 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.

[2] Between 1989 (when DSM was introduced) and 2008, long-term load growth after DSM ranged from 1.5% to 2% per year.

Figure 1: BC Hydro's Energy Supply-Demand Outlook



1.4 Existing & Committed Supply

- Energy and capacity from BC Hydro's existing and committed resources are listed in Table 1. This supply includes BC Hydro's heritage hydroelectric resources and thermal resources, and Independent Power Producers (IPPs).
  - *Heritage Hydroelectric Resources:* By 2033, BC Hydro's 31 existing hydroelectric facilities are expected to supply approximately 48,500 GWh/year of energy and approximately 11,400 MW of capacity, which reflects planned upgrades to these facilities.[3] See Appendix 1H for planned and contemplated BC Hydro capital projects.
  - *Heritage Thermal Resources:* The Burrard Thermal and Prince Rupert Generating Stations are the only two BC Hydro-owned thermal generating stations that serve the integrated system. By 2033, these assets will supply only a modest amount of energy and capacity (180 GWh/year of energy and 46 MW of capacity).
  - *Existing and Committed IPP Supply:* As of January 1, 2014, BC Hydro manages 83 Energy Purchase Agreements (EPAs) for IPPs in commercial operation with an additional 44 EPAs for projects in the pre-commercial operation stage. According to the IRP, 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] This includes BC Hydro capital projects planned and underway, such as the Ruskin powerhouse upgrade, the John Hart Generating Station replacement and Mica Units 5 and 6.

Electricity from many IPPs is intermittent (i.e., not always available when required). As such, the amount of capacity that is dependable may be lower than stated. Further discussion regarding the importance of dependable capacity is provided in Appendix 1F.

- By 2033, the gap between BC Hydro's existing and committed supply and forecast load is approximately 23,800 GWh of energy and 4,500 MW capacity, without including any load from LNG.

1.5 Baseline Actions to Reduce Electricity Gap

- There are several actions that can be taken to reduce the electricity gap. The following actions are "first choices" before consideration of further alternatives.

1.5.1 Demand-Side Management

- BC Hydro plans to meet approximately 78% of its load growth through conservation and efficiency initiatives.
  - BC Hydro uses three main tools to achieve its DSM targets: codes and standards; rate structures aimed at conserving energy, promoting energy efficiency or reducing energy demand; 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% in F2021, well above the *Clean Energy Act* objective of at least 66%. Planning for higher levels of DSM instead of Site C would increase costs and increase deliverability risk.

→ 85% of capacity gap is DSM.

  - While BC Hydro is among the leading jurisdictions in DSM activity, as measured by DSM spending as a percent of retail sales, there are delivery risks. DSM requires customers to make behavioural changes that are difficult to implement in a low-rate jurisdiction like B.C. This uncertainty has been highlighted in recent evaluations of rate structures. This deliverability risk is shown by recent results in the Medium General Service (MGS) and Large General Service (LGS) conservation rate structures. These two rate structures are not delivering forecasted savings, and are showing lower savings of approximately 500 GWh last year.

what performance

  - Appendix 1G provides a review of BC Hydro's DSM activities compared to other jurisdictions.

1.5.2 IPP Options

- Once DSM is pushed to prudent limits, BC Hydro looks at supply side resources to fill the balance of the gap. Potential supply from IPP options beyond existing and committed IPPs is outlined in Table 1. These options include:
  - *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 of energy and 10 MW of capacity.

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- 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 targets, 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 F2028.**
- It is important to note that the addition of LNG load served by BC Hydro has the potential to significantly increase the need for new resources by 2033, as shown in Table 1.[4] Further discussion of the relationship between Site C and potential LNG electricity rates is provided in Appendix 1D.

Table 1: Summary of F2033 Load-Resource Balance

	Energy (GWh)	**Capacity** (MW)
Forecast Customer Load[5]	80,300	16,700
Existing and Committed Resources	56,500	12,100
New Resource Requirement (Gap)	**23,800**	**4,500**
New and Renewed IPPs	8,000	800
DSM[6]	11,900	2,200
Gap after IPPs and DSM (no LNG)	**3,900**	**1,700**
Gap with Low LNG	4,800	1,800
Gap with High LNG	10,500	2,500

NOTE: Numbers may not add up due to rounding.

[4] 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 gigawatt hours per year being an expected amount. This is based on some proponents using grid power for their ancillary needs (about 15-20% of total energy requirements), some generating their own power on site and others taking power for both compression and ancillary energy needs.

[5] Peak load includes BC Hydro's 14% planning reserve requirement.

[6] Includes demand reductions from SMI theft reduction and BC Hydro's Voltage Optimization project in addition to the DSM target.

1.6 Available Alternatives

- The Site C project is a source of 1,100 MW of dependable capacity and 5,100 GWh of energy/year. In coming to its recommendation of Site C as the preferred resource, BC Hydro considered several available resource options.
- Provincial policy, particularly the *Clean Energy Act* (CEA), provides context in terms of what alternatives are available to BC Hydro. While BC Hydro must plan within this context, a discussion of some alternatives (i.e., natural gas-fired generation beyond CEA's 93% clean or renewable target; and large hydro excluded by CEA) is provided in Appendices 1A and 1C.
- Alternatives that have been considered *within* the provincial legal and policy context include:

  Clean IPP Resources:

  - Wind (likely the primary IPP resource selected given recent price decreases)
  - Run-of-river hydro
  - Biomass
  - Municipal solid waste, both in Lower Mainland and on Vancouver Island
  - Pumped storage (for capacity)

  Thermal (natural gas-fired) IPP Resources:

  - Simple-Cycle Gas Turbines (SCGTs) provide peak capacity but are less efficient at generating energy than Combined Cycle Gas Turbines (CCGTs). SCGTs are currently more attractive due to their value in meeting winter peak demand within the 93% clean CEA objective.
  - CCGTs are more efficient than SCGTs and are typically used for base load energy, rather than peak capacity. CCGTs are less attractive within the 7% non-clean headroom of the CEA.

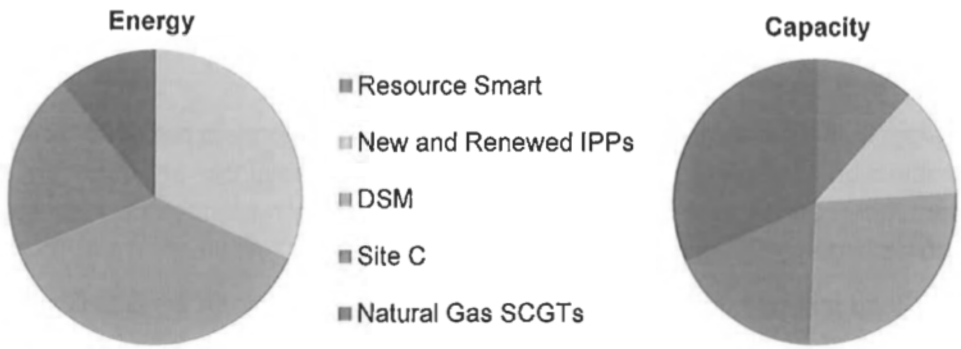
  Upgrades at BC Hydro Facilities (Resource Smart):

  - Addition of a sixth unit at Revelstoke for an additional 500 MW of capacity.
  - Upgrades to GMS units 1-5 for an additional 220 MW of capacity.

  DSM beyond target of 7,800 GWh/year (1,400 MW) by F2021 (i.e., DSM Option 3):

  - DSM Option 3 targets 8,300 GWh/year of energy savings (1,500 MW) by F2021 by undertaking more aggressive program activities.
- Figure 2 shows the breakdown of the resources that provide new energy and capacity in the Base Resource Plan with expected LNG. This includes both the baseline actions and the options selected as part of the analysis of alternatives.

Figure 2: Breakdown of New Resources in F2033 (scenario with expected LNG)



1.7 Portfolio Analysis

- Each of the above alternatives alone would not be enough to replace the energy and capacity from Site C. As such, BC Hydro developed several combinations (portfolios) of comparable energy and capacity resources.
  - *Site C Portfolios* include the Site C project.
  - *Clean Generation Portfolios* replaces Site C with a combination of clean IPP energy resources (e.g., wind, run-of-river and biomass) and clean capacity resources (e.g., Revelstoke 6, GMS units 1-5, and Pumped Storage)
  - *Clean + Thermal Generation Portfolios* replaces Site C with a combination of clean IPP energy resources (e.g., wind, run-of-river and biomass), and a mix of clean and thermal capacity resources (e.g., SCGTs, Revelstoke 6, and GMS units 1-5).
- BC Hydro also reviewed a portfolio including DSM Option 3 as an alternative to Site C. The key conclusions were that:
  - On its own, DSM Option 3 would defer the energy gap by one year, and does not defer the capacity gap. As a result, DSM Option 3 on its own is not an alternative to Site C.
  - When combined in a portfolio with other options (including gas-fired generation within the 93% clean target, Revelstoke Unit 6 and GMS Units 1-5), the portfolio including DSM Option 3 had a higher cost ($320 million more) than portfolios with Site C and the DSM Target.
- The Site C, Clean, and Clean + Thermal portfolios were then compared based their technical, financial, environmental, and economic development attributes.
- Appendix 1B provides a summary table of these and other important considerations, both within and outside of the current legal and policy context.

1.7.1 Technical Attributes

- The portfolios were constructed to have similar overall technical attributes (approximately 5,100 GWh of average annual energy and 1,100 MW of dependable capacity). However, some important differences include:
  - *Energy:* In the Clean and Clean + Thermal portfolios, energy is provided by a combination of clean or renewable resources. These resources are generally intermittent, and require additional dependable capacity resources from sources such as large hydro, pumped storage, or natural gas.

    The Clean portfolio requires about 400 GWh more energy than the Site C portfolio, due to energy losses of about 30% from pumped storage.
  - *Capacity:* Intermittent resources such as wind and run-of-river hydro provide energy, but provide very little, if any, dependable capacity.

    In the Clean portfolio, dependable capacity is provided by pumped storage, Revelstoke Unit 6 and GMS Units 1-5, with some biomass resources. In the Clean + Thermal portfolio, dependable capacity is primarily provided by SCGTs, Revelstoke Unit 6 and GMS Units 1-5, again with some biomass resources. Because both these portfolios rely significantly on intermittent resources, there may be additional firming and/or shaping capability required that is not included in the portfolio analysis.

1.7.2 Financial Attributes

- BC Hydro conducted two forms of financial analysis:
  - *Block Analysis:* Compares portfolios of resources that make up the same 5,100 GWh of energy and 1,100 MW of dependable capacity as Site C. It uses a block adjusted unit energy cost (UEC), representing the cost of energy delivered to the Lower Mainland.

    As an example, Site C has a UEC of $82/MWh at the point of interconnection (this reflects a $1/MWh reduction due to the elimination of Tier 3 water rental rates). The UEC is adjusted to include system transmission costs, exclude sunk costs, and account for the seasonal profile of generation. This results in the $91/MWh block adjusted UEC.
  - *Portfolio Modelling Analysis:* Uses a model that captures variability in the timing of resources, the effects of resources on the BC Hydro system, and trade benefits.

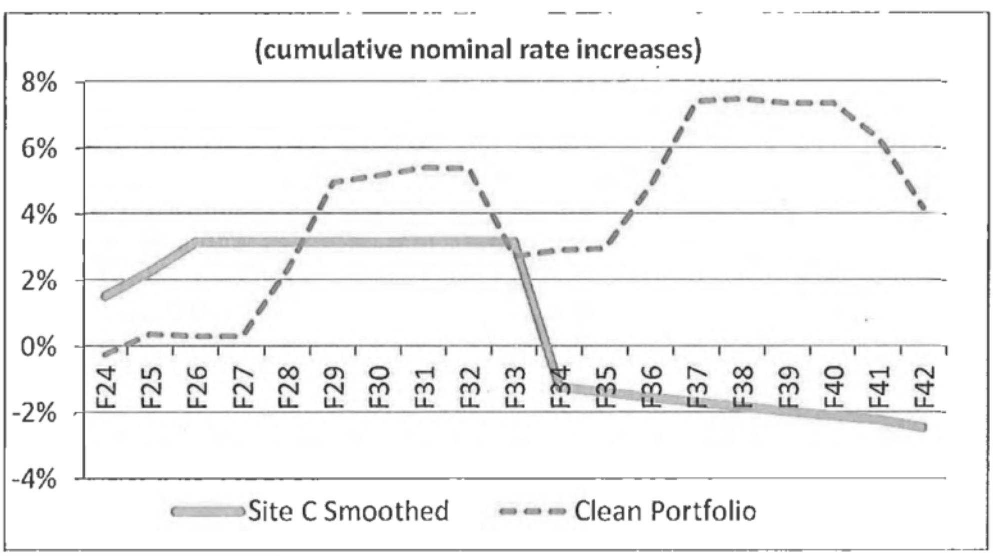
    Portfolio modelling analysis compares portfolios using the differences in the present value (PV) of the portfolio costs.
- Both analyses determined that the Site C portfolio is a lower cost option than the Clean and Clean + Thermal portfolios, as shown in Table 2.

Table 2: Financial Attributes				
Attribute	Clean Portfolio	Clean + Thermal Portfolio		Site C
		Block 1 – Rev 6 & 6 SCGTs	Block 2 – Rev 6, GMS & 4 SCGTs	
Adjusted UEC *($/MWh)*	$153	$128	$130	$91
Portfolio PV Differential (F24 ISD) ($ millions, F2013)	$630	$150		n/a

1. UEC values for the purposes of portfolio analysis are based on the blended cost 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.

- While Site C has a significant up-front capital cost, it provides large amounts of energy and dependable capacity at low operating costs and with a long asset life. As a result, Site C is less expensive than comparable Clean IPPs, even when costs of Clean IPPs are combined with thermal options (as shown in the Clean + Thermal portfolio).[7]
- BC Hydro conducted a sensitivity analysis on the financial comparison and 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. Additional information on the sensitivity analysis is provided in Appendix 1E.
- The Site C portfolio will also result in lower rates for BC Hydro's customers over the long-term. As shown in Figure 3, while the project will create an approximately 3% cumulative rate increase for the first few years, rates would then be lower for remainder of the 70-year project life. Comparative rate analysis shows a long term 10% lower rates with the Project compared to alternatives.

Figure 3: Indicative Comparative Rate Impact of Site C vs. Clean Portfolio



[7] A discussion of stand-alone thermal as an alternative (not possible under current policy), is provided in Appendix 1A.

- Ratepayers would also benefit from greater certainty in the cost of supply for Site C's operating life. The majority of Site C costs will be established once construction is complete, followed by low, predictable operating costs over Site C's 70-year planning life. Resources like wind and natural gas have a shorter operating life and would require significant replacement and rehabilitation after 20 to 30 years. In addition, projects with fuel requirements such as natural gas would be subject to volatility in market prices (see Appendix 1A) as well as potential regulatory compliance costs, such as offsets that may be required during this time horizon.

1.7.3 Environmental Attributes

- A comparison of environmental attributes is provided in Table 3. The Site C portfolio would have significantly lower greenhouse gas (GHG) and air contaminant emissions intensity than both sets of alternative portfolios.
- 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.

Table 3: Comparison of GHG and Air Emissions During Operations *(tonnes/year, thousands)*

		Clean Portfolio	Clean + Thermal Portfolio		Site C
			Rev 6 & 6 SCGTs	Rev 6, GMS & 4 SCGTs	
GHG Emissions* (*tonnes/yr, thousands*)		217	657	511	0
Local Air Emissions* (*tonnes/year, thousands*)	Sulphur Dioxide	0.1	0.1	0.1	0
	Oxides of Nitrogen	0.3	0.6	0.5	0
	Carbon Monoxide	0	1.3	0.9	0
Land Footprint (*hectares*)		2,555	1,768	2,067	5,661
Freshwater Footprint (*stream length, kilometers*)		0	0	0	123

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

- The Site C portfolio could have a larger land and freshwater footprint due to the inundation required for reservoir creation. However, land and freshwater footprints for the alternative portfolios are uncertain given that portfolios without the project are populated with "typical" projects with estimated footprints for the purposes of this analysis. The actual footprint of alternative projects would not be known until the projects were identified.
- The majority of the Site C land and freshwater footprint is a conversion of terrestrial and riverine habitat to reservoir habitat, rather than a loss of productive habitat. This change is expected to increase certain areas of aquatic productivity, including fish.

- 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.

1.7.4 Economic and Social Development Attributes

- In addition to the economic development benefits of the project's low, stable cost to ratepayers, Site C would provide economic development benefits in the northeast and the province as a whole.
- As shown in Table 4, the Site C portfolio results in higher Gross Domestic Product (GDP), tax revenues and jobs during the construction phase. During the operations phase, jobs and GDP would be lower.

Table 4: Comparison of Economic Development Attributes During Construction

	Clean Portfolio	Clean + Thermal Portfolio		Site C
		Rev 6 & 6 SCGTs	Rev 6, GMS & 4 SCGTs	
Provincial GDP (*millions*)	2,513	1,616	1,706	3,676
Prov. Revenues (*millions*)	355	231	244	517
Construction Jobs * (*total person-years*)	30,788	19,872	20,963	44,249
Operations Jobs (*jobs per year*)	998	985	958	74

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.

- There would be a number of additional, specific benefits associated with Site C, including trades training initiatives, legacy benefits for Peace region communities, recreation, 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.
- Information about specific Site C benefits is available in Appendix 11 of this briefing binder.

1.8 Conclusion and Project Justification

- BC Hydro must plan now to meet the long-term need for dependable capacity and energy in B.C. A comprehensive review of alternatives has been undertaken, showing Site C to provide the best combination of technical, financial, environmental and economic development attributes, compared to a range of available resources.
- BC Hydro concludes that Site C is the best project for ratepayers, providing low-cost energy and much-needed dependable capacity over a long life of more than 100 years. Site C would have a lower rate impact than alternatives, and would provide price certainty for decades to come.

- Site C, like any electricity-generation option, would have environmental impacts. However, years of detailed environmental studies have determined that the effects can largely be mitigated through careful project planning, comprehensive mitigation programs and ongoing monitoring during construction and operations.
- While the project has some residual adverse environmental effects, they are justified by the benefits provided to ratepayers, taxpayers, employment, economic development and communities during construction and operations.
- Site C would be a generational investment in B.C.'s electricity system, providing clean, reliable and cost-effective electricity for more than 100 years.

1.9 References

- Site C Business Case Summary (January 2013)
- Site C Environmental Impact Statement (amended July 2013)
- Site C Evidentiary Update (September 2013)
- Final Argument submitted to Joint Review Panel (February 2013)
- Final Integrated Resource Plan (November 2013)
- Undertakings in Response to Site C Joint Review Panel (December 2013 & January 2014)
- Response to Joint Review Panel Information Requests (March 2014)
- Technical Memorandums filed as part of Site C Environmental Assessment:
    - Project Need (June 2013)
    - Alternatives to the Project (June 2013)
    - Demand-Side Management (May 2013)
    - Project Costs (June 2013)
    - Hydro-Electric Storage and Dispatchable Capacity (May 2013)

1.10 Appendices

- Appendix 1A: Natural Gas Potential
- Appendix 1B: Summary of Portfolio Attributes
- Appendix 1C: Large Hydro Potential in B.C.
- Appendix 1D: Site C Impact on LNG Cost-Effectiveness
- Appendix 1E: Economic Sensitivity Analysis
- Appendix 1F: Dispatchable Capacity
- Appendix 1G: DSM Jurisdictional Review
- Appendix 1H: BC Hydro Capital Projects
- Appendix 1I: Summary of Project Benefits
- Appendix 1J: Large Hydro in Other Provinces
- Appendix 1K: Explanation of Changes to Site C Unit Energy Cost

APPENDIX 1A

NATURAL GAS POTENTIAL

Summary
To meet the long-term electricity needs of BC Hydro customers, Site C offers the best combination of financial, technical, environmental and economic development attributes of the alternatives available within the policy context of the Clean Energy Act.

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Current Policy Context

- The *Clean Energy Act* requires that 93% of the electricity generated in B.C. come from clean or renewable resources. As a fossil fuel-based resource, the total amount of gas-fired generation that can be built is limited to 7%, and would not be enough to replace Site C.
- There are two types of natural gas-fired generation facilities:
  - *Simple-Cycle Gas Turbines* (SCGTs) use a gas combustion turbine to propel a turbine similar to a jet engine connected to an electrical generator. SCGTs are quick to start up and provide peak capacity but are less efficient at generating energy than CCGTs.
  - *Combined Cycle Gas Turbines* (CCGTs) use a combination of a gas combustion turbine and a steam turbine. The waste heat from the gas turbine is used to power the steam turbine, resulting in higher efficiency than SCGTs. Consequently, these plants are typically used for base load energy, rather than peak capacity.

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APPENDIX 1B

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APPENDIX 1B

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APPENDIX 1C

LARGE HYDRO POTENTIAL IN B.C.

Summary

Several large hydroelectric projects have been considered by BC Hydro over the past number of decades. An updated review of these projects in 2008 concluded that Site C remains the most attractive hydroelectric option.

- In addition to the Site C project, BC Hydro has historically looked at a number of other large hydroelectric projects in B.C. throughout the 1950s, 60s, 70s, and 80s.
- In 2008, as part of the Long-Term Acquisition Plan (LTAP), BC Hydro updated information about nine of the most attractive potential large hydro projects. These projects are shown on a map in Figure 1.
- Subsequently, Sections 10 and 11, and Schedule 2, of the *Clean Energy Act* prohibited the development of the large hydroelectric projects reviewed in 2008, with the exception of Site C.
- The projects reviewed for the purposes of the 2008 LTAP consisted of:
  - **Elaho**, a 200 MW, 945 GWh/yr earthfill dam and powerhouse to be sited on the Elaho River, six kilometres upstream of the Squamish River.
  - **McGregor Lower Canyon**, a 360 MW, 1,673 GWh/yr earthfill dam and powerhouse to be located at Lower Canyon on the McGregor River approximately 30 kilometres upstream of the confluence with the Fraser River. This project would create a 23,000 hectare reservoir that would potentially encroach on the boundaries of the Arctic Pacific Lakes Provincial Park.
  - **Murphy Creek**, a 275 MW, 1,794 GWh/yr earthfill dam and five unit powerhouse to be situated on the Columbia River three kilometres upstream of the City of Trail. Households adjacent to the proposed reservoir and sections of railway, highway, and municipal infrastructure would need to be relocated. In addition, there would likely be impacts to White Sturgeon, a species listed under the *Species at Risk Act*.
  - **Border**, a 275 MW, 1,418GWh/yr low-head concrete dam and powerhouse to develop the remaining head on the Columbia River in B.C. It would be located on the Columbia River near its confluence with the Pend d'Oreille River. Some residences in the City of Trail could be displaced, and municipal infrastructure, roads and parts of Highway 22A would be flooded.
  - **Homathko River**, an 895 MW, 4,558 GWh/yr development consisting of four dams and three powerhouses in an undeveloped river basin in the Coastal Mountains. It would include: a dam and 290 MW powerhouse on Mosley Creek; a dam and 420 MW power

plant on Waddington Canyon on the Homathko River; a storage dam on Tatlayoko Lake; and a dam and 185 MW powerhouse on the Homathko River at Nude Canyon. The facilities would be located within the boundaries of the Homathko River-Tatlayoko Protected Area Provincial Park.

- **Liard River**, a 4,318 MW, 24,825 GWh/yr development consisting of 3 dams and powerhouses on the Liard River in northern B.C. Approximately 160 kilometres of the Alaska Highway and five communities would have to be relocated to accommodate the project. In addition, the Fort Nelson Regional Land Management Plan designates areas of the Liard watershed as protected.
- **Iskut River**, a 980 MW, 4,293 GWh/yr project comprising two dams and powerhouses at More Creek and Iskut Canyon in northwest B.C. BC Hydro no longer has the rights to the land on which these projects would be located. Alta Gas has three electricity purchase agreements with BC Hydro for energy from its run-of-river hydroelectric development on the Iskut River near Iskut Canyon. Once constructed, these projects are expected to provide about 280 MW and 1,200 GWh/year to BC Hydro customers.
- **Low Site E**, a 675 MW, 3,210 GWh/yr project comprising a combined dam and powerhouse on the Peace River, three kilometres upstream of the B.C.-Alberta border. Low Site E was studied in conjunction with earlier studies of Site C in the mid-1970s which concluded that Site C would be considerably more economic than Low Site E. In 1985 the Province removed the flood reserves for Site E. Low Site E would flood agricultural land and would require the relocation of a number of riverside residents.
- **High Site E**, an 1,800 MW, 8,500 GWh/yr, 330-foot high dam and powerhouse. Studies carried out in the mid-1970s concluded that power development using both Low Site E and Site C would have less environmental impact than High Site E, including flooding of about 60 per cent less area. High Site E would affect the main highway and railway bridge crossings of the Peace River at Taylor. Major ground movements could occur between Site C and Site E with a High Site E dam.

- There were additional projects that BC Hydro had historically considered that were prohibited by legislation prior to 2008, and were therefore not updated in the 2008 review:
  - The Cutoff Mountain site on the Skeena River and several sites on the Stikine River. Both of these potential large hydro developments were legislatively barred pursuant to Section 4 of the B.C. *Fish Protection Act*, which designates the Skeena and Stikine Rivers as "protected rivers" and prohibits the construction of bank-to-bank dams.
  - McGregor River Diversion project would entail diverting most of the McGregor River flows across the divide between the Pacific and Arctic watersheds into the Peace River basin. Section 6 of the *Water Protection Act* prohibits the construction of "large scale projects" capable of transferring a peak instantaneous flow of 10 cubic metres of water a second between major watersheds.
- The review in 2008 consisted of updates to cost and schedule information for each project.

Costs

- Based on the 2008 analysis, Site C was the least expensive option (on a unit energy cost basis) of similarly sized individual projects (such as Low Site C, Iskut, McGregor Lower Canyon, and Low Beavercrow project on the Liard River). There are no current comparable cost estimates available for these other large hydro options as they are now excluded by provincial legislation.
- Generally, larger developments such as the full development of multiple dams on the Liard or Homathko basins could have a unit energy cost comparable or lower to Site C. However, these developments would include significant inundation of unregulated rivers (with accompanying environmental effects).

Schedule and Permitting

- Each of the large hydro projects would have a nameplate capacity greater than 50 MW, and would thereby trigger similar regulatory requirements to Site C. This includes the requirement to obtain an Environmental Assessment Certificate pursuant to B.C. *Environmental Assessment Act*, and would also trigger the Federal *Fisheries Act* and *Canadian Environmental Assessment Act*.
- All of the large hydro projects considered are expected to have a longer development and construction period than Site C.

Land Requirements

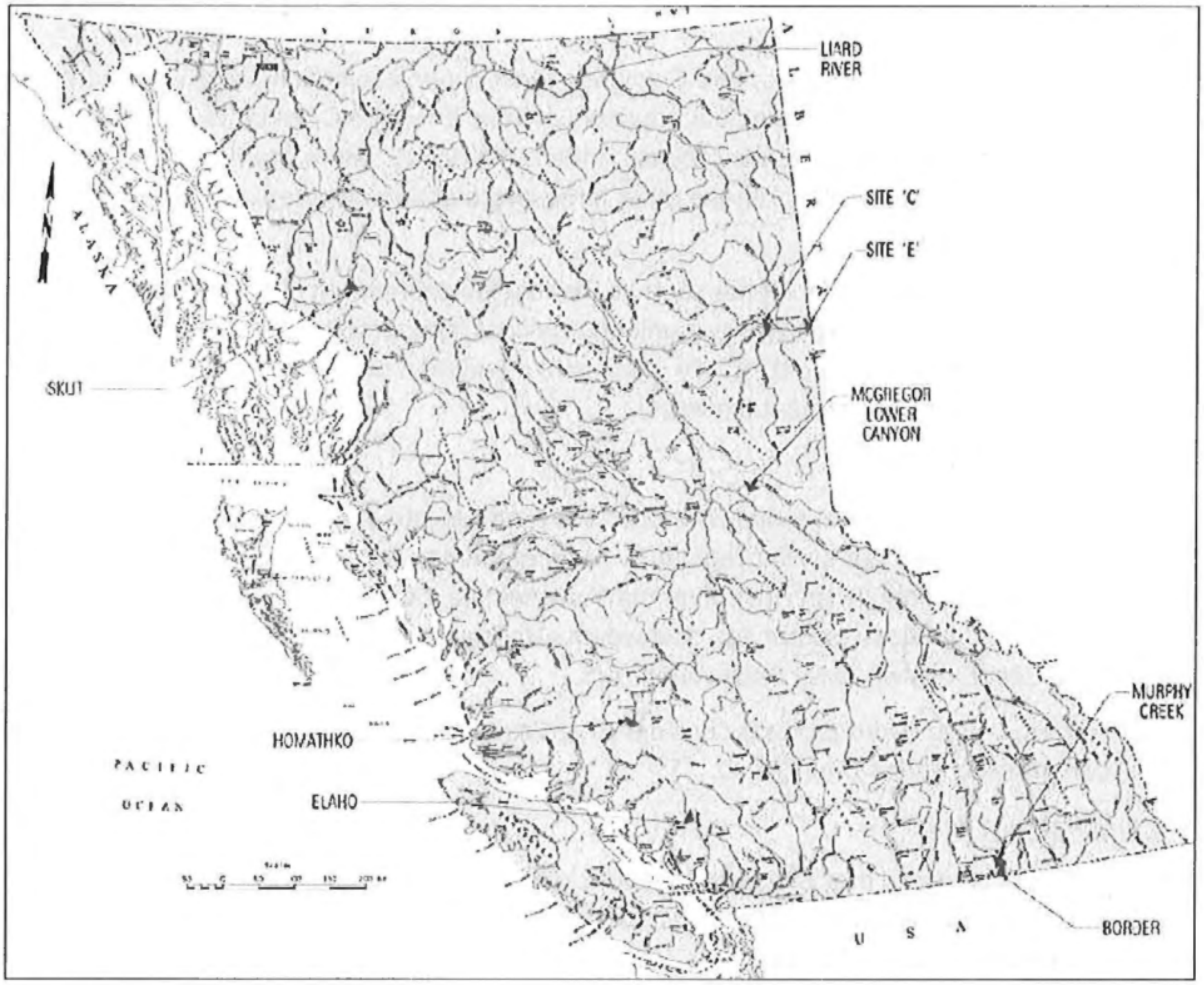
- It should be noted that Site C is the only large hydroelectric project that BC Hydro currently holds a flood reserve for. BC Hydro and the Crown own 92% of the land that would be permanently affected by Site C.
- BC Hydro does not own any of the land that would be required for the other projects.

Conclusion

- The conclusion in the 2008 LTAP report was that Site C remained the most attractive large hydro project available for BC Hydro to develop. BC Hydro came to this conclusion prior to the prohibitions stated in the *Clean Energy Act*.

s.12,s.13

Figure 1: Location of Other Large Hydro Projects



References

- 2008 Long-Term Acquisition Plan, Appendix F8: Potential Large Hydro Project Report

APPENDIX 1D

s.12,s.13

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ECONOMIC SENSITIVITY ANALYSIS

Summary

A number of key conditions underlie BC Hydro's conclusion that Site C is the preferred option to help meet long-term electricity needs. To test this conclusion, BC Hydro conducted sensitivity analysis that compares the cost-effectiveness of Site C to alternative resources in a range of potential future scenarios, including large and small electricity gaps, high and low spot market prices, lower costs of capital for alternatives, higher Site C capital costs, and a combination of these variables. The analysis confirms that Site C remains the preferred option for ratepayers under a range of conditions.

Issue

- This note provides a summary of the sensitivity analysis undertaken in the Integrated Resource Plan (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 case, 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 the Project; 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 Environmental Impact Statement (EIS) and the IRP.

Large and Small Gap Conditions

- The gap between supply and demand affects the economic analysis of alternatives because it determines the level of short-term surplus created 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 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 percent 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 Demand-Side Management (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/yr compared to the target level DSM savings of 7,800 GWh/yr);
  - 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.
- Table 1 summarizes the Present Value (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 1: Sensitivity of Project Benefit to Electricity Gap Condition
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	In-Service Date	Large-Gap (~10% likelihood)	Base (Mid-Gap) Case (~80% likelihood)	Small-Gap (~10% likelihood)
Clean Portfolio	F2024	See Note 1	630	(1,040)
	F2026		880	(705)
Clean + Thermal Portfolio	F2024	2,260	150	(1,280)
	F2026	See Note 1	390	(907)

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

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. In the case of High LNG Load (6,600 GWh), the need for new energy resources advances from F2027 to F2021. In the case of Low LNG Load (800 GWh), the need for new energy resources advances from F2027 to F2024.

- There is no change to the *timing* of required capacity resources under any LNG scenarios, but the *amount* of capacity required increases by 100 MW (Low LNG) to 800 MW (High LNG) in the F2020 to F2022 timeframe.

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 that IPP developers. In its decision on the 2006 IEP/LTAP the BCUC found that IPPs' cost of debt is higher than BC Hydro's.
- The base assumption for the Weighted Average Cost of Capital (WACC) is 5% for BC Hydro and 7% for clean or renewable IPPs. A sensitivity test was performed assuming 6% WACC for IPPs, effectively reducing the cost of capital differential between BC Hydro and IPPs from 2% to 1%.
- 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 2.

Table 2: Sensitivity of Project Benefit to Cost of Capital Differential of 1%
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	Cost of Capital	In-Service Date	Difference in PV Cost
Clean Portfolio	6%	F2024	420
		F2026	672
Clean + Thermal Portfolio	6%	F2024	20
		F2026	233

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 3 market scenarios are the most likely with a combined likelihood of 95%.[1]

- The PV benefits of Site C over the Clean and Clean + Thermal portfolios are shown in Table 3. 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 $43/MWh in F2024) and smaller in the low market scenario (with a projected spot market price of about $24/MWh in F2024).
- In the Market Scenario 2 low market sensitivity case[2] (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.

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 recent BCUC proceedings for 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 $75/kW-year to about $110/kW-year, 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 we assigned a value to capacity, it would increase the value of the short-term surplus.

Table 3: Sensitivity of Project Benefit to Market Prices
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	In-Service Date	Scenario 3: High Market Prices *(15% likelihood)*	Scenario 1: (Base Case) Mid- Market Prices *(60% likelihood)*	Scenario 2: Low Market Prices *(20% likelihood)*
Clean Portfolio	F2024	830	630	450
	F2026	1,028	880	755
Clean + Thermal Portfolio	F2024	470	150	(90)
	F2026	656	390	217

[1] 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.

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

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, based on the definitions of the Association for the Advancement of Cost Engineering. It includes an appropriate level of contingency to reflect uncertainty in future conditions. 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%, 15% and 30% while the cost of all other alternatives remains constant. It is important to note that the scenario with a 30% 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 Joint Review Panel 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% increase in cost. This 30% 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 4 below summarizes the portfolio PV results of the capital cost sensitivity analysis. With the plus 10% 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 4: Sensitivity of Project Benefit to Capital Cost Increase
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	Clean Portfolios		Clean + Thermal Portfolios	
	F2024	F2026	F2024	F2026
Base Case	630	880	150	390
Site C 10% Capital Cost Increase All other alternatives held constant	360	650	(120)	170
Site C 15% Capital Cost Increase All other alternatives held constant	250	560	(230)	70
Site C 30% Capital Cost Increase All other alternatives held constant	(60)	270	(580)	(220)
Site C 30% Capital Cost Increase **Alternative Resources 30% Increase**	600	950	(100)	300

- 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.

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% capital cost overrun.[3]
  - 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% 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 5 summarizes the results of the compound sensitivity analysis.

Table 5: Compound Sensitivities for LRB Gap, Market Price and Site C Capital Cost
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	Clean Portfolios		Clean + Thermal Portfolios	
	F2024	F2026	F2024	F2026
Base Case Mid Gap, Mid-Market Price (Scenario 1) Reference Site C Capital Cost	630	880	150	390
Compound Low Scenario Small Gap, Low Market Price (Scenario 2) 10% Site C Capital Cost Increase)	Note 1	Note 1	(2,000)	(1,600)
Compound High Scenario Large Gap, High Market Price (Scenario 3) 10% Site C Capital Cost Decrease	Note 1	Note 1	2,610	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.

[3] The Compound Low contains the small electricity gap scenario, which is a low likelihood scenario that would effectively see negligible 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).

- As shown in Table 5, 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).

Conclusion

- 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 6 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 6: Sensitivity Analysis Summary
Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C), $F2013 millions

	Clean Portfolios		Clean + Thermal Portfolios	
	F2024	F2026	F2024	F2026
Base Case Mid Gap, Mid-Market Price (Scenario 1), WACC Differential = 2%, Wind Integration Cost = $10/MWh	630	880	150	390
Large Gap	Note 1	Note 1	2,260	Note 1
Small Gap	(1,040)	(705)	(1,280)	(907)
High Market Price (Scenario 3)	830	1,028	470	656
Low Market Price (Scenario 2)	450	755	(90)	217
Exchange Rate (0.62 USD/CAD)	950	Note 1	570	Note 1
Exchange Rate (1.085 USD/CAD)	570	Note 1	90	Note 1
Site C Capital Cost +10% alternatives held constant	360	650	(120)	170
Site C Capital Cost +15%, alternatives held constant	250	560	(230)	70
Site C Capital Cost +30%, alternatives held constant	(-60)	270	(580)	(220)
Site C and Alternatives Capital Cost +30%	600	950	(100)	300
WACC Differential of 1%	420	672	20	233
Wind Integration Cost ($15/MWh)	720	Note 1	222	Note 1
Wind Integration Cost ($5/MWh)	530	Note 1	92	Note 1
Compound Low Scenario (Small Gap, Low Market Price, 10% Site C Capital Cost Increase)	Note 1	Note 1	(2,000)	(1,600)
Compound High Scenario (Large Gap, High Market Price, 10% Site C Capital Cost Decrease)	Note 1	Note 1	2,610	Note 1

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

References

- Integrated Resource Plan (November 2013): Chapter 6: Resource Planning Analysis

HYDROELECTRIC STORAGE AND DISPATCHABLE CAPACITY

Summary

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.

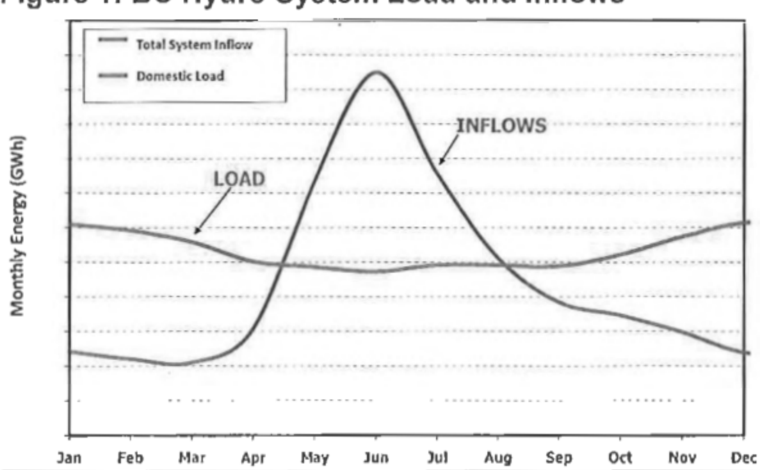
Issue

- BC Hydro must meet the electricity requirements of its residential, commercial and industrial customers. Meeting this demand requires BC Hydro to have sufficient generation resources in its system to meet both energy and capacity needs.
    - *Energy* is the amount of electricity produced or used over a period of time.
    - *Dependable Capacity* is the maximum amount of electricity that BC Hydro can supply to meet peak customer demand in the province at a point in time.
- Hydroelectric storage is a key source of dependable capacity, because water can be stored when it is not needed, and later used to create electricity when demand is high.

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% 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

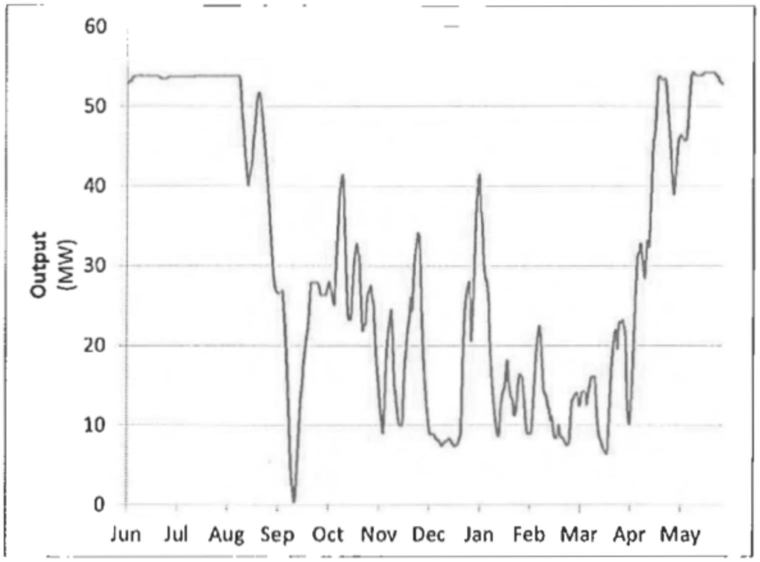
- An additional benefit of hydro-electric storage is the ability to integrate energy projects with low dependable capacity such as wind and run-of-river hydro.
- Many clean or renewable energy resources – such as wind or run-of-river hydro – are intermittent, as their generation varies with natural factors. 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: Typical 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 2 and 3 show sample 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)

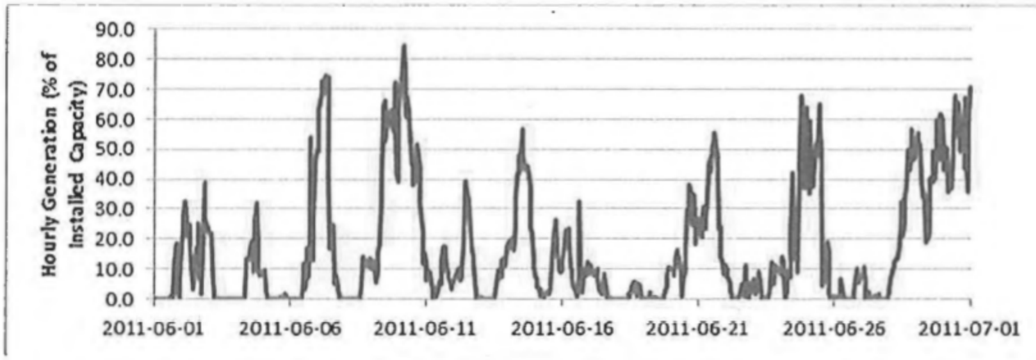
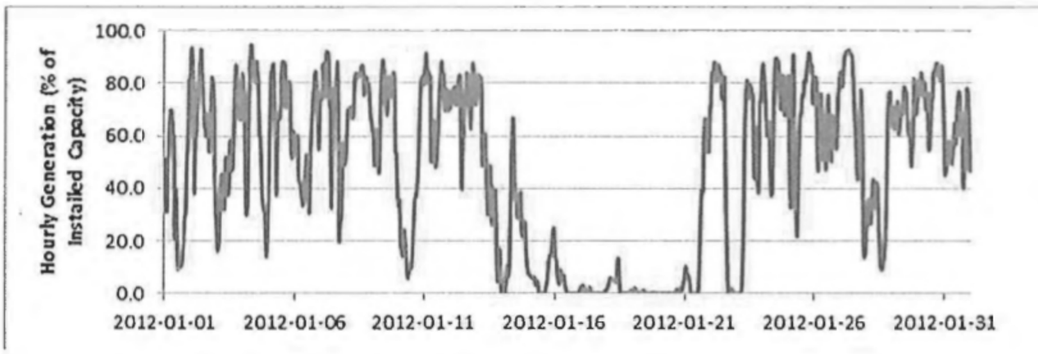


Figure 4: Sample Wind Generation during Wintertime (January 2012)



- 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.

References

- Technical Memorandum: Hydro-Electric Storage and Dispatchable Capacity (May 2013)

DEMAND-SIDE MANAGEMENT JURISDICTIONAL REVIEW

Summary

Demand-side management (DSM) is BC Hydro's first and largest option to meet electricity demand, and BC Hydro plans to meet 78% of its load growth through these conservation and efficiency initiatives. However, even accounting for these measures, new electricity generation resources are required to meet long-term demand.

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.

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. Massachusetts[1] 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.

[1] As of 1 April 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.

- 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.

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 of 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

Table 1: Average Annual Energy Savings from DSM Programs as Per Cent of Retail Sales *(2005 to 2009)*	
Organization *(625kWh Average Residential Rate)*	**Average** *(%)*
16. Hydro Quebec	0.50
17. New Jersey Clean Energy	0.40
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.

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.

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 1H

BC HYDRO CAPITAL PROJECTS

Summary

BC Hydro is investing in its heritage assets to ensure system reliability, and undertaking new projects to meet future electricity demand in B.C. Even with these projects, there is a need for new electricity generation to meet long-term energy and capacity needs. The following is a summary of BC Hydro's planned and contemplated projects over $50 million.

PLANNED PROJECTS OVER $50 MILLION[1]

BC Hydro has planned for the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

- **Seymour Arm Series Capacitor Station (SASC)**
  In-service: 2013
  Total cost: $48 million
  LTD cost: $44 million

  Construct a 500 kV series capacitor station adjacent to the existing transmission lines 5L71 and 5L72, which run between Mica Generating Station and Nicola Substation near Merritt. The capacitor station will increase the transmission capacity of the lines and allow Mica Generating Station to securely deliver its full station output with the new generating units 5 and 6 in place.

- **Mica SF6 GAS Insulated Switchgear (GIS) Replacement Project**
  Targeted completion: 2014
  Total cost: $199 million
  LTD cost: $155 million

  Replace the switchgear system at Mica Generating Station to ensure the reliability of this key generating station and reduce SF6 (a greenhouse gas) leakage. The switchgear system, energized at 500 kV, conducts energy from the Mica underground powerhouse to the surface, where it transitions to transmission lines.

- **Northwest Transmission Line Project (NTL)**
  Targeted completion: 2014
  Total cost: $746 million
  LTD Cost: $563 million

[1] The capital expenditure amounts do not include dismantling or asset retirement costs. Life to date (LTD) costs are as of December 31, 2013.

Construct an approximately 340 km, 287 kV transmission Line between Skeena Substation near Terrace and a new substation to be built near Bob Quinn Lake to ensure a reliable supply of clean power to potential industrial developments in the area; provide a secure interconnection point for clean generation projects; and potentially help certain northwest communities access their power from the electricity grid rather than diesel generators.

**Total cost represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer prior to the in-service date. An additional $90 million will be received from a customer as annual payments over 20 years after the in-service date. The LTD cost has not been netted for $107 million in contributions to date from the Federal Government.*

- **Merritt area Transmission Project (MAT)**
  Targeted completion: 2014
  Total cost: $65 million
  LTD cost: $14 million

  Construct a new 138-kilovolt transmission line between Merritt and Highland substations, expand Merritt Substation and add new equipment at Highland Substation to meet the increased demand for power in the Merritt area.

- **Vancouver City Central Transmission (VCCT)**
  Targeted completion: 2014
  Total cost: $201 million
  LTD cost: $160 million

  Build an enclosed 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation to the existing transmission network to serve growing loads in the Mt . Pleasant/False Creek area and maintain a reliable supply of electricity to other areas of Vancouver.

- **Dawson Creek / Chetwynd Area Transmission (DCAT)**
  Targeted completion: 2015
  Total cost: $296 million
  LTD cost: $59 million

  The project will expand the Peace Region 230 kV transmission system to the Dawson Creek-Chetwynd area to supply the high area load growth. The solution will include the construction of new 230kv lines between Dawson Creek and Bear Mountain (BMT), and from BMT to a new station called Sundance, located approximately 19 km east of Chetwynd. Change from F2014 Service Plan reflects increase in cost estimates for labour and materials and additional project consultation requested by the BCUC. The total cost estimate is within the range provided in the Certificate of Public Convenience and Necessity (CPCN) application update in March 2012.

- **Iskut Extension Project**
  Targeted Completion: 2015
  Total cost: $180 million
  LTD cost: $17 million

  Construction of a 92 km, 287 kV transmission extension, plus a 16 km distribution line from Bob Quinn substation. The transmission line would terminate at a new substation at Tatoga Lake and the 16 km, 25 kV distribution line continuing to Iskut.

  **The total cost represents the gross cost of the project and has not been netted to reflect contributions of $40 million from a customer.*

- **G.M. Shrum Units 1 to 5 Turbine Replacement**
  Targeted completion: 2015
  Total cost: $272 million
  LTD cost: $105 million

  Replace the Units 1 to 5 turbines to reduce the risk of runner failure, decrease maintenance costs and improve operating efficiency.

- **Long Beach Area Reinforcement (LBAR)**
  Targeted completion: 2015
  Total cost: $56 million
  LTD cost: $5 million

  Expansion of Long Beach (LBH) and Great Central Lake substations with two new transformers at each and capacitor banks at LBH to support the load growth and provide voltage support in the area.

- **Surrey Area Substation Project**
  Targeted completion: 2015
  Total cost: $94 million
  LTD cost: $13 million

  Construct a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The supply to the station will be from circuit 2L75 and will allow for increased station capacity of 400 MVA.

- **Interior to Lower Mainland Project (ILM)**
  Targeted completion: 2015
  Total cost: $725 million
  LTD cost: $391 million

  Construct a new 500 kV transmission line, approximately 247 km in length, between Nicola Substation near Merritt and Meridian Substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the

Lower Mainland. The project is facing scheduling pressures due to contractor delays. The project will be in-service in 2015.

- **Smart Metering & Infrastructure Program**[2]
  Targeted completion: 2015
  Total cost: $930 million
  LTD cost: $655 million

  The Smart Metering and Infrastructure Program (SMI) includes the installation of 1.9 million smart meters in Homes and businesses across the province, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems.

- **Hugh Keenleyside Spillway Gate Reliability Upgrade**
  Targeted completion: 2015
  Total cost: $123 million
  LTD cost: $64 million

  Upgrade the spillway gates at the Hugh Keenleyside Dam to increase public and employee safety by ensuring the gates meet flood discharge reliability requirements.

- **Upper Columbia Capacity Additions at Mica – Units 5&6**
  Targeted completion: 2015
  Total cost: $714 million
  LTD cost: $383 million

  Install two additional 500 MW generating units into existing unit bays at Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines.

- **Big Bend Substation**
  Targeted completion: 2016
  Total cost: $56 million
  LTD cost: $12 million

  The South Burnaby, Big Bend area requires a new, 100 MVA, 69/12 kV Substation to meet local residential and commercial load growth.

- **Ruskin Dam Safety and Powerhouse Upgrade**
  Targeted completion: 2017
  Total cost: $748 million
  LTD cost: $205 million

  This upgrade project will improve dam stability and replace the powerhouse equipment, which is in poor and unsatisfactory condition. It is expected to take six years to complete

2 Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral

and includes: reinforcement of the right embankment; seismic upgrade of the dam and water intakes; powerhouse upgrades; and, relocation of the switchyard. Once completed, the upgraded facility will be reliable and safe and will produce enough electricity to serve more than 33,000 homes. BC Hydro received a CPCN from the BCUC for the project in March 2012.

- **John Hart Generating Station Replacement**
  Targeted completion: 2019
  Total cost: $1.093 billion
  LTD cost: $95 million

  Replace the existing six-unit 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation and to mitigate earthquake risk and environmental risk to fish and fish habitat. In February 2013, BC Hydro received a CPCN from the BCUC for the project. The total cost is within the range outlined in the F2014 Service Plan.

CONTEMPLATED PROJECTS OVER $50 MILLION

BC Hydro is contemplating the following projects over $50 million commencing during Fiscal 2015–Fiscal 2017, listed in alphabetical order. These projects are in the initial project phases; scope, final cost and benefit assessment, and completion dates are still to be determined. These projects have not yet been approved by the Board of Directors.

- **Bridge River 2 Units 5 and 6 Rehabilitation**
  Restore Bridge River 2 Units 5 and 6 (commissioned over 60 years ago) to "as new condition." This would address known major component deficiencies and enable the units to run at full capacity (currently de-rated from 70 MW to 60 MW).

- **Cheakamus Unit 1 and Unit 2 Generator Replacement**
  Replace the two generators at Cheakamus Generating Station (commissioned over 50 years ago) to address the poor condition and known deficiencies. Replacing the generators will increase the capacity of each unit from 70 MW to 90 MW.

- **Downtown Vancouver Redevelopment Program**
  Upgrade and expand the transmission and distribution network serving downtown Vancouver over the next 20 to 30 years to improve reliability and seismic resiliency. The project includes the addition of a new transmission cable coming into the downtown core, the construction of new substations, and the refurbishment and/ or replacement of the existing substations. The project also includes converting the existing distribution system from a 12 kV dual radial system to a 25 kV open-loop system to feed off the new transmission system.

- **G.M. Shrum G1-G10 Control System Upgrade**
  The condition of the legacy controls for GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of spare parts availability and decreasing reliability. The controls are well beyond their expected life, cause operating problems and increase the risk of damage to major equipment.

- **Horne Payne Substation Upgrade**
  Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers; three 25kV 50MVA indoor gas-insulated (GIS) feeder sections; and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution topology. Conversion to 25kV will also eliminate the existing issue of high fault current on the distribution bus at Horne Payne and reduce distribution losses.

- **John Hart Dam Seismic Upgrade**
  Upgrade the John Hart Dam to reliably withstand moderate to severe earthquake loadings and meet normal operations criteria post-earthquake.

- **Ladore Upgrade Dam Spillway Gates**
  Reduce the risk of failure of the spillway gates and hoist structure due to a seismic event. Improve post-seismic operability in order to prevent the subsequent uncontrolled release of water into the downstream John Hart Reservoir and maintain reservoir control in the system.

- **Metro North Transmission Study**
  A new 230 kilovolt (kV) transmission line(s) is proposed between Coquitlam and Vancouver to address load growth in the Metro Vancouver area and to strengthen the reliability of the network.

- **Peace Region Electric Supply**
  Increase transmission capacity to the South Peace area by providing a second 230 kV supply to Dawson Creek in response to the significant load growth in the area, mainly from the gas production industry.

- **Prince George Terrace Capacity Upgrade (PTGC)**
  The Prince George to Terrace Capacitors project will increase the capacity of the 500kV circuit supplying the north coast areas. This will increase the transfer capacity by up to approximately 60 per cent through the addition of reactive compensation. This additional capacity is required to provide capacity for industrial loads expected to interconnect to in the Northwest. The timing of the PGTC project is linked to the interconnection of Shell's LNG Canada Liquefied Natural Gas plant that is scheduled for early 2019.

- **Revelstoke Unit 6 Installation**
  Supply and install an approximately 500 MW unit in the existing empty unit 6 bay at Revelstoke Generating Station to add capacity to the BC Hydro system. Revelstoke Unit 6 is identified as a contingency resource in BC Hydro's 2013 Integrated Resource Plan, a 20-

year plan accepted by the Provincial Government that describes how BC Hydro proposes to meet future growth in demand for electricity.

- **Terrace – Kitimat Transmission Project**
  Replace the existing transmission lines serving the Kitimat area that has reached the end of its serviceable life. This project would replace the 60km transmission line -2L99- that runs between Skeena and Minette substations and the 3km transmission line -2L103- that runs between Minette and Kitimat substations with new 287kV lines on a new right of way. Both of these lines have been de-rated due to defects and deficiencies, and cannot supply current and forecast load demands.
- **W.A.C. Bennett Dam Rip-Rap Upgrade**
  The W.A.C. Bennett Dam rip-rap has degraded since its completion in 1968. The project will rebuild the upstream slope to ensure there is adequate protection and shielding to the embankment dam from the wind-generated waves.

References:

- BC Hydro Service Plan: 2014/2015 to 2016/2017

APPENDIX 1I

SUMMARY OF PROJECT BENEFITS AND JUSTIFIABILITY

Summary

Site C would benefit the BC Hydro system as a new source of firm energy and dependable capacity. In addition, the construction of Site C would create thousands of jobs, boost GDP and provide additional revenues to all levels of government. Environmental benefits include low GHGs, the optimization of existing resources, and the integration of intermittent renewables. Among the benefits to local communities from the Site C project are a regional legacy benefits agreement, infrastructure improvements, recreation and tourism opportunities, affordable housing and skills training. Finally, agreements would be expected to provide economic and social development benefits for First Nations' communities.

Issue

- The Site C project would provide system benefits related to firm energy and dependable capacity. In addition, the construction and operation of Site C would also provide benefits related to economic development, the environment, communities, and Aboriginal groups.

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.

Cost-Effective Electricity Supply

- Site C would generate electricity at a levelized cost (UEC) of $82/MWh at the point of interconnection.
- Site C will result in lower rates for BC Hydro's customers over the long-term. While the project will create an approximately 3% 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 in response to varying levels of energy supplied by intermittent resources (e.g., wind). Refer to Appendix 1F for details.

Economic Development

- 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 direct and indirect 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.

Economic Activity

- Building Site C would contribute $3.2 billion to provincial GDP from the purchase of goods and services during construction, including approximately $130 million to regional GDP.

Government Revenues

- During construction, Site C would result in a total of $40 million in tax revenues to local governments and, once in operation, $2 million in revenue from grants-in-lieu and school taxes.
- Activities during construction would result in approximately $176 million in provincial revenues, and approximately $270 million for the federal government.
- The Province would receive annual water rentals amounting to over $35 million per year.
- A regional legacy benefits agreement would provide $2.4 million annually to the Peace River Regional District (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.

Environmental Benefits

Optimizing Existing Resources

- The Site C reservoir would be comparatively smaller than BC Hydro's other major hydroelectric projects because it would rely on the existing Williston Reservoir for water storage. This would enable 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 1F for details.

Community Benefits

Regional Legacy Benefits

- A regional legacy benefits agreement between BC Hydro and the PRRD would provide $2.4 million 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 will be improved after BC Hydro's use by being graded for future industrial land use.

Recreation and Tourism Opportunities

- BC Hydro is proposing funding for tourism improvements, including building a viewing site for construction of the dam, enhancing the W.A.C. Bennett Dam Visitor Centre, and funding regional and local museums.
- Water-based recreation is expected to increase in the reservoir compared to today as a result of greater potential boat access. Three new boat launches would replace the two existing today.
- 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 three-year funding agreement of $105,000 with Northern Opportunities for its pre-apprenticeship program.

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Conclusion - Justifiability

- BC Hydro has concluded that while the Site C project has the potential to result in some significant residual effects, they are justified by:
  - The public interest is served by delivering long-term, reliable electricity to meet growing demand.
  - Employment, economic development, ratepayer, taxpayer and community benefits would result.
  - The ability of the project to meet electricity needs with lower greenhouse gas emissions than other resources.
  - The limited footprint of the project — as the third project on one river system — given its generation capability using water already stored upstream in the Williston Reservoir.
  - The honourable process of engagement with First Nations and the potential for accommodation of their interests.

References

- Site C Business Case Summary, Chapter 5: Project Benefits, January 2013.
- Site C Environmental Impact Statement Executive Summary (Amended July 19, 2013).

APPENDIX 1J

LARGE HYDRO IN OTHER PROVINCES

Summary

In areas where it is geographically possible, many Canadian jurisdictions are building or proposing large hydro, including Manitoba, Quebec, Newfoundland and Labrador, and Ontario. Like Site C, many of these projects would be built downstream of existing storage reservoirs, which allows these projects to gain significant efficiencies. Most recent hydroelectric projects in other provinces have not been required to obtain approvals similar to a Certificate of Public Convenience and Necessity (CPCN) from their respective provincial utility regulators.

Overview

- There was a significant build of large hydro-electric projects across Canada in the 1960s and 1970s. This period finished with several contemplated projects left "on the shelf". Every province with significant potential hydro-electric resources is currently pursuing these options.
  - Most provinces have now brought previous projects off the shelf, with the exception of Québec, where projects continued to be built with no real pause.
  - Most projects currently being pursued represent additional projects on rivers where there are already existing facilities.
- All projects are at least partially justified by the economic benefits that result from the export of power outside of the province – often to the United States.
  - B.C. is an exception to this. All recent projects in B.C. have been justified based on domestic needs.
- Most large hydro projects currently being discussed in Canada are being developed by Crown corporations or their subsidiaries.
  - Historically, the only common exception to Crown Corporations building large hydro projects has been the development of large hydro by forestry or mining companies to serve a large industrial load.
  - The only new projects in B.C. have been developed by Columbia Power Corp (also a Crown corporation) in recent years.
- Most recent hydro-electric projects in other provinces have not been required to obtain approvals similar to a CPCN from their respective provincial utility regulators. The Keeyask project in Manitoba is the only known exception.

Important Note on Comparing Hydro Projects

- While this document presents several projects with similar attributes to Site C, these projects cannot be directly compared to each other. Each project has unique features such as the project geology and foundation conditions, the river characteristics, and the social context in which they were constructed. Differences in these features can create significant differences in project schedules, costs and generated energy.

Manitoba Hydro: Nelson River Development

- The Nelson River development consists of three projects on the Nelson River in Manitoba, where Manitoba Hydro has five existing hydroelectric projects.
- The projects are downstream of a major storage reservoir and regulation at Lake Winnipeg. There is also an existing diversion of the Churchill River into the Nelson River to augment flows.
- The Wuskwatim project is a 200 MW / 1,550 GWh/yr dam and powerhouse. Construction began in 2006 and was completed in 2012.
- The Keeyask project is a 695 MW / 4,400 GWh/yr dam and powerhouse. Construction is planned to begin in summer 2014 and complete in 2019.
    - Manitoba Hydro awarded a contract for the general civil works on the project in March 2014.
    - The Keeyask project is currently undergoing a Need and Alternatives review by the Manitoba Public Utilities Board.
- The Conawapa project is a 1,485 MW / 7,000 GWh/yr dam and powerhouse. This project remains in the planning stage, with no current planned construction start date.
- All the Nelson River development projects have been primarily justified on the economic benefits of power export to the United States, with long-term domestic load growth as a secondary rationale.

Hydro-Quebec: Romaine Hydro Development

- The Romaine Hydro development is a set of four dams on the Romaine River in Quebec. This River was previously undeveloped by Hydro Quebec.
- The four dams and powerhouses are planned for construction as a group. They consist of:
    - Romaine 1, providing 260 MW and 1,400 GWh/yr
    - Romaine 2, providing 610 MW and 3,300 GWh/yr
    - Romaine 3, providing 380 MW and 2,000 GWh/yr
    - Romaine 4, providing 250 MW and 1,300 GWh/yr
- Construction of the development began in 2009. The first units are expected to enter service in 2014, with the final units in service in late 2020.

- The Romaine development has been primarily justified on the economic benefits of power export to the United States, with long-term domestic industrial load growth as a secondary rationale.
- Romaine was further justified based on the economic benefits for the Côte-Nord region.

Nalcor: Lower Churchill Development

- The Lower Churchill development is a set of two projects on the Churchill River in Labrador.
- There is storage and regulation provided upstream of the Lower Churchill projects at the existing 5,500 MW Upper Churchill project.
- The projects are also associated with the Labrador-Island link transmission project (which would bring electricity from Labrador to Newfoundland) and the Maritime Link transmission project (which would bring electricity from Newfoundland to Nova Scotia allowing access to export markets).
- Muskrat Falls is an 824 MW / 4,900 GWh/yr dam and powerhouse. Construction began in 2013 and is anticipated to be completed in 2017.
- Gull Island would be a 2,250 MW dam and powerhouse. This project remains in the planning stage, with no current planned construction start date.
- Justification of Muskrat Falls is based on a combination of forecast increases in domestic demand in Newfoundland and Nova Scotia, as well as potential economic benefits of electricity export to markets in Ontario and the United States.

Ontario Power Generation: Lower Mattagami

- The Lower Mattagami development is a combination of a new greenfield powerhouse and dam improvements as well as unit additions at three existing powerhouses. All facilities are located on the Mattagami River in Ontario.
- The Lower Mattagami development consists of the following projects:
    - Replacement of the current 52MW Smoky Falls powerhouse with a 267MW powerhouse, along with upgrades to the associated dam.
    - Addition of a 62 MW generating unit at the Long Lake powerhouse.
    - Addition of a 78 MW generating unit at the Harmon powerhouse.
    - Addition of a 78 MW generating unit at the Kipling powerhouse.
- All four projects are being constructed as a single development. Construction began in 2010.
- The additional unit at Long Lake was completed in early 2014. The balance of the Lower Mattagami project is expected to be complete in 2015.
- Justification of the Lower Mattagami project is generally based on forecast domestic demand growth in Ontario.

APPENDIX 1K

EXPLANATION OF CHANGES TO UNIT ENERGY COSTS

Summary

This document provides a summary of the Unit Energy Cost (UEC) values commonly used by BC Hydro in the Site C analysis. BC Hydro generally uses the Unit Energy Cost (UEC) as an indication of the life-cycle cost of a resource option or portfolio. There are several ways to view the UEC which either include or exclude specific costs. In addition, there have been changes to the input data to UEC values over time, which change the UEC values.

For the Site C **Business Case** and **EIS** (January 2013), two UECs were used for Site C.

- A project UEC of **$87-95/MWh**, which was:
  - At the point of interconnection (POI) to the BC Hydro transmission system
  - Based on a discount rate of 5.5 - 6%
  - Included sunk costs (expenditures already made on the project)
- A portfolio UEC of **$110/MWh** was also used for comparison purposes, which:
  - Was based on the $95/MWh, but adjusted beyond POI to include transmission-related costs, wind integration costs, soft costs and costs of capacity back-up
  - It excluded sunk costs to reflect future spending decisions compared to alternatives

For the **IRP** and Site C **Evidentiary Update** to the regulatory agencies (Fall 2014), these UECs were updated to reflect a 1% reduction in discount rates due to a reduction in Ministry of Finance forecast long-term borrowing cost. The resulting UECs for Site C were:

- A project UEC at point of interconnection of **$83/MWh**
- A portfolio UEC of **$94/MWh** adjusted to the Lower Mainland (note that a 1% reduction was also applied to IPP portfolios).

The **current** UEC for Site C has been further updated, resulting in the following UECs:

- A project UEC of **$82/MWh**, reflecting the elimination of Tier 3 water rental rates ($1/MWh reduction) and including sunk costs.
- Excluding sunk costs, the project UEC is **$78/MWh**, which represents a more relevant comparison for economic analysis.
- A portfolio UEC of **$91/MWh,** which reflects the revised water rentals, and includes a shaping adjustment ($2/MWh reduction) to allow comparability with CCGT gas blocks.