BC hydro

Integrated Resource Plan

Chapter 6

Resource Planning Analysis

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6.1 Introduction

This chapter presents the resource planning analysis conducted utilizing the analytical framework described in Chapter 4 to inform the long-term planning actions that should be pursued to fill the Load-Resource Balance (**LRB**) gaps. As described in section 2.4.2, the LRBs and need for new resources have been analyzed at a number of stages. Chapter 4 addresses the manner in which BC Hydro prudently manages near-term costs while maintaining an adequate, cost-effective longer term supply. The LRB gap analyzed in the portfolios in this chapter reflects this cost management approach, and are summarized in Table 4-18 and Table 4-19. The LRBs are shown in Figure 4-3 and Figure 4-4.

The analysis presented in this chapter is grouped into three categories:

- LRB Mid Gap Before Expected LNG - As described in Chapter 4, the mid gap is based on BC Hydro's 2012 mid-load Forecast. The Recommended Actions to fill the mid gap prior to LNG lead to the Base Resource Plan (**BRP**) as described in section 9.2.
- LRB Mid Gap with Expected LNG - Based on discussions with the B.C. Government and LNG proponents, the Expected LNG load is 3,000 GWh/year (360 MW) as early as F2020. To inform its plans, BC Hydro has considered both the Expected LNG load as well as a range in LNG load of 800 GWh/year to 6,600 GWh/year, as described in Chapter 2. Future demand from the LNG industry warrants specific analysis given that the size of these loads, potentially concentrated within a transmission constrained region, can have a significant impact on resource plans. Recommended Actions to enable BC Hydro to supply these large loads when LNG proponents enter into energy supply contracts with BC Hydro and make their final investment decisions are presented in section 9.3.

- Contingency Conditions – Contingency Resource Plans (**CRPs**) address how BC Hydro would supply larger LRB gaps due to significant planning uncertainties such as load growth being greater than expected (e.g., higher load forecast) and/or planned resources under delivering, and in particular lower levels of energy and capacity savings from Demand Side Management (**DSM**) given the extent of planned reliance on DSM. Recommended Actions to prepare for contingency conditions are presented in section 9.4. BC Hydro also considers planning uncertainties that would result in smaller LRB gaps, and flexibility and off-ramps that should be maintained for each resource.

The remainder of this chapter is structured as follows. Sections 6.2 to 6.4 discuss the generation resource mix to serve load growth prior to Expected LNG as follows:

- **Natural Gas-Fired Generation (section 6.2):** Natural gas-fired generation is a cost-effective resource option that emits greenhouse gases (**GHGs**) and is limited by the *Clean Energy Act* (***CEA)*** 93 per cent clean or renewable energy objective. This section explores how the 7 per cent non-clean headroom (which excludes LNG loads per the British Columbia's Energy Objectives Regulation described in section 1.2.4) can best be used to meet forecasted needs.
- **DSM (section 6.3):** Given the *CEA* 93 per cent clean or renewable target and the DSM target to reduce BC Hydro's expected increase in demand for electricity by F2021 by at least 66 per cent, DSM, Site C and clean or renewable independent power producer (**IPP**) acquisitions are the major options available to meet long-term resource requirements. In this section, the relative cost-effectiveness of DSM is compared to clean or renewable IPPs and Site C, and the implications of having Site C in the plan are considered. The analysis shows that the current long-term DSM target as well as Site C are cost-effective.

- **Site C (section 6.4):** The continued role of Site C as a cost-effective resource is tested, including sensitivities to major input assumptions.

Section 6.5 considers the additional resource requirements to serve Expected LNG and the North Coast region:

- **LNG and the North Coast (section 6.5):** This section begins with a discussion of the additional resource requirements to serve potential LNG load in BC Hydro's service area. The majority of the LNG load is expected to be concentrated in the North Coast region. The supply strategies and transmission planning considerations specific to this region are also addressed in this section.

Sections 6.6 to 6.9 discuss other potential new loads, transmission resources and contingency conditions:

- **Other Incremental Load Scenarios:** Potential large new loads could emerge in the Fort Nelson/Horn River Basin (**HRB**) region (section 6.6) and from general electrification (section 6.7). In sections 6.6 and 6.7, the planning environment and load potential from each of these areas are discussed along with supply strategies and resource requirements.
- **Transmission (section 6.8):** This section identifies the transmission requirements to support resource requirements under mid gap, LNG scenarios and contingency conditions.
- **Capacity and Contingency Analysis (section 6.9):** This section begins by identifying the remaining need for capacity for the mid gap LRB. Next, a range of planning uncertainties is described and contingency conditions considered. The strategy to address these uncertainties leading to the development of the two CRPs is then discussed.

Section 6.10 provides the differential rate impact analysis between portfolios:

- **Differential Rate Impact Analysis (section 6.10):** This section reviews the British Columbia Utilities Commission (**BCUC**) decision concerning BC Hydro's 2006 Integrated Electricity Plan (**IEP**)/Long-Term Acquisition Plan (**LTAP**) where the BCUC found that an economic test comprising Present Value (**PV**) and levelized cost of energy (Unit Energy Cost (**UEC**)) is the primary test with rate impact being a secondary test. Consistent with Certificate of Public Convenience and Necessity (**CPCN**) application treatment, BC Hydro sets out the relative rate impacts for portfolios with different levels of DSM (i.e., DSM Option 2/DSM Target, DSM Option 1, DSM Option 3), Site C and alternative resources (including IPP resources).

The analytical results shown in this chapter include key findings based on technical, financial, environmental and economic development attributes. Detailed results from the IRP analysis, including portfolio composition, results and PV cost differences, as well as environmental and economic development attributes, are provided in Appendix 6A.

6.2 Natural Gas-Fired Generation

6.2.1 Introduction

The use of natural gas-fired generation is governed by the following energy objectives as set out by the *CEA* and subsequent regulations:

- To generate at least 93 per cent of the electricity in B.C., from clean or renewable resources, other than electricity to serve demand from facilities that liquefy natural gas for export by ship
- To reduce B.C. GHG emissions pursuant to the legislated *Greenhouse Gas Reduction Targets Act* (***GGRTA***), GHG reduction targets are discussed in section 5.4.2.2
- To encourage energy efficiency and clean or renewable electricity through:

- Development of innovative technology in B.C.
- Use of waste heat, biomass or biogas
- Use and development of clean or renewable resources in First Nations and rural communities

Natural gas-fired generation is not a clean or renewable resource as defined by the *CEA*. Section 1 of the *CEA* provides that "clean or renewable resource means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource". The Clean or Renewable Resource Regulation[1] provides that biogenic waste, waste heat and waste hydrogen are clean or renewable resources. To meet the *CEA* objectives, BC Hydro evaluated natural gas-fired generation within the remaining headroom of 7 per cent for non-clean resources[2] for serving non-LNG loads, and has only contemplated exceeding this headroom in the Fort Nelson/Horn River Basin load scenarios where there are limited supply options.

As discussed in section 5.4.2.2, Policy Action No. 18 of the 2007 BC Energy Plan provides that new natural gas-fired generation is to have net zero GHG emissions. Natural gas-fired generation is also subject to the carbon tax; however, the B.C. Government has indicated in the Climate Action Plan that it is will not charge the carbon tax when natural gas-fired generation is required to acquire and retire offsets.[3] Natural gas-fired generation may be exempted from the carbon tax under section 84 of the *Carbon Tax Act*, which states that the Lieutenant Governor in Council (**LGIC**) may make regulations providing for exemptions from the payment of

[1] B.C. Reg. 291/2010.

[2] Although all non-clean or renewable resource options can use the 7 per cent non-clean headroom, the discussion here focuses on natural gas-fired resource options. Gas is the default non-clean generation option for most utilities because it is a proven technologically, is available in significant amounts, is the most efficient, and has the least GHG emissions and criteria air contaminants compared to other non-clean options. Other non-clean options such as diesel will continue to be generation options where no other options are available/feasible (e.g., in some Non-Integrated Areas (**NIAs**)) but their usage/energy volume will be negligible.

[3] The Climate Action Plan states at page 15: "To avoid unfairness and what might effectively be double taxation, the carbon tax and complimentary measures such as the 'cap and trade' system will be integrated as these other measures are designed and implemented".

tax, or for refunds of all or part of the tax paid, with respect to a fuel or combustible that is the source for GHG emissions that are subject to the requirements of *Environmental Management Act* (***EMA***). Such a regulation has not been issued to date by the LGIC. GHG offset cost assumptions are set out in section 5.4.3.3 and are used in the portfolio modelling analysis in this chapter. BC Hydro assumes that natural gas-fired generation would incur the maximum of either the B.C. carbon tax of $30 per tonne of carbon dioxide equivalent (CO_2e) emissions or the GHG prices shown for B.C. in Table 5-3.

Natural gas-fired generation can be a significant source of dependable capacity and firm energy. The dispatchable and dependable nature of gas-fired generation can enable the integration of intermittent and non-dispatchable renewable resources such as wind and run-of-river hydro.[4] The cost of natural gas-fired generation is competitive given the current price of natural gas and the longer-term outlook for natural gas prices and GHG offset costs in most of the market scenarios analyzed in the IRP. Unlike many other resource options, gas may have flexibility to be sited in locations that yield greater value (e.g., near load centres or in transmission constrained areas). However, there are significant constraints for locations near load centres, in particular air emission permitting requirements and related social licensing issues. Its relatively short construction lead time, once permitting is secured, also makes it a good candidate as a contingency resource.

Natural gas-fired generation also has drawbacks. The cost of gas-fired generation is uncertain due to the historically volatile cost of natural gas and GHG offsets markets. There are also permitting and development risks in B.C.

The key IRP questions for this resource option are:

- What is the optimal use of the 7 per cent non-clean headroom?

[4] For example, natural gas-fired generation can be turned off when generation from non-dispatchable run-of-river hydro is high when load is light such as during the freshet. Gas turbines can also provide firming for wind integration.

- ▶ Where should the allowable natural gas-fired generation be sited?
- ▶ When should the 7 per cent non-clean headroom be used?

- What natural gas-fired generation is needed to serve LNG loads? (This question is addressed in section 6.5.)

6.2.2 Applying the 93 per cent *CEA* Objective to Resource Planning

BC Hydro interprets the *CEA* 93 per cent clean or renewable objective, which states "to *generate* electricity at least 93 per cent of the electricity" [emphasis added], as applying to the actual output of generation facilities as opposed to the planned reliance on the facilities.[5] BC Hydro must plan its system such that the objective can be met when operating its facilities. BC Hydro reviewed several possible interpretations of the 93 per cent clean or renewable objective. Their application to the IRP and their consistency with the *CEA* are as follows:

(a) **Meet the objective on average:** Enabling BC Hydro's generation to be at least 93 per cent clean or renewable while meeting all of BC Hydro's load obligations (net of DSM and net of LNG loads) from B.C. resources and be able to do so under average water conditions (i.e., being able to meet the objective by averaging the clean generation percentage over a period of time, but not necessarily meeting the 93 per cent clean or renewable objective in every year). In this approach, BC Hydro would develop resource plans where energy contribution of Heritage hydroelectric facilities under average water conditions combined with the firm energy contribution from clean or renewable IPP resources would be at least 93 per cent of load requirements.

(b) **Meet the objective every year:** Taking a similar approach to (a) but for critical water conditions (i.e., being able to meet the objective in every year even under low water conditions when more reliance on thermal resources may be required).

[5] Specifically, it is the ratio between clean electricity and the total electricity generated within the Province.

(c) **Meet the objective (on average or every year) by relying on import of market energy:** Enabling BC Hydro's actual generation output to be at least 93 per cent clean or renewable without consideration of whether all of BC Hydro's load obligations can be met from B.C. resources. In practice, this would allow BC Hydro to rely on significant amounts of natural gas-fired generation, with the intention to displace natural gas-fired generation with market energy import to meet load during operations. The minimized generation from natural gas-fired facilities in B.C. to meet load allows BC Hydro's generation to be at least 93 per cent clean or renewable even though a significant portion of the BC Hydro system load would be met by market imports.

BC Hydro ruled out approach (c) since this would defeat the intent of the *CEA* which sets out the electricity self-sufficiency requirement and the 93 per cent clean or renewable objective. As discussed in the 2008 LTAP, BC Hydro has been using approach (b), in accordance with the 90 per cent clean generation policy objective in the 2007 BC Energy Plan. By comparison, approach (a) would provide greater flexibility to use natural gas-fired generation. BC Hydro proposes to use approach (a) since it is consistent with the recent move to average water planning and it is a cost-effective action that meets the intent of the *CEA* energy objectives. In planning for average water conditions, BC Hydro is able to manage its resources and avoid being oversupplied in a low-priced market.

6.2.3 Resource Planning with Gas-Fired Generation

BC Hydro relies on natural gas-fired generation for both dependable capacity and firm energy. The energy reliance is based upon how frequently these facilities are expected to operate, with the minimum being 18 per cent over the full course of a year (i.e., 18 per cent capacity factor). The 18 per cent capacity factor assumption was established in the 2008 LTAP. It reflects that natural gas-fired generation, even if built purely for capacity purposes, would need to be capable of running at least at 18 per cent of the time to provide dependable capacity.

Whether to increase the minimum energy reliance depends upon the expected utilization of a particular plant, with the output of all gas-fired units remaining within the available 7 per cent non-clean headroom. As described in section 3.4.1.9, there are two main categories of gas-fired turbines:

- Combined Cycle Gas Turbines (**CCGTs**) are typically built where there is a need for both dependable capacity and an expectation of high utilization (typically used for base load energy type plants). CCGTs are a highly efficient technology, have a relatively high capital cost and are economic when operated at a high capacity factor. In the analysis, a firm energy contribution based on a 90 per cent capacity factor and a minimum must run requirement based on 70 per cent capacity factor has been used for CCGTs.
- Simple Cycle Gas Turbines (**SCGTs**) are typically built for dependable capacity (for use as peakers),[6] have lower capital cost than CCGTs, faster ramp rates and allow frequent starts/stops, but are significantly less efficient than CCGTs. SCGTs are readily dispatched off in favour of surplus energy or low cost market purchases. While SCGTs are typically not operated for many hours, the combination of SCGTs/surplus system energy/low cost markets have economic benefits while ensuring adequate dependable capacity is available to meet peak load requirements and adequate firm energy is available during very dry water years and tight market conditions. In the analysis, an 18 per cent capacity factor has been used in determining the firm energy contribution and the minimum must run requirement for SCGTs.

[6] Peakers (or peaking plants) are power generation plants that typically only run at times of peak demand.

6.2.4 Non-Clean Headroom with the 93 per cent Clean Objective

As stated in section 6.2.2, BC Hydro plans such that the average water output of Heritage hydroelectric facilities combined with the firm capability of clean or renewable IPP resources would serve at least 93 per cent of the load net of DSM. BC Hydro has four existing natural gas-fired generation facilities in its system[7] that take up part of the 7 per cent headroom available. They are:

- Fort Nelson Generating Station (**FNG**) – BC Hydro facility
- Prince Rupert Generating Station – BC Hydro facility
- Island Generation Plant – Electricity Purchase Agreement (**EPA**)
- McMahon Cogeneration Plant – EPA

These existing facilities provide approximately 3,500 GWh/year of non-clean firm energy contribution. BC Hydro plans to continue relying on the energy from these facilities within the planning horizon. (BC Hydro's plan to exercise an option to extend the McMahon Cogeneration Plant EPA is discussed in section 9.2.4.2). The remaining non-clean energy headroom available for new natural gas-fired generation during the planning horizon based on the mid gap (Option 2/DSM Target, no LNG load) scenario, as shown in Figure 6-1. Figure 6-2 shows the corresponding capacity, assuming capacity factors of 18 per cent and 90 per cent that are typical of SCGTs and CCGTs, respectively.

[7] As described in section 2.3.2.1 and as required by subsections 3(5) and 6(2)9b) of the *CEA*, BC Hydro does not plan on any energy contribution from Burrard and hence Burrard does not have any impact on the 93 per cent clean or renewable objective from a planning perspective. BC Hydro also operates several diesel generators in NIAs. Their energy contributions are relatively minor and have no material impact on the 93 per cent clean or renewable objective.

Figure 6-1 Available Headroom for Non-Clean Firm Energy

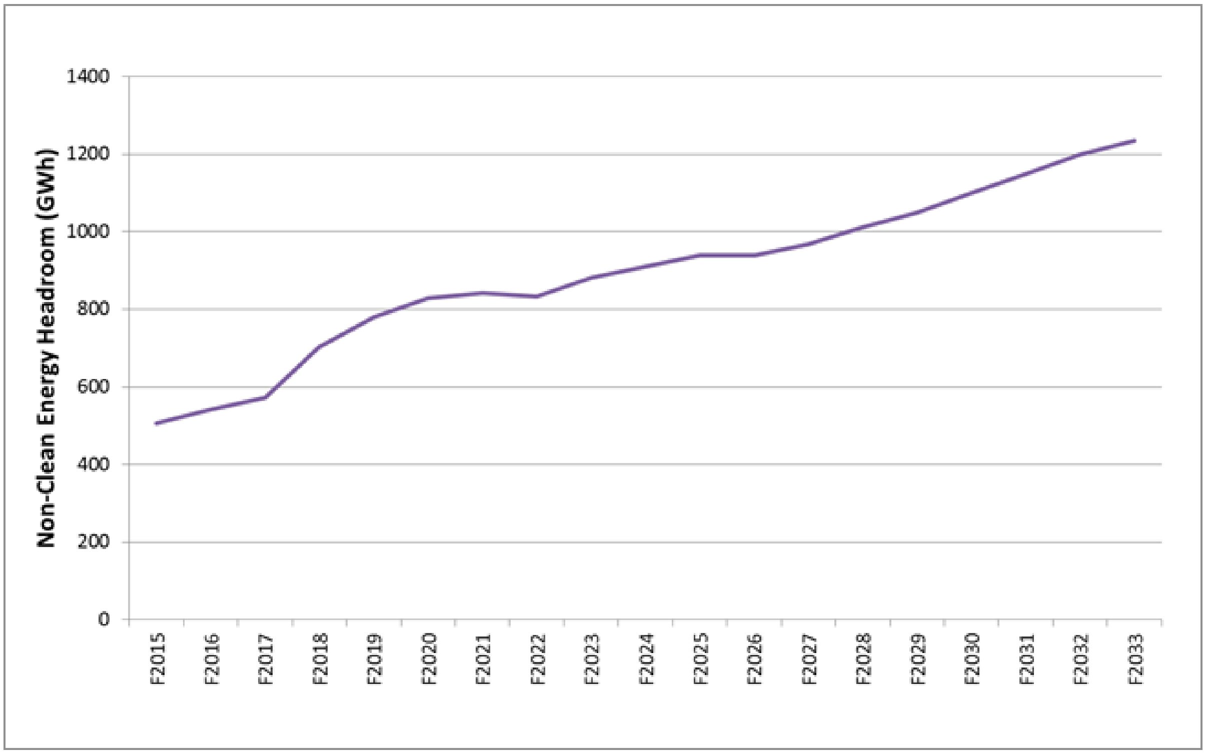
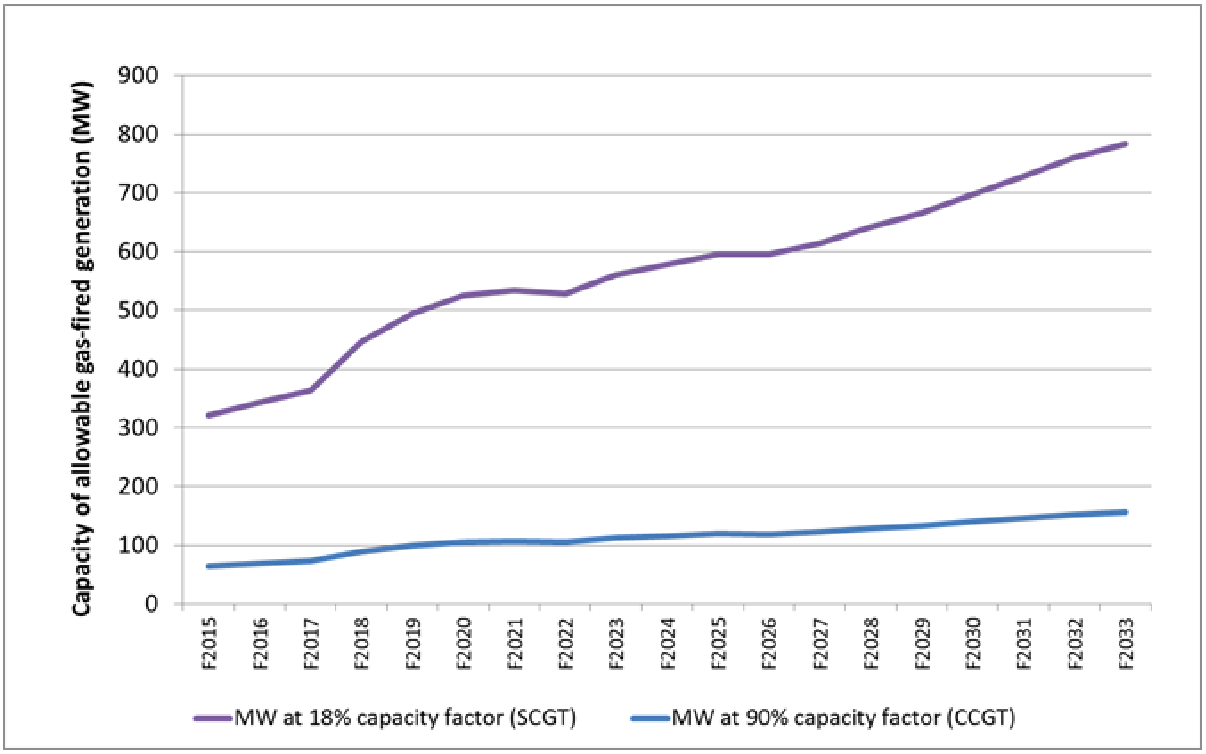


Figure 6-2 Available Headroom for Non-Clean Capacity (based on 18 per cent and 90 per cent capacity factor)



6.2.5 Permitting Natural Gas-Fired Generation

New natural gas-fired generation greater than or equal to 50 MW requires an Environmental Assessment Certificate (**EAC**) pursuant to *B.C. Environment Assessment Act* (***BCEAA***) and an air emission permit under the *Environmental Management Act* (***EMA***). Securing an EAC and/or air emission permit for natural gas-fired generation could be a lengthy process and have an uncertain outcome in some regions of the Province. For example, Metro Vancouver has responsibility for issuing air emission permits for Lower Mainland facilities,[8] and has taken the public position that it would not welcome natural gas-fired generation within the Lower

[8] Per section 31 of *EMA*.

Fraser Valley airshed.[9] In addition, the Province, in its news release[10] concerning Direction No. 2[11] to the BCUC, cited concerns with Burrard Thermal Generating Station's (**Burrard**) air emissions in the Lower Fraser Valley airshed as a reason for the directive.

6.2.6 Cost of Gas-Fired Generation Compared to Clean Resources

Gas-fired generation is generally lower in cost compared to clean or renewable resources, in particular under the most likely market scenario (i.e., Market Scenario 1). Table 6-1 compares the costs of natural gas-fired generation under the range of market scenarios described in Chapter 5 to the cost of Site C and the weighted average cost of IPP clean or renewable energy equivalent to the energy available from Site C(i.e., 5,100 GWh/year).

[9] For example, D.Bell, Metro Vancouver, letter to Washington State Energy Site Evaluation Council, "Re: Draft Notice of Construction/Prevention of Significant Deterioration Permit and Supplementary Draft Fact Sheet for Sumas Energy 2 Generating Facility", September 28, 2000.

[10] B.C. Ministry of Energy, Mines and Petroleum Resources, "News Release: Province Advances Commitment to Clean, Renewable Energy", October 28, 2009, page 1.

[11] B.C. Reg. 254/2009, repealed by B.C. Reg. 318/2010 and replaced by sections 3(5), 6(2)(d) and 13 of *CEA* and the Burrard Thermal Electricity Regulation, B.C. Reg. 319/2010.

Table 6-1 Adjusted UECs[12] of CCGT for Various Market Scenarios, Site C and IPPs

Market Scenarios	Market Scenario Likelihood (%)	50 MW CCGT ($/MWh)	250 MW CCGT ($/MWh)	500 MW CCGT ($/MWh)	Site C ($/MWh)	IPPs ($/MWh)
Scenario 1[13]	60	85.96	60.51	56.90	83	125
Scenario 2[14]	20	71.33	45.99	42.33		
Scenario 3[15]	15	101.86	76.29	72.76		
Scenario 4[16]	4	94.64	68.87	65.29		
Scenario 5[17]	1	138.97	111.02	107.49		

Table 6-1 provides the detailed breakdown of the adjusted UECs for Market Scenario 1, as shown in Table 6-1.

12 All cost values presented in this chapter (UECs, Unit Capacity Costs (**UCCs**), capital costs) are expressed in $2013 unless otherwise stated. The nominal cost of a generation or transmission asset will be higher when it comes into service and will depend on the length of time from now up to the in-service date of the asset as well as the escalation in costs that occur in the interim. For example, an asset that costs $1 million in 2013 would cost $1.22 million in 10 years' time due to the impact of general inflation alone.

13 Medium Electricity, Medium regional GHG (Carbon tax for B.C.), Medium Gas.

14 Low Electricity, Low regional GHG (Carbon tax for B.C.), Low Gas.

15 High Electricity, High regional GHG (Carbon tax for B.C.), High Gas.

16 Medium Electricity, Medium regional/national GHG, Medium Gas.

17 High Electricity, High regional/national GHG, High Gas.

Table 6-2 Breakdown of UECs for CCGTs, Site C and IPPs

$/MWh (F2013$)	50 MW CCGT (Note 1)	250 MW CCGT (Note 1)	500 MW CCGT (Note 1)	Site C (excluding sunk cost)	Site C (including sunk cost)	IPP (Note 2)
UEC at POI	92	62	58	79	83	96
GHG cost Adjustments (for emissions during operational phase)	12	11	11	0	0	0
Locational Adjustments (CIFT)	3	3	3	6	6	2
Locational Adjustments (Line losses)	4	3	2	9	9	10
Locational Adjustments (Network Upgrade)	0	0	0	0	0	6
Soft Cost Adder	5	3	3	0 (Note 3)	0 (Note 3)	5
Firm Energy Adjusters	-21	-13	-12	0 (Note 5)	0 (Note 5)	-2
Wind Integration Cost	0	0	0	0	0	9
Capacity Credits	-8	-8	-8	-11	-11	0
Adjusted UEC without Capacity Credit	94 (Note 4)	69	65	94	98	125 (Note 4)
Adjusted UEC with Capacity Credit	86 (Note 4)	61	57	83	88 (Note 4)	125 (Note 4)

Note 1: Costs quoted for CCGTs reflect gas and GHG levelized prices for the most likely market price scenario (i.e. Scenario 1 of $4.6/GJ and $30/tonne respectively for gas and GHG) as well as a 90% capacity factor. Given the *CEA* 93% clean or renewable objective, the non-clean headroom would allow up to ~900 GWh of new gas generation by F2024 (i.e., equivalent to ~120 MW of CCGT).

Note 2: Cost quoted is based on a bundle of resources making up 5,100 GWh block of energy (equivalent to energy from Site C), see section 6.4 for more details.

Note 3: Soft cost already included in cost estimate (i.e., UEC at Point of Interconnection (**POI**).

Note 4: Numbers do not match up exactly due to rounding.

Note 5: The Adjusted UEC for Site C would decrease by about $2/MWh to reflect the seasonal, daily and hourly shaping capability of the project but a conservative zero adjustment is assumed here.

The UECs for CCGTs and IPP resources include a 5 per cent soft cost adder that reflects that there would likely be mitigation, First Nations consultation, public engagement and regulatory review costs. Such costs are already included in the Site C UEC. The details of the IPP resources making up the 5,100 GWh/year block are provided in section 6.4.2. A 90 per cent capacity factor is assumed for the

CCGTs. The table also illustrates that the comparative energy benefit is maximized when the energy is generated by more efficient larger sized gas-fired units.

Natural gas-fired generation is also a low cost source of capacity. A comparison of the Unit Capacity Costs (**UCCs**) for a SCGT and other supply side capacity options is provided in Table 6-3. Note that the UCCs in Table 6-3 represent only fixed costs at the POI and do not include fuel and variable operating costs, nor a credit for firm energy contribution to the system. The numbers for pumped storage costs also do not reflect the fact that pumped storage facilities are net users of energy. The cost of firm energy resources required to offset the system energy loss is estimated to be around $84 million[18] per year based on a 1,000 MW pumped storage facility operating at an 18 per cent capacity factor. The UCC of a pumped storage facility would increase by $84/kW-year if this cost is taken into account. A detailed discussion of capacity options is provided in section 3.4.2.

Table 6-3 Cost of Capacity Options

Capacity Resource	UCC ($kW-year)
GMS Units 1-5 Capacity Increase	35
Revelstoke Unit 6	50
SCGT	>=84[19]
Pumped Storage – Mica Pumped Storage - Other	100 >=118[20]

6.2.6.1 Environmental and Economic Development Considerations

The use of natural gas-fired resources to displace clean or renewable energy and/or capacity resources, or transmission will have an effect on the environmental and economic development attributes being tracked for a portfolio. A comparison of the

[18] Based on an IPP firm energy cost of $125/MWh as shown in Table 6-1.

[19] The UCC shown is for a SCGT located at Kelly Lake which is in close proximity to transmission and a major gas pipeline.

[20] The UCC shown is for the lowest cost Pumped Storage site identified in studies on potential pumped storage sites in B.C. A Pumped Storage project located at another site would have a higher UCC.

attributes between a portfolio that uses the 7 per cent non-clean headroom and a portfolio using only clean or renewable resources is shown in section 6.4.6.

6.2.7 Optimal Use of the 7 per cent Non-Clean Headroom

The optimal use and siting of natural gas-fired generation can provide significant economic benefits over and above the cost benefits identified in the previous section. The key questions are “where” and “when” natural gas-fired capacity should be used to yield the most benefits.

6.2.7.1 Using Gas as a Transmission Alternative

Siting natural gas-fired generation in remote areas (e.g., areas currently connected to the system with a long radial transmission line or areas currently non-integrated) could avoid or defer costly transmission or enable BC Hydro to serve load that it may otherwise not be able to serve because of long lead times for transmission. In addition, natural gas-fired generation located in a load centre can provide additional benefits in the form of increased transmission maintenance flexibility and increased transmission stability as described in section 6.5.3.

Factors that need to be considered in evaluating the use of natural gas-fired generation at a particular location include the number and size of units required and whether the units must be base loaded. In general, it is economic to build larger, more efficient units as illustrated by the data in Table 6-1 . It is also preferable to build natural gas-fired generation at locations where peaking units can be built since they take up significantly smaller gas headroom. This enables greater amounts of dependable natural gas-fired generation capacity at different locations in BC Hydro’s service area providing transmission benefits at each location.

BC Hydro identified a few locations where siting natural gas-fired generation could yield benefits related to avoidance or deferral of transmission, aid transmission stability and facilitate maintenance. Table 6-4 provides a list of these locations, the potential transmission options to these regions and their capital costs. The capital costs are indicative of the order of magnitude of the investments required. Each of these regions and their associated planning issues are discussed in more detail below.

Table 6-4 Potential Required Transmission to Load Centres and Associated Costs[21]

Region	Potential Transmission Requirement	$ Billion
North Coast	500 kV transmission line from Williston to Skeena substations	1.1
Fort Nelson/HRB	500 kV North East Transmission Line	1.1
Lower Mainland/ Vancouver Island	500 kV Interior to Lower Mainland Transmission line (5L46)	0.7
South Peace Region	South Peace area transmission reinforcements	0.3

North Coast

As discussed in section 6.5, the electricity demand in the North Coast region may increase significantly, primarily due to the development of several LNG facilities and new mines. The region is currently interconnected to the rest of the BC Hydro system by a radial 500 kV transmission line (consisting of three cascading 500 kV circuits). This line, even after non-wire upgrades, may not be capable of transferring sufficient electricity from the integrated system to serve all of the potential new loads. A new 500 kV transmission line requires eight to ten years of development time and would have high capital costs and permitting risks. In comparison to building a new transmission line and adding more generating capacity units at other locations on the integrated system, natural gas-fired generation in the form of SCGTs in the North Coast could be a cost-effective option to meet the potential increased regional loads in a timely manner (SCGTs would have about a five-year lead time which could be reduced somewhat through advanced planning and expedited approvals; see section 9.3.1). The SCGTs operating as peaking units can

[21] Costs shown in the table are capital costs including Interest During Construction (**IDC**) in $2013 with -50 per cent to +100 per cent accuracy.

enhance the transmission reliability of the existing radial transmission system and provide dependable capacity to supply expected load increases in the region.

Although the use of natural gas-fired generation to serve LNG load is not limited by the 7 per cent non-clean headroom, the unique characteristics of this region illustrates the potential benefits of siting natural gas-fired generation as a transmission alternative.

Fort Nelson/HRB

As described in Chapter 2, the Fort Nelson region is a non-integrated area currently served by local natural gas-fired generation. The nearby HRB is a region with significant natural gas production potential. A portion of the gas extraction process could be electrified leading to significant growth of the electrical load in the area. Natural gas-fired generation offers a potentially cost-effective alternative to B.C.- or Alberta-based transmission but may use part or all of the 7 per cent non-clean headroom. The relative cost-effectiveness of various supply strategies and available gas head room are dependent on market scenario and the load scenarios for the Fort Nelson/HRB region. The results of BC Hydro's analysis for the Fort Nelson/HRB region are summarized in section 6.6.

Lower Mainland/Vancouver Island

The Lower Mainland/Vancouver Island region accounts for approximately 70 per cent of BC Hydro system load. Only around 25 per cent[22] of the peak Lower Mainland/Vancouver Island load can be met by resources within the region, meaning most of its capacity requirement is met via transmission. Future sources of capacity in the Lower Mainland/Vancouver Island region other than natural gas-fired generation, such as pumped storage facilities, have significant uncertainties in terms of development and operations. As discussed in section 6.8.4.1, if pumped storage

[22] Excluding Burrard capacity.

facilities in the Lower Mainland/Vancouver Island are not available, an additional line from the Interior to Lower Mainland after 5L83 may be required by F2029 under a large gap condition. This next line can be avoided or delayed by siting gas-fired generation in Lower Mainland/Vancouver Island region. However, siting gas-fired generation in the Lower Mainland would be very challenging from a permitting perspective, as discussed in section 6.2.5.

South Peace Region

Section 2.5 identified substantial growth potential in the South Peace region as the natural gas industry develops unconventional gas reserves in the Montney gas basin. The high-load growth expectation has triggered the need for transmission upgrades and additions in this area.

In April 2013, the BCUC granted a CPCN for BC Hydro's Dawson Creek to Chetwynd Area Transmission Project (**DCAT**), which is designed to address electricity supply constraints in the Dawson Creek and Groundbirch areas within the South Peace region. While DCAT will increase both N-0 and N-1 regional load serving capabilities, BC Hydro's load forecast indicates additional supply will be needed.

The use of natural gas-fired generation as an alternative to network transmission upgrades (DCAT plus future transmission additions) were assessed as part of the DCAT CPCN application process. The assessment concluded the transmission alternatives were generally more cost-effective and reliable than the comparable natural gas-fired generation alternatives. There were a number of factors that contributed to this conclusion:

- Using natural gas-fired generation would require the installation of relatively small units (50 MW to 75 MW) to have redundancy such that an acceptable level of reliability can be achieved. Such redundancy is required to allow for both planned outages (maintenance) and unplanned outages (breakdowns) of generating units.

- The use of small natural gas-fired units, even if configured as CCGTs, has cost inefficiencies relative to larger unit sizes because of higher unit capital costs, and higher operating costs associated with the additional maintenance required for multiple unit configurations. There are also operational inefficiencies for the smaller CCGT units since they generally have lower thermal efficiencies (higher heat rates) compared to the larger units.
- There are further inefficiencies (e.g., operation at partial unit loadings and uneconomic dispatch) associated with the need for "reliability must run" operation of the local units to ensure that an acceptable level of reliability is maintained

This IRP does not provide an updated analysis for the South Peace region that compares future transmission additions to local natural gas-fired generation. Such analysis will be included in any future CPCN application for area reinforcements needed to meet the supply gap identified in section 2.5.5. However, given the drawbacks identified above, as well as broader system considerations associated with optimal use of the 7 per cent gas head room, further reinforcement of the South Peace region transmission system is expected to be the preferred supply option.

6.2.7.2 Using Gas as a Capacity and Contingency Resource

Most of the low-cost hydro capacity options that were available to BC Hydro have now been developed to meet load growth. Revelstoke Unit 5 is now operational while Mica Units 5 and 6 are currently under construction. Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and Site C are the only remaining large-scale hydroelectric capacity options available to BC Hydro. Site C is in the BRP to meet capacity need under the mid gap condition (see section 6.4 and section 6.9 for more details, and section 9.2.6). However, it is also a large project with regulatory uncertainty. Revelstoke Unit 6 (488 MW) and GMS Units 1-5 Capacity Increase (up to 220 MW) together are not sufficient to replace Site C's 1,100 MW of dependable capacity in the event of a delay in the Site C earliest in-service date (**ISD**) of F2024. Furthermore, as identified in section 6.9, the contingency conditions considered by BC Hydro for planning purposes could require BC Hydro to use up all of its large-scale hydroelectric options.

Capacity options other than natural gas-fired generation and the ones listed above have significant development and operational uncertainties. Pumped storage has been identified as a sizeable source of clean capacity in B.C. with an estimated lead time of eight to 10 years. However, pumped storage has not yet been permitted or developed in B.C., and thus significant uncertainties exist around the permitting process and development timelines. Furthermore, as shown in Table 6-3, pumped storage hydro is significantly more expensive than SCGTs. DSM capacity options are limited in potential and have implementation and operational uncertainties as discussed in section 3.7.4 and section 6.9.

Natural gas-fired generation has a relatively short construction lead time once permitting is secured. Siting flexibility may also exist, provided gas supply is available and required permitting can be secured. Hence, given the lack of other capacity alternatives that can act as contingency resources, there is added value for reserving natural gas-fired generation for contingency situations. Developing peakers instead of base loaded gas-fired units would maximize the dependable capacity that is available for contingency purposes. Figure 6-2 shows that the available capacity increases from about 100 MW to 600 MW by around F2024, if natural gas-fired generation is built for capacity (i.e., SCGT) rather than energy (i.e., CCGT).

BC Hydro has compared a portfolio that uses the 7 per cent non-clean headroom for capacity in combination with clean or renewable IPP resources instead of Site C to a portfolio that uses the 7 per cent non-clean headroom when an energy or capacity gap re-emerges after Site C. The 2012 mid-load Forecast without LNG was used in this analysis. Natural gas-fired units were assumed to be located in the Kelly Lake region close to a major natural gas pipeline. The results of the portfolio analysis are shown in section 6.4. The analysis shows that the portfolio of building Site C, and utilizing the 7 per cent non-clean headroom in subsequent years is more cost-effective. The option value of being able to reserve natural gas-fired generation as a contingency resource in the face of future uncertainties is an added benefit that is not captured in this analysis.

6.2.8 Conclusions

Planning to meet the 93 per cent clean or renewable objective under average water conditions is consistent with the objectives of the *CEA*.

Natural gas-fired energy has a cost advantage over other resources given current gas prices as well as under most Market Scenarios. However, using natural gas-fired generation primarily for capacity, while potentially siting it as a transmission alternative (to benefit from transmission deferral/avoidance) and reserving it as a contingency resource, allows BC Hydro to optimize the use of the 7 per cent non-clean headroom.

In considering the siting of natural gas-fired generation, BC Hydro identified several regions other than the Kelly Lake area which is close to a major gas pipeline. The siting of natural gas-fired generation in these other regions (i.e., North Coast, Fort Nelson/HRB, and Lower Mainland/Vancouver Island) may yield significant transmission deferral benefits. The South Peace region is an area where the need to build and operate small, redundant natural gas-fired units is expected to result in transmission being the preferred supply option. Natural gas-fired generation has a relatively short construction lead time. However, permitting can be challenging especially in locations such as the Lower Mainland. Lengthy permitting requirements can potentially preclude the use of natural gas-fired generation as a contingency resource or as an alternative to transmission. BC Hydro should explore the natural gas-fired supply options to reduce potential delays to siting gas and preserve the value that is offered by natural gas-fired generation.

The conclusions on this natural gas-fired generation section support Recommended Actions 11 and 17 described in Chapter 9.

6.3 Demand Side Management

6.3.1 Introduction

The energy resource options for BC Hydro to meet long-term needs are DSM, Site C, and clean or renewable IPPs. BC Hydro analyzes DSM first to meet the *CEA* objective of reducing at least 66 per cent of load growth by 2020 (i.e., F2021) using DSM and because, as shown in Chapter 3, it is a low-cost resource option with a low environmental footprint. Section 4.2.5.2 established the preferred means of achieving savings through short-term adjustments to DSM Option 1 and Option 2/DSM Target[23]. The analysis in this chapter compares the adjusted DSM Options 1 and 2, and DSM Option 3 described in section 3.3.1, to each other, and to supply-side resources such as Site C and clean or renewable IPPs to determine the most cost-effective resource mix and answer the following questions:

- Should the long term DSM target established in the 2008 LTAP be adjusted?
- Should BC Hydro continue to advance Site C for its earliest ISD of F2024?

The analysis jointly considers the continued cost-effectiveness of Site C and the appropriate DSM reliance to minimize short-term costs while continuing to provide cost-effective long-term savings. The cost-effectiveness of Site C is further tested in section 6.4.

[23] Note that short-term adjustments are already reflected in these options as shown in Chapter 3.

6.3.2 Resource Need: DSM Options and Load-Resource Balance

The three analyzed DSM options differ based upon increasing program activities in moving from Option 1 to Option 2/DSM Target to Option 3. As described in Chapter 4, low (about P10), mid and high (about P90) levels of savings were assessed for Option 2/DSM Target to reflect the quantifiable uncertainty of forecasted DSM savings.

Table 6-5 shows the mid savings level associated with these three DSM options for F2021 and their ability to reduce the load growth per the *CEA* objective. Table 6-5 also shows the per cent of load growth numbers with and without Expected LNG; however, the analysis in this chapter reflects the need for resources prior to including Expected LNG. The ability to supply Expected LNG loads is further reviewed in section 6.5.

Table 6-5 Mid Savings Levels for DSM Options and per cent of Load Growth

DSM Option	Mid Savings in F2021 (GWh/year)	% of Load Growth without Expected LNG	% of Load Growth with Expected LNG
Option 1	6,100	67	58
Option 2/DSM Target	7,800	78	69
Option 3	8,300	82	72

Figure 6-3 and Figure 6-4 show the remaining load-resource gaps (mid gap) after implementing each of these DSM options in a no LNG scenario. These remaining gap sizes would inform the need for supply-side resources once a level of DSM is selected.

Figure 6-3 Energy Gap after DSM Options 1 to 3 (Mid gap)

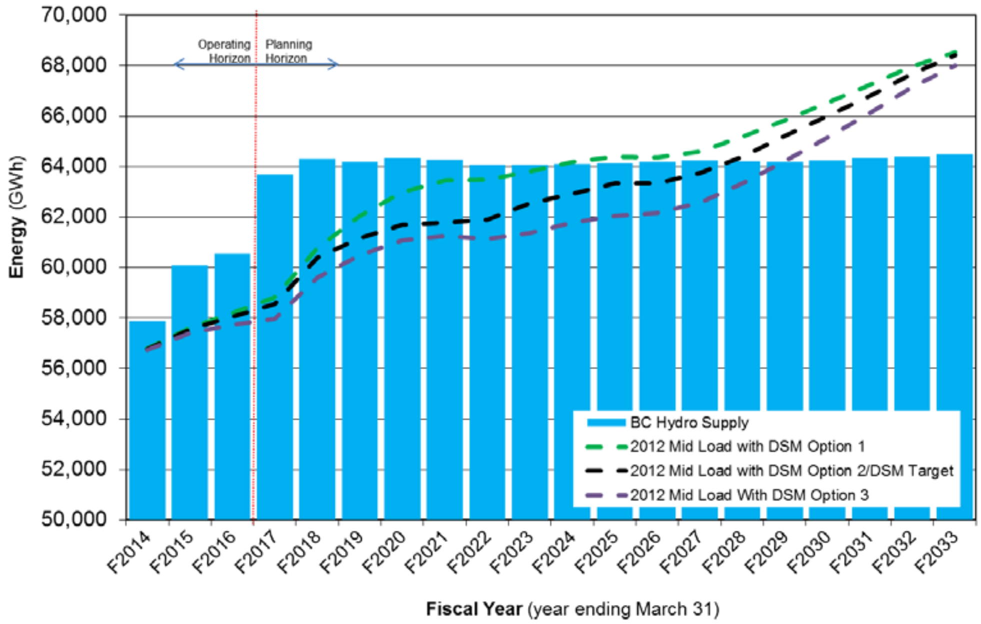
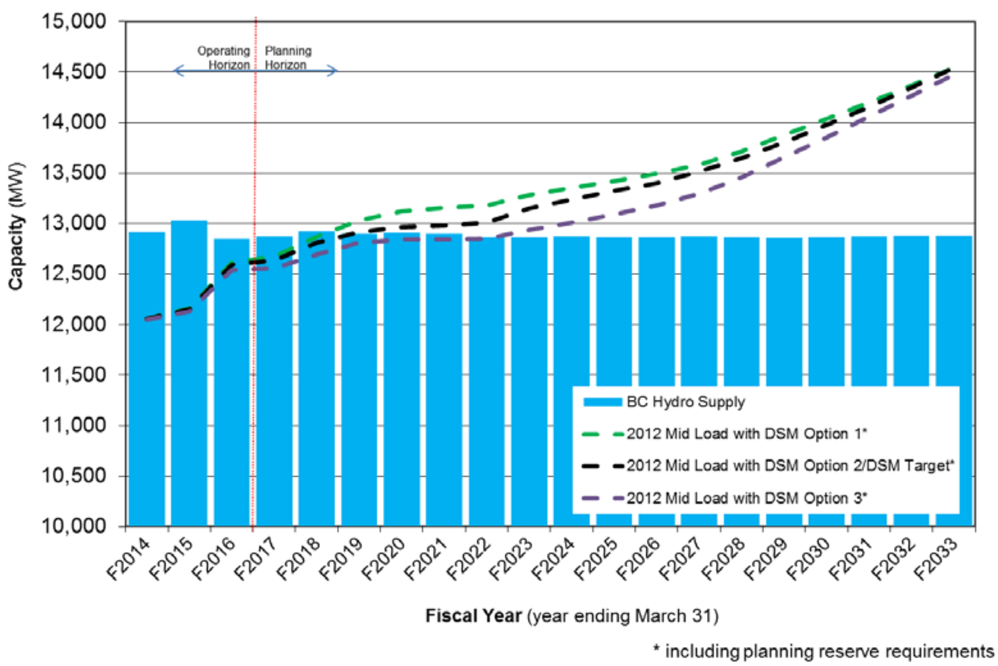


Figure 6-4 Capacity Gap after DSM Options 1 to 3 (Mid Gap)



6.3.3 Financial Factors: Cost of DSM Options

As described in section 3.3.4.1, there are two cost-effectiveness tests for DSM: Total Resource Cost (**TRC**) and Utility Cost (**UC**).

The TRC test measures the overall economic efficiency of a DSM initiative from a resource options perspective based on its total cost including both customer participant and the public utility's costs, and is the primary test used in BC Hydro's portfolio modelling analysis described in Chapter 6. The TRC used in the PV of the portfolios is net of (i.e., lowered by):

- Associated regional transmission and distribution capacity benefits. The generation and bulk transmission capacity benefits are not netted off (subtracted off) the TRC because the associated avoided cost is already captured by comparing portfolios created by System Optimizer which select generation and bulk transmission resources to meet the requirement of the portfolios.
- Non-energy benefits (e.g., operation and maintenance savings resulting from the installation of an energy efficient measure) and natural gas savings benefits as estimated by BC Hydro.[24] These benefits are estimated to result in about a $4/MWh reduction for the TRC for DSM elements that provide non-energy benefits and/or natural gas benefits.

As described in section 3.3.3.1, all three DSM options have low average gross TRCs (i.e. before netting off any benefits) ranging from $32/MWh to $35/MWh. Among the three DSM tools (i.e., codes and standards, rates structure and programs), programs have the highest cost. It is important to recognize that while the average cost of each

[24] The Demand-Side Measures Regulation guides the BCUC's adjudication of section 44.2 *Utilities Commission Act* DSM expenditure filings. The Demand-Side Measure Regulation provides a deemed value for natural gas savings and a deemed non-energy benefit adder of 15 per cent. These deemed values are not reflected in the portfolio analysis. The Demand-Side Measure Regulation is not legally binding on BC Hydro. The test for the IRP is "good utility practice" as set out in subsection 3(1) if the *CEA*. BC Hydro's estimate of these benefits amounts to about $4/MWh. BC Hydro's TRC methodology is consistent with good utility practice as generally reflected among other things in the California Standard Practice Manual.

DSM option is low (compared to \$94/MWh[25] and above for supply-side resources), each option is comprised of DSM programs with a wide range of costs. For example, DSM target programs have net TRC costs[26] ranging from \$6/MWh to \$113/MWh (see section 9.2.1.1).

Both the TRC and UC perspectives are considered in determining the short-term energy supply management described in Chapter 4 and in evaluating the recommended DSM plan described in section 9.2.1.

6.3.4 Portfolio Analysis

In this analysis, different portfolios of DSM options and supply side (Site C and clean or renewable IPPs) resources to fill LRB gaps are created, and the PVs of the costs of these portfolios are compared. This analysis is done using the base assumptions shown in Figure 6-5[27] unless otherwise noted.

[25] Site C cost adjusted to Lower Mainland but before netting off capacity benefits.

[26] The net TRC quoted is net of generation, transmission and distribution capacity benefits, non-energy benefits and natural gas savings benefits.

[27] For the 30-year portfolio analysis, DSM savings were extended from the underlying 20-year DSM options using two methods: 1) reflecting the most current thinking where the last year of cumulative savings was held to be constant; and 2) savings continue to grow based on the rate of growth averaged over the last five years. Portfolios comparing DSM options used the "constant savings" assumption. For the rest of the analysis, the latter "extrapolation" assumption was used.

Figure 6-5 Modelling Assumptions

Modelling Map					
Uncertainties/Scenarios					
Market Prices	Scenario 2 Low	Scenario 1 Mid	Scenario 3 High		
Load Forecast	Low	Mid	High		
DSM deliverability	Low	Mid	High		
LNG Load Scenarios	Prior to Expected LNG	800 GWh	3000 GWh	6600 GWh	
Resource choices					
Usage of 7% non-clean	Yes	No			
Site C (all units in) timing	F2024	F2026	No Site C		
Modelling Assumptions and Parameters					
BCH/IPP Cost of Capital	5/7	5/6			
Pumped Storage as Option	Yes	No			
Site C Capital Cost	Base minus 10%	Base	Base plus 10%	Base plus 15%	Base plus 30%
Capital Cost for alternatives to Site C	Base	Base plus 30%			
Wind Integration Cost	$5/MWh	$10/MWh	$15/MWh		
	shows the modeling assumptions				

6.3.4.1 Option 2/DSM Target with and without Site C

The initial analysis tests whether Site C continues to be a cost-effective resource given the current BC Hydro DSM target (Option 2). Option 2/DSM Target provides sufficient energy leading up to Site C's earliest ISD while allowing for a reduction in near-term program expenditures.

The analysis shows that the portfolio with Site C has a PV benefit of $630 million[28] over a clean or renewable resource portfolio without Site C and a benefit of $150 million over a portfolio that maximizes the use of the 7 per cent natural gas headroom, meaning Site C is a cost competitive resource after implementation of the

[28] Note that the DSM savings of Option 2 used in the Site C analysis was extended from 20 years to 30 years using the "extrapolation" assumption as described in the footnote in section 6.3.4. That analysis resulted in a $630 million benefit for Site C. If the "constant savings" assumption is used, the Site C benefit increases to $750 million. Apart from the $630 million and $150 million quoted in section 6.3.4.1, all other PV numbers or differences quoted in section 6.3 are based on portfolios with DSM savings extended using the "constant savings" assumption.

Option 2/DSM Target. The cost-effectiveness of Site C given the current Option 2/DSM Target is further analyzed in section 6.4.

6.3.4.2 DSM Option 3

The next analysis was to determine if DSM Option 3 would be a lower-cost potential alternative to Site C. DSM Option 3 on its own would only defer the need for Site C's energy output for three years (from F2028 to F2031, without Expected LNG). To be an alternative to Site C, DSM Option 3 must be augmented with additional supply-side resources to match Site C's energy and dependable capacity output. The most cost-effective alternative to Site C would include the use of natural gas-fired generation up to the 7 per cent non-clean headroom. The results show that the portfolio with Option 2/DSM Target and Site C has a PV cost benefit of $330 million compared to the portfolio with Option 3, natural gas-fired generation within the 7 per cent headroom, low cost Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase capacity resources but without Site C.

A portfolio with Option 3 was also compared to a portfolio with Option 2/DSM Target, both with Site C and no natural gas-fired generation option. The comparison shows that given Site C, staying with Option 2/DSM Target would avoid costly surplus and has a $280 million lower PV cost than DSM Option 3.

The ability to supply Expected LNG load given DSM Option 2/DSM Target and Site C without adding additional energy resources is discussed in section 6.5 and demonstrates that DSM Option 3 would not be cost-effective at this time even with Expected LNG.

6.3.4.3 DSM Option 1

The Option 2/DSM Target analysis concluded that a portfolio with Site C was more cost-effective than a portfolio without Site C. Given that Site C is a cost-effective resource and is continuing to be advanced, the next question is whether it would be more cost-effective to reduce the DSM target to Option 1, which meets the minimum 66 per cent load reduction objective of the *CEA*.

The portfolio with Option 2/DSM Target has a $110 million PV benefit compared to portfolio with Option 1. Both portfolios include Site C. These portfolios show that although Option 2/DSM Target results in more surplus, the incremental savings from Option 1 to Option 2/DSM Target is cost competitive against market prices, making the portfolio with Option 2/DSM Target lower cost.

Furthermore, reducing the DSM target is risky at this time. Site C is a large project and faces regulatory approval uncertainty. Reducing the DSM target before Site C's development is secured could create a greater need for more costly supply-side resources such as clean or renewable IPPs. In a scenario without Site C, the portfolio with Option 1 would be $340 million more costly than portfolio with Option 2/DSM Target. In the Expected LNG scenario, the energy deficit before Site C would increase by about 1,300 GWh to 2,300 GWh/year if the target for DSM is reduced to Option 1.

6.3.5 Deliverability Risks

The deliverability risk/uncertainties around DSM are discussed in section 4.3.4.2. An unexpected downward departure from the planned level of DSM savings is a reliability concern, particularly with respect to capacity. With Option 2/DSM Target, BC Hydro would be relying on DSM to deliver 1,400 MW of dependable capacity by F2021 (i.e., 86 per cent of incremental peak load growth from F2013). Based on the DSM uncertainty quantified by BC Hydro as described in section 4.3.4.2, there is about 10 per cent probability that the DSM Plan will deliver about 300 MW less than the 1,400 MW DSM target by F2021.

DSM deliverability risk is further assessed in section 6.9 dealing with capacity and contingency plans.

6.3.6 Environmental and Economic Development Benefits

DSM avoids the environmental impacts associated with the construction of new generation facilities. Incremental DSM also provides economic development benefits through the creation and retention of jobs and increased Gross Domestic Product (**GDP**).

6.3.7 Conclusions

Option 2/DSM Target is the most cost-effective long-term target at this time. DSM Option 3 is not a cost-effective alternative to Site C or to the DSM target. Lowering the DSM target level to DSM Option 1 is not cost-effective. It is also too risky to pursue at this time given the approval uncertainty associated with Site C and potential LNG load.

Conclusions in this DSM section support Recommended Action 1, as described in section 9.2.

6.4 Site C

6.4.1 Introduction

Site C would provide approximately 1,100 MW of dependable capacity, and approximately 4,700 GWh and 5,100 GWh of firm energy and average energy per year, respectively. The earliest ISD for Site C would have the first unit in operation by December 2022 and all units in place by F2024. This would allow the full capacity of Site C to be relied upon during the peak load winter season of F2024.

The key question for Site C in the IRP is:

- Should BC Hydro continue to advance Site C for its earliest ISD?

To assess Site C's cost-effectiveness relative to other available resource options, portfolios including Site C[29] were compared against portfolios that did not include Site C. Two general portfolio categories were analyzed:

- Clean Generation Portfolios: these portfolios use a combination of clean or renewable resources including wind, biomass and run-of-river hydro. Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and, lastly, pumped storage capacity projects as needed to meet the capacity requirement of the portfolios. These portfolios reserve the 7 per cent non-clean headroom for contingency use as described in section 6.2.
- Clean + Thermal Generation Portfolios: the resource options in these portfolios are the same as the Clean Generation Portfolios except that thermal generation (in the form of SCGTs) within the 7 per cent non-clean headroom is available as soon as it is needed to meet capacity requirements. These portfolios provide the most stringent cost competitiveness tests for Site C by advancing low-cost natural gas-fired generation capacity. However, BC Hydro does not support this approach because it foregoes the ability and benefits of using natural gas-fired generation as a contingency resource (refer to section 6.2 for more details).

The cost competitiveness of Site C is evaluated using two different methods of portfolio analysis:

1. **Unit Cost Comparison/Block Analysis:** The first method is a unit cost comparison whereby the cost of Site C is compared to the cost of similar-sized blocks of energy and capacity provided by alternative resources. The block comparison compares Site C to its alternatives over their project lives and demonstrates the long-term value of Site C.
2. **Portfolio Analysis Using System Optimizer:** The second method creates and evaluates portfolios using the linear optimization model (System Optimizer) that

[29] The Site C cost used in the analysis does not include sunk costs.

selects the optimal combinations of resources over a 30-year planning horizon under different assumptions and constraints. The analysis using System Optimizer is a more sophisticated approach and provides additional information not captured by the simple unit cost comparison, including:

- Timing of resource additions and associated capital expenditures
- Effects of resource additions to the overall system and the system LRB over the planning horizon
- Expected operating costs and economic dispatches reflecting the manner in which the resources will be operated
- Electricity market trade benefits depending on the flexibility of the overall portfolio.

The portfolios analyzed in this section assume DSM at the Option 2/DSM Target savings level. The cost competitiveness of Site C compared to DSM Option 3 is analyzed in section 6.3.

The simple unit cost comparison is presented in section 6.4.2. Portfolio analysis using System Optimizer is presented in section 6.4.3 and section 6.4.4 for the base assumptions and sensitivity tests, respectively. Section 6.4.5 describes other technical benefits of Site C. Comparisons of the environmental and economic development attributes for portfolios with and without Site C are presented in section 6.4.6 and section 6.4.7, respectively. Conclusions are presented in section 6.4.8.

6.4.2 Unit Cost Comparison (Block Analysis)

The alternatives to Site C are composed of multiple available resources, as most alternative resources are not capable of delivering comparable amounts of energy and dependable capacity on their own. To facilitate a unit cost comparison with Site C, a portfolio of clean generation resources and a portfolio of clean + thermal generation resources both making up to Site C's 5,100 GWh/year of energy and

1,100 MW of dependable capacity are created and the adjusted UECs are compared. Two variations of the Clean + Thermal Generation portfolio are considered. One variation uses the entire 7 per cent non-clean headroom of six SCGTs around F2024 together with Revelstoke Unit 6 to meet the 1,100 MW capacity requirement. The other variation replaces two of the SCGTs with GMS Units 1-5 Capacity Increase. The adjusted UEC costs for all four portfolios are listed in Table 6-6, showing that Site C is lower cost than the alternative portfolios.

Table 6-6 Comparison of Adjusted UECs

	Site C	Clean Generation Block (Revelstoke Unit 6, GMS and Pumped Storage)	Clean + Thermal Generation Block (Revelstoke Unit 6 and 6 SCGTs)	Clean + Thermal Generation Block (Revelstoke Unit 6, GMS and 4 SCGTs)
$/MWh	94[30]	153	128	130

It should be noted that the adjusted UECs[31] for the Clean Generation and the Clean + Thermal Generation blocks shown in Table 6-6 differ from the adjusted UECs described in Chapter 3. For comparison purposes, the cost of capacity resources required to make clean or renewable IPP resources have Site C's equivalent capacity are included in the adjusted UECs shown in Table 6-6. UECs in this chapter add capacity costs for resource options that do not have dependable capacity, while UECs in Chapter 3 reduce the cost of resource options which do deliver dependable capacity by the cost of avoided capacity options. The net effect is roughly equivalent for both analysis techniques. The adjusted UECs in Chapter 3 also have not reflected network upgrade costs (estimated at $6/MWh).

Table 6-7, Table 6-8 and Table 6-9 show the resources, which make up the Clean Generation and Clean + Thermal Generation blocks, and their associated costs.

[30] This is Site C's unit energy cost (excluding sunk cost) adjusted for delivery to the Lower Mainland before taking into account a capacity credit. The corresponding cost after a capacity credit is $83/MWh.

[31] Adjusted UEC is the appropriate measure to use when comparing resource options as it adjusts the generation resources to be a common firm energy product delivered to BC Hydro's major load centre, the Lower Mainland. Adjusted UECs are calculated based on the firm energy provided by the resource options, and adjustments are made to reflect delivery costs to the Lower Mainland, wind integration costs (where applicable), capacity credit, soft costs and time of delivery of the energy.

These blocks predominately consist of wind resources to provide energy. In the Clean Generation block, Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and pumped storage are added to the block to make the capacity equivalent to Site C. To account for the energy losses associated with pumped storage, this block requires 364 GWh/year of additional energy resources. In the Clean + Thermal Generation blocks, SCGTs partly make up the capacity need comparable to Site C. As described in section 6.2, BC Hydro would plan on SCGTs to run about 18 per cent of the time if used as a capacity/peaking resource. As a result, SCGTs would contribute towards the 5,100 GWh/year of energy to be equivalent to Site C, and thus the need for clean or renewable energy such as wind would be reduced to 4,180 GWh/year and 4,490 GWh/year for the six SCGTs and the four SCGTs blocks, respectively.

Table 6-7 Details and UEC Calculations for the Clean Generation Block

Clean Generation				
Project Name	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($F2013M)
Energy Costs				
MSW2_LM	25	211	90	19
Wind_PC28		591	121	71
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	13
Wind_PC19		441	124	55
Wind_PC16		377	126	48
Wind_PC14		527	127	67
Wind_PC10		1023	129	132
Wind_PC15		382	130	50
Wind_PC20		609	131	80
Wind_VI12		151	131	20
Wind_VI14		113	132	15
REV6 Variable Costs (see note 1)	n/a	26	12	0
GMS Variable Costs (see note 2)	n/a	0	0	0
PS Variable Costs (see note 3)	n/a	(364)	19	7
Weighted Average excluding capacity resources	n/a	n/a	**125**	n/a
Weighted Average including capacity resources	n/a	n/a	**135**	n/a
Sub-total	36	5100	n/a	688
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	Total Cost ($F2013M)
REV6 Fixed Costs	488	n/a	50	24
GMS Fixed Costs	220	n/a	35	8
PS Fixed Costs	500	n/a	124	62
Sub-total	1208	n/a	78	94
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($F2013M)
Total	1244	5100	**153**	782

Note:

1. REV6 variable cost include variable OMA and water rentals.
2. The GMS cost is a conceptual level estimate and a variable component has not been calculated but is expected to be less than the variable component for Revelstoke Unit 6 ($0.3M).
3. Pumped Storage variable cost include variable OMA and water rentals. The cost of energy losses is included in the total cost of the clean resources that would be used to serve those losses.
4. UECs include a soft cost adder of 5%, wind integration cost where applicable, adjustment for time of delivery, a regional transmission cost adder of $6/MWh, and the cost of delivery to the lower mainland.

Table 6-8 Details and UEC Calculations for the Clean + Thermal Generation Block (Revelstoke Unit 6 and 6 SCGTs)

Clean + Thermal Generation (No GMS, 6 SCGTs)				
Project Name	Dependable Capacity (MW)	Annual Firm/Effective Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($1000)
Energy Costs				
MSW2_LM	25	211	90	19
Wind_PC28		591	121	71
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	13
Wind_PC19		441	124	55
Wind_PC16		377	126	48
Wind_PC14		527	127	67
Wind_PC15		382	130	50
Wind_PC20		609	131	80
REV6 Variable Costs (see note 1)	n/a	26	12	0
SCGT Variable Costs (see note 2)	n/a	924	66	61
Weighted Average excluding capacity resources	n/a	n/a	**124**	n/a
Weighted Average including capacity resources	n/a	n/a	**113**	n/a
Sub-total	36	5101	n/a	575
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	Total Cost ($F2013M)
REV6 Fixed Costs	488	n/a	50	24
SCGT Fixed Costs	588	n/a	88	52
Sub-total	1076	n/a	71	76
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($F2013M)
Total	1112	5101	**128**	651

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

Table 6-9 Details and UEC Calculations for the Clean + Thermal Generation Block (Revelstoke Unit 6, GMS and 4 SCGTs)

Clean + Thermal Generation (With GMS, 4 SCGTs)				
Project Name	Dependable Capacity (MW)	Annual Firm/Effective Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($1000)
Energy Costs				
MSW2_LM	25	211	90	19
Wind_PC28		591	121	71
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	13
Wind_PC19		441	124	55
Wind_PC16		377	126	48
Wind_PC14		527	127	67
Wind_VI14		113	132	15
Wind_PC11		473	133	63
Wind_PC09		713	133	95
REV6 Variable Costs (see note 1)	n/a	26	12	0
GMS Variable Costs (see note 2)	n/a	0	0	0
SCGT Variable Costs (see note 3)	n/a	616	66	41
Weighted Average excluding capacity resources	n/a	n/a	**125**	n/a
Weighted Average including capacity resources	n/a	n/a	**117**	n/a
Sub-total	36	5102	n/a	598
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	Total Cost ($F2013M)
REV6 Fixed Costs	488	n/a	50	24
GMS Fixed Costs	220	n/a	35	8
SCGT Fixed Costs	392	n/a	88	34
Sub-total	1100	n/a	60	66
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($F2013M)
Total	1136	5102	**130**	665

Note:

1. REV6 variable cost include variable OMA and water rentals.
2. The GMS cost is a conceptual level estimate and a variable component has not been calculated but is expected to be less than the variable component for Revelstoke Unit 6 ($0.3M).
3. SCGT variable costs include variable OMA, fuel cost and GHG cost.
4. UECs include a soft cost adder of 5%, wind integration cost where applicable, adjustment for time of delivery, a regional transmission cost adder of $6/MWh, and the cost of delivery to the lower mainland.

6.4.3 Portfolio Analysis using System Optimizer – Base Case

This analysis evaluates the cost competitiveness of Site C by comparing the PV cost of portfolios with and without Site C using the System Optimizer. Positive values indicate that the portfolio with Site C has lower costs than the alternative portfolio. Figure 6-6 shows the base assumptions/conditions used for the portfolios analyzed in this section. [32]

BC Hydro undertook portfolio analysis for Site C using two potential ISDs – F2024 and F2026. F2024 represents the earliest ISD for the Site C based on the current schedule. F2026 was used as a second ISD as this is the time period over which the characteristics of Site C could reasonably assumed to be consistent. Delaying Site C beyond F2026 would not allow for consistent comparison as it would likely require an update to the regulatory process, a review of the Site C cost estimate and re-work of the construction schedule.

It should be noted that portfolio PV modelling using a F2026 Site C ISD does not consider several real costs of deferral including:

- incremental carrying costs for maintaining core project staff for two years
- costs of repeated engineering work (where new engineering team members require new studies to accept design responsibility)
- additional interest during construction (additional financing costs for two years, additional IDC paid on direct costs, plus impact of shifting spending to periods with higher forecast interest rates)

[32] For 30-year portfolio analysis, DSM savings were extended from the underlying 20-year DSM options using two methods: 1) reflecting the most current thinking where the last year of cumulative savings was held to be constant; and 2) savings continue to grow based on the rate of growth averaged over the last five years. Portfolios comparing DSM options used the “constant savings” assumption. For the rest of the analysis, the latter “extrapolation” assumption was used. When creating portfolios to stress test the cost-effectiveness of Site C, the “extrapolation” assumption was used as it gives advantage to the alternatives of Site C by allowing them to be built later given higher level of DSM savings.

In addition to cost, deferral would also increase the probability and/or consequences of several risks, such as:

- Added market risk due to the additional time of risk exposure (e.g., risk to financing rates, commodity prices, labour costs, etc.)
- Loss of market interest for procurement and resulting lower competition (for example, 1 per cent of direct construction cost is ~$40 million in real dollars)
- Loss of key staff to attrition, and resulting cost and time requirements to hire new staff and familiarize them with the Project
- Requirements to complete all or a portion of the environmental assessment process

A significant deferral in project schedule could result in the requirement to repeat some or all of the regulatory process, with accompanying costs and delays. Subsection 18(1) of the *BCEAA* provides that an EAC must specify a deadline of between three to five years after the issue date of the EAC by which the holder of the EAC must have 'substantially started the project'. The current schedule foresees an approximately seven year construction period to first power, with an additional year for final project commissioning and reclamation, based on the assumptions that: 1) BC Hydro is successful in obtaining an EAC by the end of 2014; 2) fulfilling the Crown's duty to consult and where appropriate accommodate First Nations; and 3) the BC Hydro Board of Directors and Province approvals to proceed to construction as part of their respective investment decisions. Based on this, under the EAC BC Hydro would have to have 'substantially started' construction by 2017 to 2019, with a latest ISD of F2027 for all six generating units. As a result, delaying Site C beyond F2026 would likely require a new Environmental Assessment process, with accompanying First Nation consultation and stakeholder engagement. The cost associated with undertaking a new environmental assessment for the project would be in the range of $200 to $300 million.

Figure 6-6 Base Modelling Assumptions Used for the Site C Portfolio Analysis

Modelling Map					
Uncertainties/Scenarios					
Market Prices	Scenario 2 Low	Scenario 1 Mid	Scenario 3 High		
Load Forecast	Low	Mid	High		
DSM deliverability	Low	Mid	High		
LNG Load Scenarios	Prior to Expected LNG	800 GWh	3000 GWh	6600 GWh	
Resource choices					
Usage of 7% non-clean	Yes	No			
DSM Options	DSM Option 1	DSM Target/ Option 2	DSM Option 3		
Site C (all units in) timing	F2024	F2026	No Site C		
Modelling Assumptions and Parameters					
BCH/IPP Cost of Capital	5/7	5/6			
Pumped Storage as Option	Yes	No			
Site C Capital Cost	Base minus 10%	Base	Base plus 10%	Base plus 15%	Base plus 30%
Capital Cost for alternatives to Site C	Base	Base plus 30%			
Wind Integration Cost	$5/MWh	$10/MWh	$15/MWh		
	shows the modeling assumptions				

Table 6-10 shows the difference in the PV cost between the without Site C vs. Site C portfolios. Table 6-10 shows that Site C has a cost advantage at its earliest ISD, saving approximately $630 million and $150 million in PV as compared to the Clean Generation and Clean + Thermal Generation portfolios, respectively.

Note that the PV results shown for F2026 ISD have not taken into account any the potential costs of project delay. The costs of project deferral to F2026 are described above.

Table 6-10 Benefit of Site C compared to Alternative Portfolios (Basecase)

Portfolio Type	Site C Timing	Difference in PV Cost (Portfolio without Site C minus with Site C) ($2013 million)
Clean Generation portfolio	F2024	630
	F2026	880
Clean + Thermal Generation portfolio	F2024	150
	F2026	390

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

Note that BC Hydro has conservatively not assigned any value to surplus capacity. In the recent John Hart Generating Station Replacement Project CPCN proceeding, BC Hydro provided evidence that while the market value of capacity is uncertain because of illiquidity in the current Western Electricity Coordinating Council (**WECC**) region, BC Hydro estimated a range of market values of categories of about $75/kW-year to $110/KW-year, based on recent Bonneville Power Administration (**BPA**) tariffs, transaction and market analysis. BC Hydro further estimates that 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. These benefits associated with capacity surplus from Site C would add to its cost advantage described above.

It should also be noted that the partial replacement of the dependable capacity provided by Site C with SCGTs would use up all of the 7 per cent non-clean headroom. As a result, BC Hydro’s ability to use natural gas-fired generation for contingency resource planning purposes is forgone. This forgone value, which would increase the PV benefits of Site C over the Clean + Thermal Generation portfolio reported above, is not captured in the portfolio analysis undertaken.

6.4.4 Portfolio Analysis using System Optimizer - Sensitivities

In addition to the base assumptions/conditions analyzed, the IRP provides sensitivity analysis where key inputs are increased or decreased around their expected values to determine the impact on the cost competitiveness of Site C. These sensitivities included the LRB gap, BC Hydro/IPP cost of capital differential, market prices, Site C capital costs and wind integration costs. The IRP sensitivity analysis shows the impacts on the results when one variable is changed at a time. This process allows BC Hydro to determine which variables are the most influential and which are secondary – in this case, the LRB gap is the most influential variable, with market price and Site C capital cost as the next most influential variables.

In addition, the IRP analysis includes compound sensitivity analysis. Compound sensitivities combine sets of the variables that have the largest potential effect on cost-effectiveness, and are used to investigate more extreme potential outcomes of a decision. The IRP provides compound sensitivities reflecting the combined impacts of variability in the major drivers of Site C cost-effectiveness: LRB gap, market prices and Site C capital cost. Given this combination of low probability conditions, these compound sensitivity scenarios are ‘tails’ and are highly unlikely.

6.4.4.1 Load-Resource Balance Gaps

As described above, the portfolio modelling analysis uses System Optimizer, which captures the impact of variability in timing of resources as well as effects of resources on the BC Hydro system and trade benefits. In addition, portfolios with and without Site C are tested against large and small gap scenarios. To a large extent, this explores the value of flexibility inherent (or missing) in each type of resource in the portfolio:

- DSM – represents the most flexible resource in that it can be scaled up or down in an attempt to follow load growth trends. As set out in section 3.3.1, there are limits as to how quickly DSM can be ramped up and down. However, ramp rates were not used as constraints in this sensitivity analysis
- IPP Resources – are typically small and can be acquired in larger or smaller amounts in an attempt to match load as it trends upwards. The System Optimizer recognizes this by allowing individual IPP resources to be brought on-line individually and closely following load growth. However, such modelling

assumes perfect foresight and the use of constant project prices likely overstates the value of this flexibility in the analysis:

- Historically, BC Hydro has structured power acquisition processes to aggregate larger volumes to attract larger sized resources and achieve high levels of competition. These larger calls will not be able to match load growth as closely as assumed in the System Optimizer modelling
- Carrying out a series of smaller power acquisition processes and bilateral agreements, together with the imposition of Commercial Operation Date (**COD**) restrictions[33] to better match load, will likely impact pricing and restrict the type of projects that are bid
- Long-term take-or-pay contracts for intermittent clean or renewable resources limit the ability to ramp down volumes as recent experience has shown.

- Site C – is a large resource addition with a comparatively long lead time. The modelling of the small gap scenario captures the financial element of the regret of scheduling this resource in a case of reduced need. The inflexibility of this resource may be somewhat overstated in that there is a staged implementation process with decisions on whether to proceed at key points in the process. As described in section 9.2.6.2, should Site C be successful in environmental certification, investment decisions by BC Hydro's Board of Directors and the B.C. Government would be required prior to commencing construction. These investment decisions will consider relevant business factors related to the decision to begin construction of Site C.

The following large gap and small gap conditions, both assuming no LNG, are tested first:

[33] For example, the Clean Power Call had a six-year COD window (November 1, 2010 – November 1, 2016) designed to attract larger resources as feedback from the IPP community was that larger projects require extended CODs.

- Large gap conditions are defined as high-load forecast (about P90) with low level of DSM savings (DSM target at P10)
- Small gap conditions are defined as low-load forecast (about P10) and low level of DSM savings (DSM target at P10). As discussed in section 3.3.1, a reduced load forecast results in lower DSM savings.

Both conditions have a low probability of occurring (roughly 10 per cent each).

Figure 6-7 and Figure 6-8 show the LRB gap for large and small gap conditions prior to adding Site C. Table 6-11 summarizes the PV benefits for portfolios with Site C compared to portfolios without Site C 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; however, the small gap scenario has almost no load growth after DSM for most of the 30-year planning horizon.

Figure 6-7 Energy Load Resource Balance for Large, Mid and Small Gap

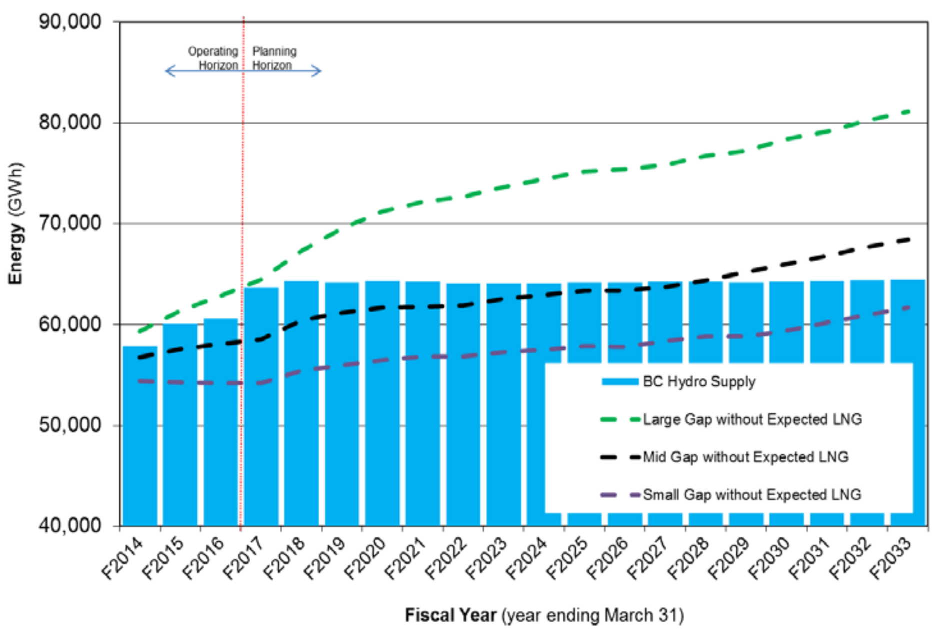


Figure 6-8 Capacity Load-Resource Balance for Large, Mid and Small-Gap

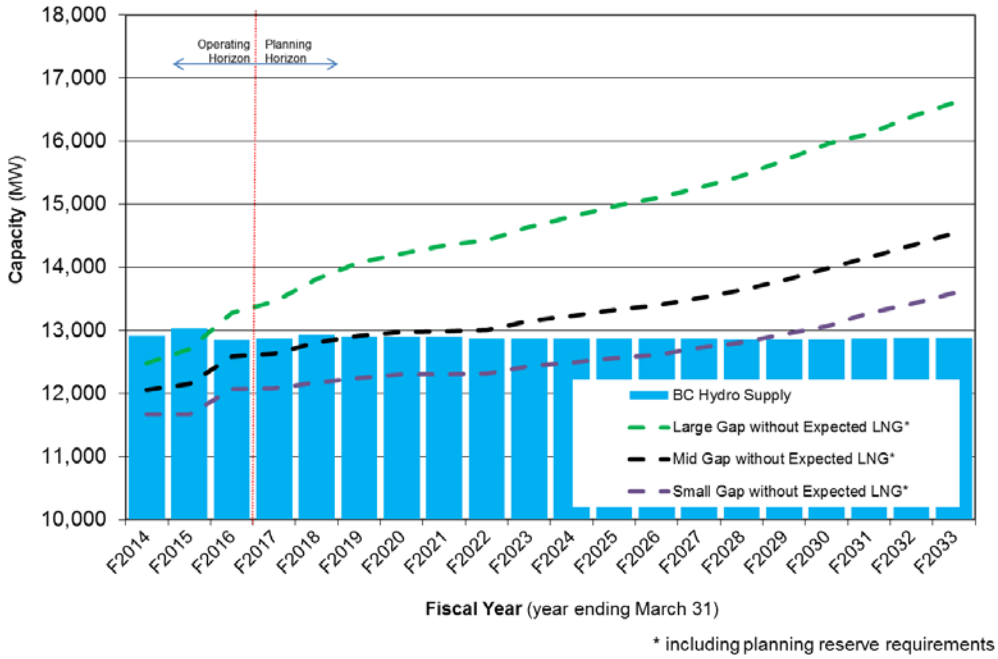


Table 6-11 Sensitivity of Site C Benefit to Gap Condition

Difference in PV Cost (Portfolio without Site C minus portfolio with Site C ($F2013 million))		Large gap (~10% likelihood)	Base Case: Mid gap (~80% likelihood)	Small-Gap (~10% likelihood)
Clean Generation Portfolio	F2024	Note 1	630	(1,040)
	F2026		880	(710)
Clean + Thermal Generation Portfolio	F2024	2,260	150	(1,280)
	F2026	Note 2	390	(910)

Note 1: As discussed in section 6.9, the large gap scenario is considered a contingency condition. As concluded in section 6.2, natural gas-fired generation within the 7 per cent non-clean headroom would be used for these conditions and therefore Clean-Only portfolios are not created for this gap. The benefits for Site C are expected to be higher in the Clean Only Portfolios than the Clean + Thermal Portfolios.

Note 2: The benefits for Site C are expected to be higher than the Clean + Thermal Generation Portfolio with Site C in F2024.

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

BC Hydro plans resource acquisitions based on its mid-load forecast. As discussed in section 4.3, DSM uncertainty and load uncertainty are then combined to arrive at the large and small gap scenarios. DSM under- and over-delivery is captured by the large and small gap variability. As discussed in section 4.3.4.2, BC Hydro is of the view that given the aggressiveness of the DSM target, there is likely more risk of under-delivery than of over-delivery. Table 6-12 and Table 6-13 show the variation in the size of the mid gap for the small gap and the large gap sensitivity analysis in F2021, F2024 and F2026.

Table 6-12 Difference between Mid Gap and Small/Large Gap – Energy (GWh)

	F2021	F2024	F2026
Small Gap	(4,949)	(5,445)	(5,520)
Large Gap	10,401	11,536	12,061

Table 6-13 Difference between Mid Gap and Small/Large Gap – Capacity (MW)

	F2021	F2024	F2026
Small Gap	(676)	(744)	(783)
Large Gap	1,368	1,567	1,699

While LNG proponents have the choice of whether to self-supply their energy requirements or request electricity service from BC Hydro, to the extent that LNG proponents take service, BC Hydro reviewed Expected LNG load in the context of Site C. Table 6-14 shows that the benefits of the portfolio with Site C would increase when Expected LNG load is considered. This is because Expected LNG advances the need for new energy resources after implementation of the DSM target and EPA renewals from F2028 to F2022 and does not change the timing of the requirement for new capacity resources (F2019).

Table 6-14 Sensitivity of Site C Benefit to LNG Scenario

Portfolio Type	LNG Scenario	F2024 Site C ISD Difference in PV Cost (Portfolio without Site C minus with Site C) ($F2013 million)
Clean Generation portfolio	No LNG	630
	Expected LNG	1,850
Clean + Thermal Generation portfolio	No LNG	150
	Expected LNG	1,260

6.4.4.2 Cost of Capital Differential

As described in section 3.2.2, the base assumption for cost of capital is 5 per cent for BC Hydro and 7 per cent for IPPs. A sensitivity test was performed assuming 6 per cent cost of capital for IPPs, effectively reducing the cost of capital differential from 2 per cent to 1 per cent. In this sensitivity test, the Site C portfolio with an ISD of F2024 maintains a cost advantage, although the benefit of the Site C portfolio is reduced from $630 million to $420 million for the Clean Generation portfolio, and from $150 million to $20 million for the Clean + Thermal portfolio. Refer to Table 6-15.

Table 6-15 Sensitivity of Site C Benefit to Cost of Capital Differential

Portfolio type	Cost of Capital for IPP (%)	Site C In-Service Date	Difference in PV Cost (Portfolio without the Project minus portfolio with the Project) ($2013 million)
Clean Generation	6	F2024	420
		F2026	670
Clean + Thermal Generation	6	F2024	20
		F2026	230

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

6.4.4.3 Market Prices

Market Scenario 1 is the base assumption used in the Site C analysis. Among the five market scenarios described in Chapter 5, it has the highest relative likelihood

(60 per cent) compared to the other market scenarios. In this section, the cost competitiveness of Site C is tested in a high market (Market Scenario 3) and a low market (Market Scenario 2) price scenario.

The PV benefits of Site C over the Clean Generation and Clean + Thermal Generation portfolios are shown in Table 6-16. In comparison to the base case, the benefits of Site C are larger in the high market (with a projected spot market forecast of about US$43/MWh in F2024), and smaller in the low market scenario (with a projected spot market price of about US$24/MWh in F2024).[34] In the low market sensitivity case, which only has a 20 per cent likelihood, Site C is still more cost competitive than the Clean Generation Portfolio without Site C but is marginally less cost competitive than the Clean + Thermal Generation Portfolio without Site C in the F2024 case. In this latter case, lower natural gas prices favour the thermal alternative with the energy surplus that comes with Site C in its early years now being sold at a lower market price. For the F2026 case, Site C also compares favourably to the alternative portfolios.

Table 6-16 Sensitivity of Site C Benefit to Market Prices

Difference in PV Cost (Portfolio without Site C minus with Site C ($F2013 million)	Project ISD	Market Scenario 3 - high market prices (15% likelihood)	Base Case: Market Scenario 1 – mid market prices (60% likelihood)	Market Scenario 2 – low market prices (20% likelihood)
Clean Generation Portfolio	F2024	830	630	450
	F2026	1,030	880	760
Clean + Thermal Generation Portfolio	F2024	470	150	(90)
	F2026	660	390	220

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

[34] No GHG regulation and natural gas prices at $3/ MMBTU are assumed for the entire forecast period.

6.4.4.4 Site C Capital Cost

As outlined in section 3.2.2 and section 9.2.6, the Site C cost estimate is a Class 3 cost estimate as defined by the Association for the Advancement of Cost Engineering (**AACE**), and includes an appropriate level of contingency to reflect uncertainty in future conditions. The cost estimates for the alternative resources to Site C as presented in Chapter 3 are generally Class 4 with some Class 5.

As per the AACE International Recommended Practice No. 69R-12: Cost Estimate Classification System as Applied in Engineering, Procurement, and Construction for the Hydro Power Industry[35] ("the AACEI Practice"), Class 4 cost estimates are generally based on feasibility studies and are typically used for alternative evaluations. They have a fairly wide range of accuracy, ranging between -15 to -30 per cent on the low side, and +20 to +50 per cent on the high side. Class 5 cost estimates are generally based on concept screening, and also have a wide accuracy range, ranging between -20 to -50 per cent on the low side and +30 to +100 per cent on the high side.

The range of accuracy for a Class 3 estimate is -10 to -20 per cent on the low side, and +10 to +30 per cent on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). As a result, the specific accuracy range applied to a cost estimate is dependent on both the estimating methodology and the characteristics of the project. BC Hydro believes that, given the characteristics of Site C and the state of the project design at the time of estimation, the use of a +10 per cent capital cost sensitivity (with the costs of all other resources held constant) is appropriate for the analysis of Site C compared to the alternatives. This is consistent with the capital cost sensitivities used in generation project CPCN applications with the BCUC.

[35] AACE International Recommended Practice No. 69R-12, page 3 of 14.

The reasons for the use of a +10 per cent capital cost sensitivity in the analysis of alternatives to Site C include:

- **Maturity Level of Project Design:** At the time of the preparation of the project cost estimate, the maturity level of project definition deliverables for major components of Site C was at the high end of the AACE guidelines for a Class 3 estimate.
  - Drawings were complete for all major project components, enabling detailed quantity take-offs and analysis of project logistics. This provided a high degree of resolution in development of the cost estimate.
  - For areas where design assumptions had not been finalized, estimators adopted conservative assumptions reflecting the highest cost impact of potential future design decisions
  - As a result of this high level of definition, the capital cost estimate was prepared using a “bottom-up” deterministic methodology, utilizing individual line items for quantities and unit costs required for project construction
- **Inclusion of Contingency:** Site C cost estimate includes an appropriate level of contingency ($730 million in $2013) that recognizes the remaining uncertainty in project components.
  - BC Hydro reviewed the level of project design and remaining uncertainty for each project component individually, and considered risks within the following categories:
    - Technical Content (level of precision of design and associated quantity take-offs)
    - Precision of Estimate (productivities, equipment selection, material costs and market variations)
    - Schedule (acceleration of activities to maintain overall schedule)

- The contingency for individual project components ranged between 15 and 36 per cent.

- The overall contingency for the direct construction costs was then estimated using a Monte Carlo analysis. The contingency adopted (18 per cent on direct construction costs) was the upper 90^{th} percentile provided by the Monte Carlo analysis as rounded to the nearest 1 per cent.
- Please note that capital cost sensitivity analysis conducted in this IRP are performed compounded on top of project contingency

- **Mature Technology:** Hydroelectric generation facilities are a mature technology with established estimating techniques.
  - A significant portion of Site C's costs are associated with earth moving activities which have limited technical risk
  - The main technical risk to Site C comes from geotechnical risk associated with foundation conditions. Historical site investigations over the past several decades have allowed BC Hydro to develop a project design to minimize these geotechnical risks.
- **Review and Project Controls:** BC Hydro undertook both internal and external reviews of the cost estimate, and is continuing to manage costs to remain within the estimated capital costs.
  - The capital cost estimate was developed by the Site C's Integrated Engineering Team, who has extensive recent experience with hydroelectric project construction
  - The capital cost estimate underwent review by BC Hydro estimators and external construction advisors
  - The capital cost estimate underwent an external peer review by KPMG who concluded that the methodologies and assumptions used in the cost estimate were appropriate

- BC Hydro monitors capital cost drivers on a regular basis, and has established a project management process to maintain project costs within the capital cost estimate.

Given the level of scope definition for Site C, a situation where project capital costs increase by 30 per cent is highly unlikely outside of a scenario where there is a market disruption – i.e., an external, systemic increase to one or more major project cost drivers (such as labour costs or steel prices). Importantly, a change to such a cost driver would not only apply to Site C, but would also affect all other resources options under consideration in the analysis of alternatives. Thus a sensitivity in which Site C's capital costs are increased by 30 per cent and the capital costs of all other alternatives are held constant is not plausible because alternatives would be subject to the same market disruption as Site C. Nevertheless, in response to the feedback from IRP consultation requesting BC Hydro to test additional cost overrun scenarios, BC Hydro has analyzed where Site C's capital costs are increased by 15 per cent and 30 per cent while the cost of all other alternatives remains constant.

To provide analysis of the potential consequences of a market disruption, BC Hydro conducted sensitivity analysis showing the cost-effectiveness of Site C in a scenario where both Site C and alternative resources experience a 30 per cent increase in cost. This 30 per cent sensitivity is at the high end of the range for a Class 3 estimate but much less than the high 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 even higher.

This overall capital cost increase will affect Site C and the resource options differently depending on the proportion of the resource's levelized costs (i.e., UEC and UCC) that comes from capital costs versus operating costs. For example, approximately 90 per cent of Site C's UEC comes from capital costs, and as a result Site C's UEC will be more sensitive to capital cost variations than other resource options with a lower proportion of capital costs. In contrast, alternatives such as natural gas-fired generation are more sensitive to operating cost impacts such as fuel (natural gas) price fluctuations and GHG compliance instrument costs.

Table 6-17 summarizes the portfolio PV results of the capital cost sensitivity analysis. Table 6-18 summarizes the adjusted UEC results of the block analysis for the same capital cost sensitivities.

Table 6-17 Sensitivity of Site C Benefit to Capital Cost Increases

Difference in PV Cost (Portfolio without Site C minus Portfolio with Site C) ($F2013 million)	Clean Generation Portfolios		Clean + Thermal Generation Portfolios	
	F2024	F2026*	F2024	F2026*
Base Case	630	880	150	390
Site C 10% Capital Cost Increase, all other alternatives' costs held constant	360	650	(120)	170
Site C 15% Capital Cost Increase, all other alternatives' costs held constant	250	560	(230)	70
Site C 30% Capital Cost Increase, all other alternatives' costs held constant	(100)	270	(580)	(220)
Site C and Alternative Resource Options 30% Capital Cost Increase	600	950	(60)	300

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

Table 6-18 Sensitivity of Adjusted UEC Analysis to Capital Cost Increase ($/MWh, $2013)

<table>
<tr><th>Adjusted UEC ($2013/MWh)</th><th>Site C (Note 1)</th><th>Clean Generation Block (Revelstoke Unit 6, GMS and Pumped Storage)</th><th>Clean + Thermal Generation Block No. 1 (Revelstoke Unit 6 and 6 SCGTs)</th><th>Clean + Thermal Generation Block No. 2 (Revelstoke Unit 6, GMS and 4 SCGTs)</th></tr>
<tr><td>Base Case</td><td>94</td><td rowspan="4">153</td><td rowspan="4">128</td><td rowspan="4">130</td></tr>
<tr><td>Site C 10% capital cost increase, all other alternative costs held constant</td><td>101</td></tr>
<tr><td>Site C 15% capital cost increase, all other alternative costs held constant</td><td>105</td></tr>
<tr><td>Site C 30% capital cost increase, all other alternative costs held constant</td><td>116</td></tr>
<tr><td>Site C and alternative resource options 30% capital cost increase</td><td>116</td><td>184</td><td>154</td><td>Note 2</td></tr>
</table>

Note 1: The Adjusted UEC for Site C would decrease by about $2/MWh to reflect the seasonal, daily and hourly shaping capability of Site C.

Note 2: The Adjusted UEC for Block #2 will be higher than the adjusted UEC for Block #1 for Site C and Resource Options 30% Capital Cost Increase sensitivity.

As shown in Table 6-17, an increase in Site C's capital costs would result in a decrease in the portfolio PV benefit of Site C over its alternatives:

+10% and +15% Site C Project Capital Costs, Alternative Costs Held Constant: Site C remains cost-effective compared to the Clean portfolio at both ISDs. Compared to the Clean+Thermal portfolio, Site C remains cost-effective at the F2026 ISD but is not cost-effective at the F2024 ISD.

+30% Site C Project Capital Costs, Alternative Costs Held Constant: Compared to the Clean portfolio, Site C remains cost-effective at the F2026 ISD but is not cost-effective at the F2024 ISD. Site C is not cost-effective compared to a Clean+Thermal portfolio at both ISDs. This sensitivity, in which Site C's capital costs are increased by 30% and the capital costs of all other alternatives are held constant, is not plausible because alternatives would be subject to the same market disruption as Site C.

+30% for both Site C Project and Alternative Capital Cost: Site C remains cost-effective compared to the Clean portfolio at both ISDs. Compared to the Clean+Thermal portfolio, Site C remains cost-effective at the F2026 ISD but is not cost-effective at the F2024 ISD.

UEC Block Analysis: The UEC block analysis is shown in Table 6-18. Site C has a lower UEC than the Clean and Clean+Thermal blocks in all capital cost sensitivities. This indicates that Site C has a lower cost than a comparable block of alternative resources providing 5,100 GWh/year and 1,100 MW.

6.4.4.5 Wind Integration Cost

As described in section 3.4.1.4 and section 4.3.4.5, the base assumption for wind integration cost is $10/MWh. For the purpose of testing the sensitivity of the cost competitiveness of Site C, wind integration costs of $5/MWh and $15/MWh were also modelled. The analysis shows that based on an ISD of F2024, the PV benefits of Site C for the Clean Generation portfolio would decrease from $630 million to $530 million for a wind integration cost of $5/MWh, and increase from $630 million to $720 million for a wind integration cost of $15/MWh. Refer to Table 6-19.

Table 6-19 Sensitivity of Site C Benefit to Wind Integration Cost

Portfolio Type	Wind Integration costs	Difference in PV Cost (Portfolio without Site C minus with Site C in F2024) ($2013 million)	Difference in PV Cost (Portfolio without Site C minus with Site C in F2026) ($2013 million)
Clean Generation Portfolio	$5/MWh	530	See Note 1
	$10/MWh	630	880
	$15/MWh	720	See Note 1
Clean + Thermal Generation Portfolio	$5/MWh	90	See Note 1
	$10/MWh	150	390
	$15/MWh	220	See Note 1

Note 1: The benefits for Site C are expected to be higher in portfolios with Site C in-service in F2026.

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

6.4.4.6 Compound Sensitivities

In the IRP analysis presented thus far one variable at a time has been systematically changed to see the impacts of that change on the results. This process allows BC Hydro to determine which variables are the major drivers of cost uncertainty. The results from the preceding sections demonstrate that LRB gap uncertainty is the largest determinant of PV uncertainty. The next largest drivers are market price and Site C capital cost.

Further analysis was conducted to determine the potential compound impacts of these main sources of uncertainty on the cost-effectiveness of Site C. There are two issues that require consideration regarding the joint occurrence of different uncertainty scenarios. Firstly, it is difficult to quantify how individual events fluctuate together. For example, while there is likely a strong correlation between a large gap and high commodity and labour prices (which impact project cost), it is less certain how the large LRB gap/small LRB gap and high market price/low market price scenarios correlate. In the absence of evidence concerning covariance, the starting point for combined sensitivities is to assume that each sensitivity is independent.

Secondly, when combining extreme and uncertain events, the likelihood that these compound events will occur becomes very small compared to the likelihood of the base case unfolding. However, to provide an understanding of extreme outcomes, BC Hydro evaluated the difference in PV costs between portfolios using compound scenarios of the main drivers of uncertainty. Specifically:

- "Compound Low" scenario, with a low-market condition (i.e., Market Scenario 2) and a small LRB gap condition as well as a 10 per cent Site C capital cost overrun
- "Compound High" scenario, with a high-market condition (i.e., Market Scenario 3) and a large LRB gap condition as well as a 10 per cent under-run on the Site C capital cost

These scenarios represent the far ends of the potential probability distribution and are highly unlikely. For example, BC Hydro assessed the probability of the small gap scenario at about 10 per cent, and the low market scenario (Market Scenario 2) at a 20 per cent likelihood. If these two scenarios are treated as independent, the relative likelihood would be about 2 per cent.

The Compound Low scenario has the highest level of financial regret for the decision to build Site C, while the Compound High scenario has the highest level of financial regret for a decision not to build Site C (and to build the Clean or Clean + Thermal portfolios instead).

The Compound Low scenario contains the small LRB gap condition which has a low likelihood. It 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).

Table 6-20 below summarizes the results of the compound sensitivity analysis.

Table 6-20 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) ($2013 million)	Clean Generation Portfolios		Clean + Thermal Generation 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

Note 1: The difference in PV cost in this scenario is expected to be higher than the difference in PV cost in the Clean + Thermal Generation Portfolios for the same sensitivity.

Note 2: The difference in PV cost in this scenario is expected to be higher than the difference in PV cost in the Clean + Thermal Generation Portfolio with a F2024 in-service date for Site C.

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

As shown in Table 6-20, the results of the compound sensitivity analysis are consistent with the results of the large and small LRB gap sensitivity analysis in section 6.4.4.1. Due to the compound effects of market price conditions and capital cost variation, the Compound Low scenario has lower portfolio PV benefits for the Site C project compared to the small gap scenario (-$2,000 million vs. -$1,280 million). Likewise, the Compound High scenario has higher portfolio PV benefits for the Site C project compared to the large gap scenario (+$2,610 million vs. +$2,260 million).

6.4.4.7 Sensitivity Analysis Summary

The sensitivity analysis examined the cost-effectiveness of Site C in a number of sensitivity cases: 1) large gap (i.e., high-load growth with low DSM savings level) and small gap (i.e., low-load growth with low DSM savings level); 2) a smaller cost of capital differential between BC Hydro projects (such as Site C, Revelstoke Unit 6, GMS Units 1-5 Capacity Increase) and IPP projects; 3) high and low market price scenarios; 4) higher capital cost scenarios for Site C and higher capital cost scenario for both Site C and resource alternatives; and 5) high and low wind integration costs. In addition, low probability compound sensitivities reflecting the combined impacts of variability in the major drivers of Site C cost-effectiveness (i.e., LRB gap, market prices and Site C capital cost) were tested.

Table 6-21 presents a summary of the sensitivity analysis. This analysis shows that Site C provides benefits compared to alternatives not only in the base case, but also in a wide range of potential sensitivities. In general, Site C has a PV advantage over viable alternative Clean Generation portfolios except in the scenario associated with long-term low-load growth, and in the implausible scenario of a 30 per cent capital cost increase for Site C while the cost of alternatives held constant. When compared to the Clean + Thermal Generation portfolio, Site C has a cost disadvantage in the scenarios that are generally low probability associated with long-term low-load growth, low market prices and higher Site C capital costs.

Table 6-21 Summary of Sensitivity Analysis of Site C Benefits

Difference in PV Cost (Portfolio without Site C minus with Site C) ($2013 million)	Clean Generation Portfolios		Clean + Thermal Generation 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)	(710)	(1,280)	(910)
With Expected LNG	1,850	Note 1	1,260	Note 1
High Market Price (Scenario 3)	830	1,030	470	660
Low Market Price (Scenario 2)	450	760	(90)	220
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	(100)	270	(580)	(220)
Site C and Alternative Resource Options Capital Cost +30%	600	950	(60)	300
WACC Differential = 1%	420	670	20	230
Wind Integration Cost ($15/MWh)	720	Note 1	220	Note 1
Wind Integration Cost ($5/MWh)	530	Note 1	90	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 1: The benefit for Site C in this scenario is expected to be higher than the comparative portfolio for the same sensitivity.

* Portfolio PV modelling using a F2026 Site C ISD does not capture costs of deferral.

It is possible to construct additional sensitivity scenarios to those presented above. However, these scenarios would likely fall within the extreme bounds described in the compound sensitivity scenarios and would reach the same conclusion: 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, Site C is the preferred resource option to meet BC Hydro’s forecast customer demand.

6.4.5 Other Technical Benefits

Both the Clean Generation and Clean + Thermal Generation portfolios rely significantly on intermittent clean or renewable resources for the energy contribution. Many clean or renewable energy resources – such as wind or run-of-river hydro – are intermittent as their generation varies with natural factors, such as wind speeds or river flows. As a result, intermittent resources cannot be economically dispatched in response to changes in market prices. To integrate these clean or renewable resources into the BC Hydro system and meet electricity demand, these resources must be backed up by dispatchable capacity. As described in the following sub-sections and section 6.9, the ability for the existing BC Hydro system to shape, firm and integrate such resources is limited.

6.4.5.1 Dispatchability

Site C provides dispatchable[36] capacity, which means that Site C can be dispatched to meet the load and generate power when market prices are high and curtail generation when market prices are low. As a dispatchable resource, Site C supplies ancillary benefits to the electric system, including shaping and firming capability to integrate clean or renewable intermittent resources. The value of shaping within a month is reflected in the System Optimizer modelling, but the benefits of firming and inter-month shaping are not captured.

6.4.5.2 Wind Integration Limit

A preliminary analysis was completed to determine the maximum amount of wind power that can be integrated into the current BC Hydro power system without impacting the reliability and security of the system. The analysis is based on the assumption that only dispatchable generation from automatic generation control (**AGC**) plants can be used to manage wind variability and ramps.

[36] A resource whose output can be adjusted to meet various conditions including fluctuating customer demand, outages, market price changes and non-power related considerations.

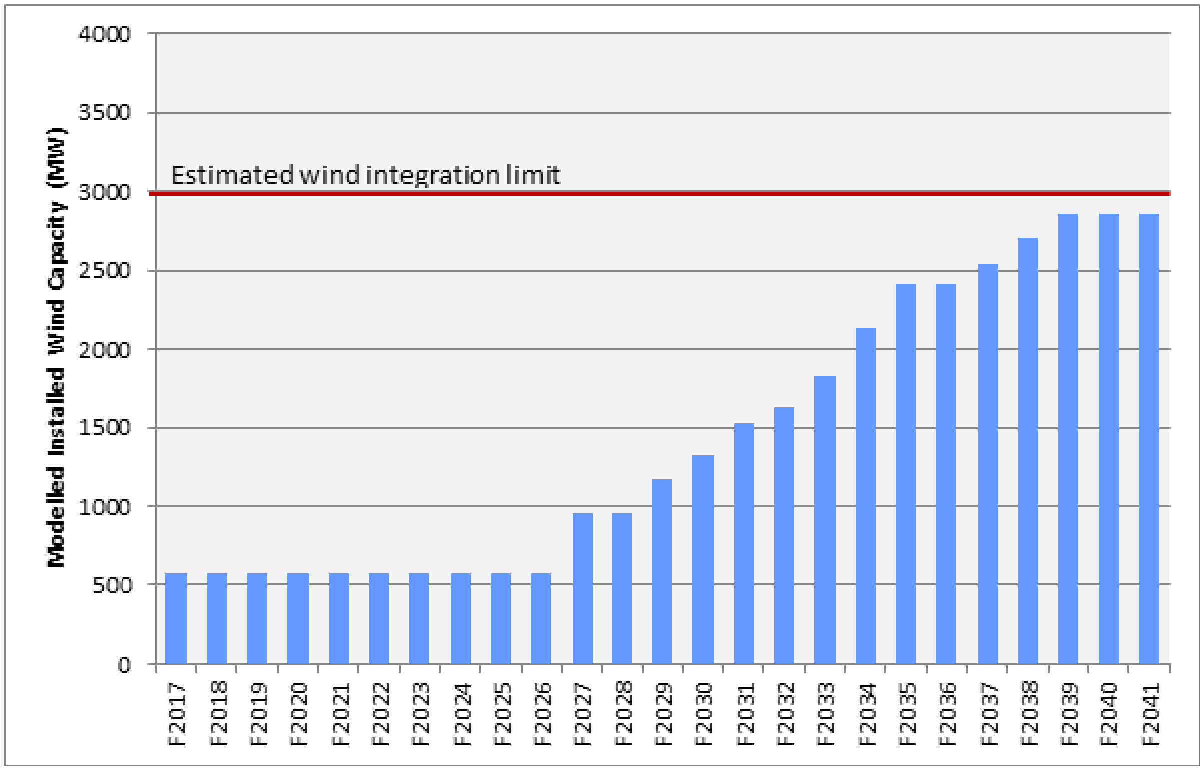
The analysis is based on actual hourly system operation data, including load, generation, maximum/minimum generation limits, outages and tie line schedules, for the period October 2007 to September 2008. Actual wind data is not used in this analysis, but instead it is assumed that intra-hour wind power fluctuations may range from minimum to maximum output (worst case scenario) and that dispatchable resources have to be able to respond to these fluctuations.

The analysis shows that the system is most constrained during the freshet period, when the available dispatchable AGC generation drops to approximately 3,000 MW. Therefore 3,000 MW has been adopted as the current wind integration limit. This preliminary analysis does not consider transmission constraints, market constraints for the surplus wind energy, or trade-offs with spilling and/or wind curtailment. Since the analysis is based on historical data, it also does not include a build-out of the BC Hydro system, which would include Mica Units 5 and 6 and Revelstoke Unit 5, and if approvals are obtained would also include Site C. BC Hydro will continue to refine the understanding of its wind integration limit and explore resources and methods (e.g., spilling/curtailment) that can enhance integration capability.

If Site C were not built, alternative resources, consisting mostly of wind power, would gradually exhaust the remaining integration capability of the system and additional integration capability would be required. Figure 6-9 shows the increase in modelled installed capacity over time, from wind resources for the Clean Generation portfolio with a mid gap, no LNG scenario and no Site C. The increase in installed wind capacity would be advanced if the gap were larger. The estimated wind integration limit shown in the figure has the limitations as described in the previous paragraph and does not reflect any increase in integration capability that may come with the addition of pumped storage units to the portfolio.

A separate preliminary analysis shows that the addition of Site C could increase the wind integration 3,000 MW limit by up to 900 MW. However, the overall effects on the wind integration limit given the recent and future planned capacity additions as well as the potential addition of LNG load have not been concluded.

Figure 6-9 Modelled Installed Wind Capacity under the Clean Generation Portfolio (Mid Gap, without LNG and without Site C)



6.4.6 Environmental Attributes

Portfolios with and without Site C were compared based on their environmental attributes. Table 6-22 lists the environmental attributes for the Site C, the Clean Generation and both Clean + Thermal Generation portfolios used in the unit cost comparison presented in section 6.4.2.

The advanced level of project definition for Site C allows a high level of accuracy in determining its footprint. In contrast, portfolios without Site C are populated with "typical" projects using representative footprints. As a result, the environmental attributes presented in this section compare defined attributes of Site C to representative estimates of clean or renewable IPPs. The actual difference in attributes between portfolios cannot be known with certainty. The portfolio values include the impacts of associated transmission requirements to the POI.

Table 6-22 Environmental Attributes for the Site C, Clean Generation and Clean + Thermal Generation Portfolios

Category	Indicator	Units	Classification	Clean Portfolio	Clean + Thermal (6 SCGT)	Clean + Thermal (4 SCGT)	Site C Portfolio
Land	Footprint	hectares	n/a	2,555	1,768	2,067	5,661
Freshwater	Affected Stream Length	kilometers	n/a	–	–	–	123
	Reservoir Aquatic Area	ha	n/a	–	–	–	9,310
Atmosphere	GHG emissions	tonnes/year, thousands	Carbon dioxide equivalent	217	657	511	–
	Air Contaminant Emissions	tonnes/year, thousands	Oxides of nitrogen	0.3	0.6	0.5	–
			Carbon monoxide	0.0	1.3	0.9	–

Land and freshwater footprint: Table 6-22 shows that all four portfolios have land footprints, although Site C has a larger land footprint than portfolios without the project. Since the Clean Generation and the Clean +Thermal Generation portfolios contain a high percentage of onshore wind generation, the Site C portfolio also has a larger freshwater footprint than the portfolios that do not include Site C.

The land and freshwater footprint of Site C reservoir represents a conversion of habitat from terrestrial and river environments to a reservoir environment, and not a loss of productive environment. This may not be the case with other portfolios based on alternative resources. As a result, portfolios with Site C include the creation of a 9,310 ha reservoir, while portfolios without Site C do not. It should be noted that pumped storage, an alternative capacity rich option and net energy consumer, is assumed to occur on existing water bodies with no reservoir footprints. This is likely a conservative assumption as no pumped storage project has been permitted in B.C. to date.

The differences in land and freshwater footprint are highly dependent on the mix of energy resources. The portfolios generally include a majority of wind energy. If these portfolios had a higher proportion of run-of-river resources (as was the result of BC Hydro's recent calls for power), it is likely that the portfolios of alternatives would have a comparable or larger footprint than the Site C portfolio as wind and biomass resources generally have smaller footprints per unit energy delivered than either Site C or run-of-river hydro. It is also important to note that the land footprints in Table 6-22 consist of the footprints for the primary generation site, transmission and road to the POI. For hydroelectric projects such as Site C and run-of-river resources, this footprint includes the fuel collection footprint (i.e., the water). For other available resource options such as natural gas-fired generation or biomass, the fuel collection footprint is not included in the land footprint.

GHG Emissions: The GHG emissions shown in Table 6-22 represent planning-level estimates of GHG emissions during the operating phases of the projects. The Site C portfolio has lower operational GHG emissions than the portfolios not including Site C. The Clean Generation portfolio selects a municipal solid waste (**MSW**) resource option, which includes GHG emissions from fuel combustion. The Clean + Thermal Generation portfolio has the highest level of GHG emissions due to the combustion of natural gas.

BC Hydro has developed an estimate of GHG emissions associated with Site C for the Site C Environmental Impact Statement (EIS) (refer to the Site C EIS, Volume 2 Appendix S Greenhouse Gases Technical Report). GHG emissions were modelled using the Intergovernmental Panel on Climate Change guidelines. This was an assessment of the life-cycle GHG emissions from Site C and alternatives, rather than the operating phase analysis conducted in the IRP.

The modelled emissions for Site C were then compared to those of other alternative generation options to determine if there are GHG reduction benefits to the selection of Site C over other alternatives. To perform this comparison, BC Hydro used the GHG emissions per unit energy generated by Site C and by alternative generation options. This provides a relative comparison of the GHG emissions that would result in replacing the 5,100 GWh produced by Site C with 5,100 GWh of energy produced by other sources.

As shown in Table 6-23 (extracted from Table 7.14 of the Site C Environmental Impact Statement as amended), results from GHG modeling found that, when compared to other forms of electricity generation, Site C would produce among the lowest GHG emissions per unit of energy produced. Over the next 100 years, Site C would produce the same or lower GHG emissions than all other options available in B.C. for the 5,100 GWh of annual energy generation from Site C.

Table 6-23 CO_2e for Different Resource Types

Generating Facility Type	Range (g CO_2e/kWh)	Average (g CO_2e/kWh)
Site C Clean Energy Project *	N/A	10.5
Canada Boreal Hydroelectric	8 – 60	36
Tropical Hydroelectric	1,750 – 2,700	2,150
Model Coal	959 – 1,042	1,000
Integrated Gasification Combined Cycle	763 – 833	798
Diesel	555 – 880	717
Natural Gas Combined Cycle	469 – 622	545
Solar Photovoltaic	13 – 104	58
Wind Turbines	7 – 22	14

* Reported project emission intensities are based on IPCC – Tier 3. Values are from Site C EIS Volume 2 Appendix S Greenhouse Gases Technical Report.

Local Air Emissions: Table 6-22 shows that the Site C portfolio has lower local air emissions than the portfolios not including Site C. The Clean Generation portfolio selects both wood-based biomass and MSW resource options, which create local air emissions from fuel combustion. The Clean + Thermal Generation portfolio includes biomass resources as well as natural gas-fired generation and, thus has the highest level of local air emissions.

Location of Portfolio Footprint: The locations of the environmental attributes used in the analysis of alternatives were compared between portfolios. Site C is located solely in the Peace Region, whereas the alternative resources are located in a variety of locations across the province. However, as shown in Table 6-7, Table 6-8 and Table 6-9, the portfolio analysis identifies wind as the primary source of energy for the system, with more than 90 per cent of wind resources located in the Peace Region. As a result, more than 50 per cent of the land footprint in both the Clean Generation and the Clean + Thermal Generation portfolios are located in the Peace Region, with the balance in the Lower Mainland and on Vancouver Island.

6.4.7 Economic Development Attributes

Portfolios with and without Site C were compared based on their economic development attributes, including jobs and GDP. Table 6-24 lists the economic development attributes for Site C and for the Clean Generation and Clean + Thermal Generation portfolios, based on a Site C equivalent 5,100 GWh/year (1,100 MW) block of power. The portfolio values include the impacts of associated transmission requirements to the POI.

Table 6-24 Economic Development Attributes for the Site C, Clean Generation and Clean + Thermal Generation Portfolios

Indicator	Units	Classification	Clean Portfolio	Clean + Thermal (6 SCGT)	Clean + Thermal (4 SCGT)	Site C Portfolio
Construction period GDP	$ millions	Total	2,513	1,616	1,706	3,676
Construction period employment	jobs	Total	30,788	19,872	20,963	44,249
Operations period employment	jobs per year	Total	998	985	958	74

The Site C portfolio shows higher measures of economic development during construction as compared to portfolios without Site C. Jobs and GDP related to construction are higher for the Site C portfolio, due to the high job intensity during the construction period. Jobs and GDP during operations are lower for the Site C portfolio as a result of the low operating costs for Site C. It should be noted that these are high-level estimates and the exact differences between economic development attributes are uncertain.

6.4.8 Conclusions

The IRP analysis demonstrates that, even in a no LNG load scenario, portfolios with Site C are more cost competitive than portfolios without Site C regardless of whether the 7 per cent natural gas-fired generation headroom is used. Based on these results, it is prudent to continue with the current regulatory window and maintain Site C's earliest ISD of F2024, given that it is cost-effective at its earliest ISD, and there is a need for capacity prior to and a need for energy shortly after the earliest ISD.

A number of sensitivity cases were examined with a no LNG scenario. These include: 1) large gap (i.e., high-load growth with low DSM savings level) and small gap (low-load growth with low DSM savings level); 2) a smaller cost of capital differential between BC Hydro projects (such as Site C, Revelstoke Unit 6, GMS Units 1-5 Capacity Increase) and IPP projects; 3) high and low market price scenarios; 4) higher capital costs scenarios for Site C and higher capital cost scenarios for both Site C and resource alternatives; and 5) high and low wind integration costs. In addition, low probability compound sensitivities reflecting the combined impacts of variability in the major drivers of Site C cost-effectiveness (LRB gap, market prices and Site C capital cost) were tested. The analysis showed that Site C provides benefits compared to alternatives not only in the base case, but also for a range of potential sensitivities.

In addition to providing energy and capacity, Site C also provides ancillary shaping and firming benefits and capability to integrate intermittent resources. Although the analysis generally shows a greater environmental footprint for the Site C portfolio than for the alternative portfolios, the ancillary and economic development benefits associated with Site C continue to support the recommendation to pursue this project. Site C also aligns with the *CEA* 93 per cent clean or renewable energy target and legislated *GGRTA* GHG reduction targets. As a result, BC Hydro believes that Site C provides the best combination of financial, technical, environmental and economic development attributes.

The development of Site C is subject to environmental assessment certification; fulfilling the Crown's duty to consult and, if appropriate, accommodate First Nations which may be potentially affected by Site C; and B.C. Government approval to proceed to full project construction.

Conclusions in this Site C section supports Recommended Action 6 as described in section 9.2.6.

6.5 LNG and the North Coast

6.5.1 Introduction

The key IRP question for BC Hydro regarding LNG and the North Coast is - What actions are needed and what supply options need to be maintained to ensure that BC Hydro is able to supply Expected LNG, additional LNG load above expected and other loads in the North Coast while considering the specific planning challenges of this region? This section focuses on the incremental generation and transmission resources needed to serve LNG load given the context of maintaining the current DSM target and advancing Site C for earliest ISD.

As described in Chapter 2, the Expected LNG electrification load is 3,000 GWh/year (360 MW) based on discussions with the B.C. Government and LNG proponents. However, this level of load is uncertain so a range of 800 GWh/year (100 MW) to

6,600 GWh/year (800 MW) is considered. The majority of the LNG loads are expected to be located on the North Coast and several projects could be online as early as F2020. In addition, there is potential for other non-LNG loads, primarily in the mining sector, that could also increase load in the region.

The North Coast region in northwestern B.C. is connected to the rest of the BC Hydro system via a 450 km single radial 500 kV transmission line from Prince George to Terrace. Beyond Terrace, the area is served by two 287 kV transmission lines - one that extends to Kitimat and another that extends to Prince Rupert. When the 287 kV NTL project is completed in May 2014, service will be extended north to Bob Quinn and will interconnect the Forrest Kerr, McLymont, and Volcano hydroelectric projects, and several potential mines.

The North Coast region poses unique planning challenges for BC Hydro due to its remote location, large range of load potential and limited local clean or renewable capacity resources. Although the existing 500 kV transmission supply has maintained a high level of reliability, increasing loads will require a trade-off between adding local natural gas-fired generation versus the ability to reinforce the existing transmission system to the main grid. These challenges require a flexible supply strategy that can meet the range of increasing load levels in a timely and cost-effective manner.

6.5.2 Additional Resource Requirement to Serve LNG and Other Loads

Supply requirements are initially assessed by reviewing the LRBs with various LNG load levels (see Figure 6-10 and Figure 6-11). For the 3,000 GWh/year Expected LNG level, there is a short-term firm energy gap before Site C's earliest ISD of about 1,100 GWh/year, and a short-term capacity gap before Site C's earliest ISD of up to 650 MW. The higher amounts of LNG loads considered (up to 6,600 GWh/year (800 MW)) would increase energy requirements before Site C's earliest ISD to 4,700 GWh/year and the need for dependable capacity resources to 1,100 MW.

Figure 6-10 System Energy Surplus/Deficit after BRP Implementation under Different LNG Load Scenarios

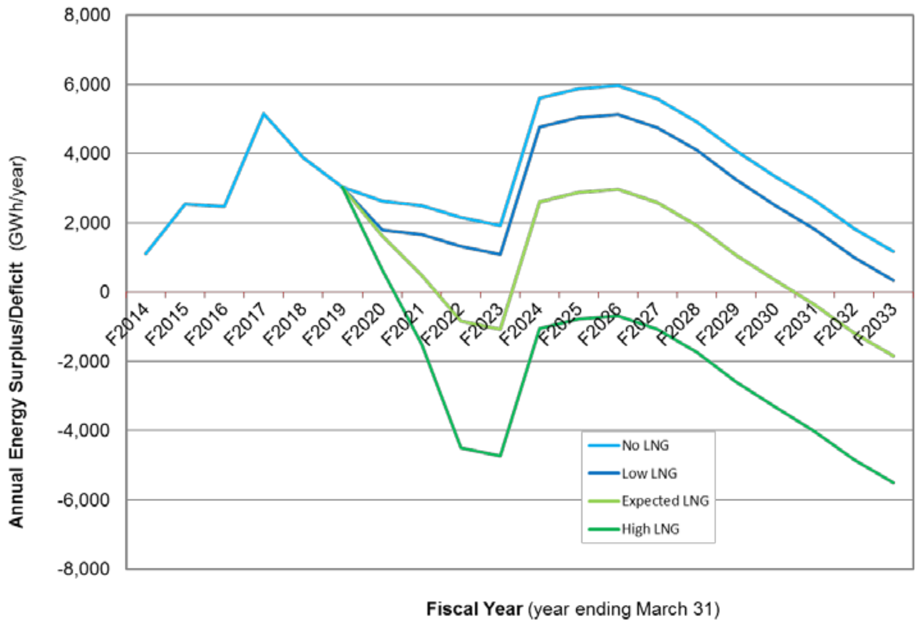
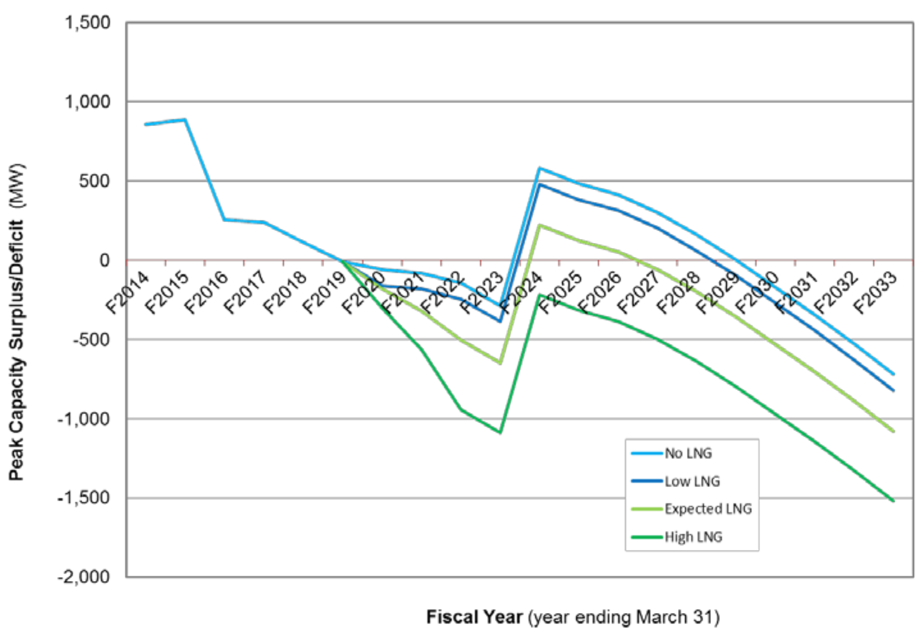


Figure 6-11 System Capacity Surplus/Deficit after BRP Implementation under Different LNG Load Scenarios



In addition to system energy and capacity needs, there would also be requirements to increase the capacity of the transmission tie between the North Coast and the integrated system, or alternatively develop dependable generation capacity locally in the North Coast. As described in section 2.5.1 and shown in Figure 2.10, the N-0, non-firm transfer capability of the existing radial transmission system could be exceeded under a number of LNG and mining load scenarios.

6.5.3 North Coast Transmission Planning Considerations

Managing the maintenance outages on the cascading 5L61, 5L62, and 5L63 circuits that span from Prince George to Terrace is critical to maintaining reliable supply to the North Coast. The maintenance outages using standard methods can last six to seven days and are currently accomplished without interrupting the supply by: scheduling the outages in the spring when customer loads are generally low; coordinating with planned outages at industrial facilities; and utilizing local generation facilities (including Prince Rupert and Falls River generating stations) and relying upon contracted delivery from Rio Tinto Alcan's Kemano facility. The local LRB is tight even during spring load conditions, leaving little margin to continue the outage management process with additional loads being added to the area.

Options to accommodate line maintenance outages with future LNG loads and increased mining activity include reduction of outage duration, additional coordination of outages with customers including LNG facilities, capital spending at existing BC Hydro facilities in the North Coast to ensure reliability, and the development of new local dependable capacity in the form of natural gas-fired generation. Run-of-river IPP facilities scheduled to come online within the next few years would also facilitate maintenance outages, especially if carried out during the freshet season.

The radial transmission system is also prone to system disturbances such as line to ground faults, the sudden loss of a large load due to an outage at an industrial customer facility, or the loss of generation due to a forced outage of a local generator or the interconnecting transmission line. In these cases, injection of instantaneous reactive power is often required to maintain acceptable voltages and system stability. Reactive power support can be delivered by power electronics controlled devices or local generators. The reactive power contribution of the local generators is maximized when the units are operated in the synchronous condenser mode.

The LNG loads would likely be in the Kitimat or the Prince Rupert sub-regions of the North Coast. The 287 kV transmission line 2L99 interconnects Minette Substation (**MIN**) at Kitimat to Skeena at Terrace which is the terminus of the 500 kV line from the integrated system. 2L99 is near end-of-life and would likely require upgrades or replacement regardless of LNG loads at Kitimat. Other regional upgrades, such as providing voltage support at MIN, may also be needed. Similarly, some upgrades may be required on the 287 kV circuit 2L101 that interconnects Prince Rupert to Skeena. Regional transmission requirements have not been analyzed in the IRP and will be studied as part of LNG load interconnection studies. Consideration may be given to strategically siting natural gas-fired generation in these sub-regions of the North Coast in order to avoid or defer transmission upgrades, to enhance the reliability of supply, and to support the regional transmission system.

6.5.4 Supply Options

The options available to supply future load growth in the North Coast are:

(a) Integrated System Supply: Strengthen the transmission connection between the North Coast and the rest of the integrated system to facilitate the transfer of capacity necessary to meet future load growth. Generation resources can be developed anywhere within the integrated system with this supply option.

(b) Local Supply: Develop capacity resources locally in the North Coast

(c) A combination of (a) and (b): Carrying out some cost-effective transmission upgrades along with the development of local capacity resources

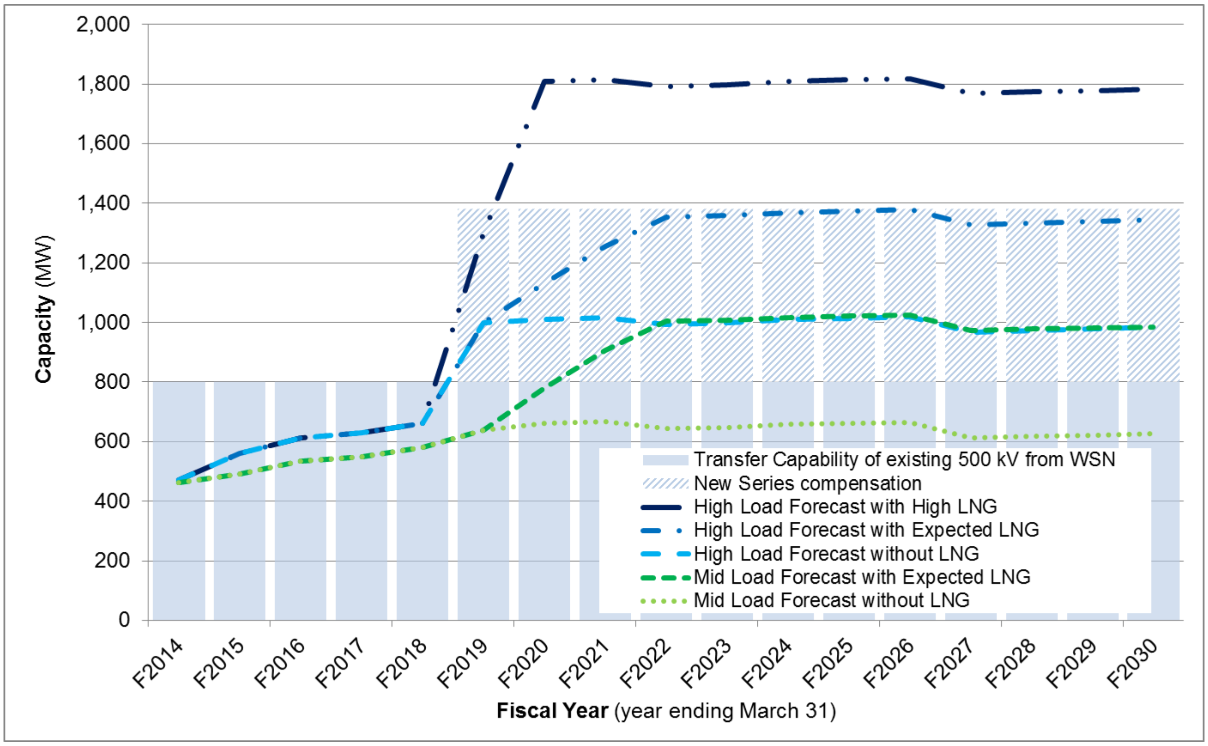
Options (a) and (b) are discussed below while the results of portfolio analysis used to determine the cost-effectiveness of the options are presented in section 6.5.5.

Integrated System Supply

An integrated system supply solution requires the transmission system to be capable of transferring adequate capacity to meet future North Coast loads. Figure 6-12 compares the transfer capability of the existing 500 kV transmission line from Prince George to Terrace against potential North Coast load combinations. It shows that the capacity of the existing line would provide adequate capacity only in a mid-load forecast without any LNG. Any other combination of loads where LNG loads are as expected or where mining loads are higher than expected would result in the capability of the transmission line being exceeded. Most of the load scenarios considered can be accommodated by non-wire upgrades to the existing transmission line to increase its capacity. Non-wire upgrades consisting of adding series and shunt compensation and transformation capacity would cost approximately $150 million. The upgrades would increase the total transfer capability to around 1,380 MW and would take three to four years to complete. A second line from Prince George is required only in a scenario where high mining load is combined with a high LNG load. A second 500 kV line would have a cost more than $1.1 billion[37] and have a lead time of eight to 10 years.

[37] All cost values presented (UECs, UCCs, capital costs) are expressed in $F2013.

Figure 6-12 North Coast Load Scenarios and the Capability of the Transmission Connection to the Integrated System



Transmission capacity additions allow the generation resources required to serve LNG and other North Coast loads to be located anywhere within the integrated system. This flexibility to locate resources would allow BC Hydro to develop the most cost-effective resources, including capacity options such as Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and natural gas-fired generation, to meet need. It also facilitates the use of bridging resources and non-firm/market energy to bridge short-term capacity and energy requirements. In general, bridging capacity and additional non-firm/market energy reliance that are utilized only during years of need is the lowest cost option as opposed to building new resources that could add to a surplus position when another large resource such as Site C is developed in subsequent years.

Local Supply

An alternative to system supply is to build dependable capacity locally in the North Coast. The dependable capacity options available in the North Coast are limited. Pumped storage hydro resource potential in the region is not cost-effective, as identified in the study described in Appendix 3A-30. As shown in section 3.4, biomass potential in the region is limited, leaving natural gas-fired generation as the only available cost-effective option. The British Columbia Energy Objectives Regulation described in section 1.2.4 exempting natural gas-fired generation used to serve LNG export facilities from the *CEA* 93 per cent clean or renewal objective enables BC Hydro to serve LNG load with a greater proportion of natural gas-fired generation, which also has a relatively short construction lead time once permitting is secured. The addition of natural gas-fired generation in the North Coast would provide the following benefits:

1. Support North Coast transmission capability and reliability and address the issues identified in section 6.5.3
2. Meet broader system needs for dependable generation capacity
3. Provide dispatchable dependable capacity to integrate renewable energy resources in the region
4. Provide the ability to dispatch off in favour of system surplus and low-cost market resource usage at times of the year when there is sufficient transmission access

Natural gas-fired generation can be developed in the North Coast to provide dependable generation capacity:

- with clean or renewable energy resources sourced locally or from the integrated system

- with natural gas-fired units being relied upon for firm energy and operated as base-loaded units or
- with natural gas-fired units being relied upon for firm energy but mostly dispatched off in favour of lower cost surplus or non-firm energy from the integrated system or market imports

6.5.5 Evaluation of North Coast Supply Options

Portfolio analysis was carried out using the 3,000 GWh/year Expected LNG load and the 6,600 GWh/year high LNG load to identify the cost-effectiveness of the various supply alternatives given the context of maintaining the current DSM target and advancing Site C for earliest ISD.

An initial set of portfolios was evaluated to identify the optimal approach towards meeting LNG and other North Coast loads in the period prior to in-service of Site C. As described previously, the 3,000 GWh/year Expected LNG level will create a short-term capacity gap before Site C of up to 650 MW and an energy shortfall of about 1,100 GWh/year. Several options were evaluated: 1) Integrated system supply with short-term energy and capacity needs bridged until Site C's ISD; 2) Integrated system supply with short-term energy needs bridged until Site C's ISD and with Revelstoke Unit 6 built to meet capacity needs; 3) Dependable capacity in the form of natural gas-fired generation developed locally with short-term energy needs bridged until Site C's ISD; and 4) Dependable capacity in the form of natural gas-fired generation developed locally along with renewable energy resources built to meet energy deficit prior to Site C's ISD.

Table 6-25 summarizes the portfolio PV of the cost savings, and shows that both energy and capacity bridging yields significant savings. In planning to average water conditions at its Heritage hydroelectric facilities, BC Hydro could encounter a market exposure of about 4,100 GWh/year should critical water conditions occur. BC Hydro contemplated the pros and cons of additional non-firm/market reliance by looking at the effects of water variability, market conditions, market access, operational constraints and additional planning uncertainties. It concluded that the aforementioned energy gap of approximately 1,100 GWh/year in an Expected LNG load scenario could be filled using additional non-firm/market reliance and would still result in a highly reliable system if the reliance was limited to the short time frame leading up to the ISD of Site C. However, BC Hydro is of the view that relying on the electricity markets for capacity poses a greater reliability risk in comparison to energy reliance. The reliability risks of additional capacity reliance over and above the market reliance contemplated in a no LNG scenario as described in section 6.9.3.1 need to be weighed against the potential cost savings. Therefore, a supply strategy between options 1) and 3) described in the preceding paragraph seems most prudent allowing BC Hydro to take advantage of the cost savings offered by bridging using non-firm/market energy while developing some dependable capacity to ensure reliability. Non-wire upgrades of the existing 500 kV line to the North Coast and advancing natural gas-fired capacity in the North Coast are required to facilitate this intermediate strategy. Approximately four 100 MW SCGTs to match the incremental capacity requirement of 360 MW from Expected LNG may be required as part of this strategy.

Table 6-25 Comparison of Alternative Supply Options to meet needs prior to Site C in-service

Supply Options	Integrated system supply with short-term energy and capacity needs bridged until Site C ISD	Integrated system supply with short-term energy needs bridged until Site C ISD and with Revelstoke Unit 6 built to meet capacity needs	Dependable capacity in the form of natural gas-fired generation developed locally with short-term energy needs bridged until Site C ISD	Dependable capacity in the form of natural gas-fired generation developed locally along with renewable energy resources built to meet energy deficit prior to Site C ISD
Incremental Energy Resource for LNG before Site C	Bridging	Bridging	Bridging	Build B.C. Clean Resources
Incremental Capacity Resource for LNG before Site C	Bridging	Build Revelstoke Unit 6	Build four 100 MW SCGTs to match LNG capacity requirement	Build four 100 MW SCGTs to match LNG capacity requirement
Series Compensation of WSN-SKA transmission Line	Required	Required	Not required	Not required
Portfolio PV cost relative to Reference Portfolio* ($ million)	(490)	(120)	(280)	Reference Portfolio

*In all of these portfolios, clean or renewable energy resources backed by SCGTs in the North Coast for capacity are assumed to be built for need subsequent to Site C.

BC Hydro also carried out analysis to determine the longer-term supply strategy to supply LNG, subsequent to Site C earliest ISD. The high LNG load was used to identify the relative costs of the various supply alternatives. This analysis assumed a reliance on non-firm/market energy of 1,100 GWh/year prior to Site C ISD, the implementation of the non-wire upgrades of the existing 500 kV line, and development of natural gas-fired generation in the North Coast given the benefits of pursuing those actions as demonstrated in the previous analysis.

The higher level of LNG load considered would result in 3,600 GWh/year of additional energy resources being required as well as 400 MW of additional capacity over and above the requirements for Expected LNG. The supply options considered for this analysis were: (i) Integrated system supply facilitated by the addition of a second 500 kV line; (ii) Local natural gas-fired capacity with renewable energy resources sourced locally or from the integrated system; (iii) Local natural gas-fired capacity with units being relied upon for firm energy and operated as base-loaded units; and (iv) Local natural gas-fired capacity with the units being relied upon for firm energy but mostly dispatched off in favour of lower cost surplus or non-firm energy from the integrated system or market imports. Table 6-26 summarizes the key characteristics and trade-off parameters of these options.

Development of local natural gas-fired generation that is relied upon for firm energy and dependable capacity and dispatching the units economically provides the most cost-effective supply for meeting the LNG loads. Natural gas-fired generation can be dispatched off during times when non-firm energy is available and/or market electricity prices are low such as during the freshet or light load hours of other months. This option avoids the footprint of new transmission lines and associated clean or renewable resources across BC Hydro’s service area. However, market imports used to displace natural gas-fired generation may attract GHG liability in the future. The potential cost of such liability is not reflected in the analysis.

Table 6-26 Comparison of Alternative Options to meet Long-Term System Needs due to High LNG

Supply Options	**(i) Integrated system supply facilitated by the addition of a second 500 kV line**	**(ii) Local natural gas-fired capacity with renewable energy resources sourced locally or from the integrated system**	**(iii) Local natural gas-fired capacity with units being relied upon for firm energy and operated as base-loaded units**	**(iv) Local natural gas-fired capacity with the units being relied upon for firm energy but mostly dispatched off in favour of lower cost surplus or non-firm energy from the integrated system or market imports**
Incremental Energy Resource for LNG	Renewable energy resources distributed across the integrated system	Renewable energy resources distributed across the integrated system	Generation from natural gas-fired units located in the North Coast	Combination of natural gas-fired generation, non-firm energy from the integrated system and market energy
Transmission Requirements over and above non-wire upgrades of existing transmission line	Second 500 kV line from Prince George to Terrace	None	None	None
Incremental Capacity Resource for LNG	Capacity resources distributed across the integrated system	Natural gas-fired capacity in the North Coast	Natural gas fired capacity in the North Coast	Natural gas fired capacity in the North Coast
Reliability and Maintenance Flexibility	Provides N-1 service to the region as well as comparatively highest degree of maintenance flexibility	High level of reliability and maintenance flexibility	Higher level of reliability and same level of maintenance flexibility in comparison to (ii) or (iv)	High level of reliability and maintenance flexibility
Portfolio PV ($M) cost relative to Reference Portfolio	Reference Portfolio	(710)	(2100)	(2900)

Supply Options	(i) Integrated system supply facilitated by the addition of a second 500 kV line	(ii) Local natural gas-fired capacity with renewable energy resources sourced locally or from the integrated system	(iii) Local natural gas-fired capacity with units being relied upon for firm energy and operated as base-loaded units	(iv) Local natural gas-fired capacity with the units being relied upon for firm energy but mostly dispatched off in favour of lower cost surplus or non-firm energy from the integrated system or market imports
GHG emissions ('000 tonnes in F2041) relative to Reference Portfolio	Reference Portfolio	0	700	0
Total Water and Land Footprint (ha in F2041) relative to Reference Portfolio	Reference Portfolio	(2,700)	(5,500)	(7,400)

6.5.6 Conclusions

Given the current DSM target, expected EPA renewals and Site C being advanced for its earliest ISD, the most cost-effective option for BC Hydro to supply the Expected LNG load of 3,000 GWh/year before Site C is with energy delivered from the integrated system, including market energy reliance. Non-wire upgrades of the existing 500 kV line facilitate system delivery of energy and capacity and allow BC Hydro to derive benefits of bridging short-term needs to serve expected LNG. Therefore, it is prudent to advance the non-wire Prince George to Terrace Capacity (**PGTC**) upgrade project to maintain an in-service date of F2020. BC Hydro should also consider natural gas-fired generation in the North Coast for meeting incremental capacity need from Expected LNG given the need to limit reliance on market capacity and the benefits that natural gas-fired generation offers in facilitating maintenance outages and increasing voltage stability. As described in section 9.3.1, BC Hydro recommends advancing work to determine where and how natural gas-fired generation could be built in the North Coast to reduce project lead times and to be able to meet LNG load requirements.

The higher level of LNG load considered would result in 3,600 GWh/year of additional energy resources being required as well as 400 MW of additional capacity over and above the requirements for Expected LNG. The analysis of supply options illustrated that siting natural gas-fired generation locally and dispatching it off in favour of non-firm energy or market imports is the least cost option. However, this supply option may expose BC Hydro to GHG liability related to imported energy. The cost advantage of additional natural gas-fired generation in the North Coast needs to be weighed against such considerations. The development of clean or renewable energy resources along with clean capacity resources should be left as an option should higher levels of LNG loads materialize.

The analysis shows that a second 500 kV line to the North Coast to facilitate integrated system supply is not cost-effective at the load levels analyzed. It does, however, provide the North Coast with a high level of reliability and may be cost competitive should even higher amounts of LNG and other industrial loads interconnect in the North Coast.

Conclusions in this LNG and the North Coast section support Recommended Actions 11, 12 and 13 as described in Chapter 9.

6.6 Fort Nelson Supply and Electrification of the Horn River Basin

6.6.1 Introduction

Three HRB scenarios (high, mid and low), along with the Fort Nelson mid-load forecast, were used in the IRP analysis. The key IRP questions to address Fort Nelson supply and the electrification of the HRB are:

- What actions are required to meet the load growth in Fort Nelson considering the solution for Fort Nelson may be influenced by the HRB industrial loads and supply options?
- What is BC Hydro's strategy to prepare for significant potential load growth in the combined Fort Nelson and HRB regions? What actions are prudent in the absence of load certainty?
- How should BC Hydro respond to the subsection 2(h) *CEA* energy objective to encourage the switching from one kind of energy source to another that decreases GHG emissions in B.C.? This analysis considers the amount of CO_2 that is produced in the HRB under various gas production/energy supply scenarios and GHG reduction opportunities.

Additional considerations are: 1) the effect of electricity service to the HRB on the *CEA* 93 per cent clean or renewable energy objective; 2) the potential for additional benefits related to electricity supply to the HRB, such as access to new clean or renewable energy resources; and 3) the costs of providing such electricity supply to HRB.

The IRP analytical approach for addressing the Fort Nelson/HRB region's electricity supply requirements was to consider the LRB assumptions for these regions, both combined and separately, within various appropriate transmission networks that BC Hydro would be responsible for serving. The following sections describe the strategies for providing electricity service to the Fort Nelson and HRB regions, the analytical approach for assessing those strategies and the results of the analysis.

A detailed description of the approach and analysis is provided in Appendix 2E.

6.6.2 Load Scenarios

Three HRB electric load scenarios (High, Mid and Low), along with the Fort Nelson mid-load forecast, were used in the IRP analysis. Details of the Fort Nelson load forecasts and the HRB electrification load scenarios are provided in section 2.5.2

and Appendix 2E. The Fort Nelson load forecast is driven by a combination of residential, commercial and industrial growth, whereas the HRB scenarios are driven by potential gas production levels.

6.6.3 Alternative Supply Strategies

Three basic supply strategies were considered for the Fort Nelson/HRB analysis, as follows:

- Alternative 1: Supplying clean or renewable electricity by connecting these regions to the BC Hydro integrated system
- Alternative 2: Supplying electricity from within the Fort Nelson/HRB region
- Alternative 3: Supplying only Fort Nelson within the region (no supply service to the HRB)

Some of these basic alternative supply strategies were broken down further for a total of nine alternative supply strategies considered in the analysis, as described in Table 6-27.

Table 6-27 Summary of Fort Nelson/HRB Electricity Supply Strategies

Supply Alternative	Strategy Description
Alternative 1 BC Hydro Integrated System	Supply Fort Nelson/HRB with clean or renewable energy from the BC Hydro integrated system. With this strategy a new transmission line is built from the Peace Region to Fort Nelson and then to the HRB. This connects Fort Nelson and the HRB to the BC Hydro integrated system.
Alternative 2A Regional-Based: One Fort Nelson/HRB Network	The two regions of Fort Nelson and HRB are connected via a new transmission line. Generation is developed in one area to service both regions, or plants are dispersed in both regions. Various natural gas-fired generation options are examined, along with the option of combining local clean and natural gas-fired generation resources. The different options considered as part of this strategy include: • **2A1:** Supply with gas cogeneration – One cogeneration plant in Fort Nelson – Two cogeneration plants in Fort Nelson and HRB • **2A2:** Supply with CCGT in Fort Nelson • **2A3:** Supply with local clean energy (wind) and backed by SCGT in Fort Nelson
Alternative 2B Regional-Based: HRB alone	Both regions are supplied separately and from within their own region. A natural gas-fired cogeneration plant would service the HRB, and a new SCGT would service Fort Nelson or increased service from Alberta. The different options considered as part of this strategy include: • **2B:** Supply HRB as a separate network with a gas co-generation plant supply Fort Nelson with either: – a new SCGT in Fort Nelson, or – increased transmission service from Alberta
Alternative 3 Supply Fort Nelson alone; HRB producer self-supply	The HRB region is not serviced by BC Hydro, but instead companies self-supply their energy requirements. A new SCGT would service Fort Nelson or increased service from Alberta. The different options considered as part of this strategy include: • **3:** No service to HRB; supply Fort Nelson : – a new SCGT in Fort Nelson – increased transmission service from Alberta

6.6.4 Fort Nelson/HRB Analysis

The analysis presented in this section analyzes the economic costs of the alternative supply strategies for the Fort Nelson/HRB region as well as the costs and benefits of electrifying the HRB. The effect of the alternative supply strategies on BC Hydro's ability to meet the *CEA* 93 per cent clean or renewable objective and the risk of stranded assets is also assessed.

The Fort Nelson/HRB analysis extends to 2060, which is effectively 43 years from the assessed earliest ISD of new transmission needed to connect Fort Nelson/HRB to BC Hydro's integrated system. This approach allows for the testing of whether facilities such as transmission lines may become stranded, and whether the effect is material. It also provides insight into how the overall system might operate and what issues might arise. Where relevant, the three load scenarios identified earlier were analyzed across Market Scenarios 1, 2 and 3 as described in Chapter 5 and are presented for each of the strategies analyzed.

6.6.4.1 Economic Analysis

The base metric for much of the Fort Nelson/HRB economic analysis is the PV of the cost to serve the electricity load. The costs are expressed in PV in 2013 constant dollars for the period 2014 to 2060. Other assumptions include:

- For cogeneration plants, the heat is assumed to be sold at 85 per cent of the producer's avoided cost
- BC Hydro operates any required transmission networks
- The benefits of interconnecting the North Peace River cluster, estimated at $150 million as discussed in section 6.8.5.2, are used to offset the cost of the Northeast Transmission Line (**NETL**)

Total costs for the above combination of scenarios and strategies are presented in Table 6-28. It is important to note that comparing these costs cannot be done in isolation. There is a significant difference in loads served across some of the strategies, and such differences must be considered when making any conclusions based in whole or in part on the cost analysis.

The following observations can be made on the results of the economic analysis:

- Where BC Hydro is serving the full Fort Nelson/HRB region, (Columns [1] – [6]):

  - A local clean or renewable energy strategy of wind, backed by SCGTs (Alternative 2A3, Column [2]), is never the low-cost strategy
  - A supply strategy based on clean energy from the BC Hydro integrated system (Alternative 1, Column [1]) is relatively more expensive than other strategies under Market Scenarios 1 and 2, whereas the difference in cost is significantly reduced or eliminated under Market Scenario 3
  - Strategies relying on natural gas-fired generation are clearly the lowest cost under Market Scenarios 1 and 2, whereas the difference in cost is significantly reduced or eliminated under Market Scenario 3
  - Within the natural gas-fired generation strategies, the CCGT strategy (Column [5]) is in the middle of the cost range. This is because it does not rely on heat sales, as cogeneration facilities do. Cogeneration strategies with the highest heat sales load (in this set of analysis represented by Alternative 2A1(2), Column [4]) show up as having the best cost characteristics
- Where BC Hydro is serving Fort Nelson/HRB separately with different regional networks (the HRB strategy Alternative 2B), (Column [6]):
  - Analytical trends for cogeneration are similar to the full Fort Nelson/HRB network, but the costs are allocated across a smaller load

Table 6-28 BC Hydro's Total Cost to Serve Fort Nelson and HRB (PV $2013 million)

Column number	1	2	3	4	5	6	7[38]
Supply Alternative / Load & Market Scenario	1: BC Hydro System	2A3: Wind & SCGT	2A1(1): One Cogen Plant	2A1(2): Two Cogen Plants	2A2: CCGT	2B(1): One Cogen, New Fort Nelson SCGT	3(1): New Fort Nelson SCGT
	With Sequestration						
High-load Scenario; Market Scenario 1	12,197	11,154	9,560	8,322	9,847	8,853	392
High-load Scenario; Market Scenario 2	12,075	9,966	7,341	6,518	8,051	6,675	312
High-load Scenario; Market Scenario 3	12,360	12,440	11,960	10,272	11,789	10,562	480
Mid-load Scenario; Market Scenario 1	6,821	6,765	5,574	5,109	5,792	4,852	392
Mid-load Scenario; Market Scenario 2	6,698	6,049	4,328	4,004	4,710	3,854	312
Mid-load Scenario; Market Scenario 3	6,983	7,540	6,921	6,303	6,961	5,930	480
Low-load Scenario; Market Scenario 1	3,085	3,480	2,737	2,374	2,737	2,377	392
Low-load Scenario; Market Scenario 2	2,963	3,150	2,171	2,042	2,171	1,947	312
Low-load Scenario; Market Scenario 3	3,246	3,837	3,349	2,734	3,349	2,844	480

6.6.4.2 GHG Emission Production Analysis

In this section, the amounts of vented CO_2 as well as the costs and benefits of adopting clean energy supply strategies are analyzed.

The raw natural gas in the HRB has a relatively high concentration (12 per cent) of CO_2 which is currently removed from the natural gas during processing and vented to the atmosphere. In the case of the overall Fort Nelson/HRB analysis, the results

[38] For Fort Nelson supply, the lower of the two cost estimates was used. Refer to section 6.6.4.4 for more information.

include vented CO_2 from both formation and combustion processes. In the case of BC Hydro's share, the results are limited to the combustion-related CO_2. The modelled results for GHG production, as measured in megatonnes (**MT**)/year of vented CO_2, are insensitive to different Market Scenarios because the resources and dispatch are the same for each strategy analyzed.

Overall Fort Nelson/HRB GHG Emissions

As shown in Table 6-29, GHG emissions is highest with a strategy where the HRB development proceeds assuming producers self-supply their energy and heat requirements, and there is no CO_2 sequestration (Column [8]). In this strategy, the PV of MT of GHG is 273 MT, 195 MT and 98 MT for the high, mid and low-load scenarios, respectively. If carbon capture and sequestration (**CCS**) of formation CO_2 could be successfully implemented, those amounts can be reduced to 121 MT, 86 MT and 44 MT for the high, mid and low scenarios, respectively (Column [7]). This indicates that approximately 55 per cent of the total GHG emissions can be eliminated without BC Hydro's involvement, assuming that sequestration can be successfully implemented.

With BC Hydro's involvement by supplying the region clean or renewable energy via the integrated system, the GHG emissions can be further reduced to 73 MT, 59 MT and 31 MT for the high, mid and low scenarios, respectively (Column [1]). This represents a cumulative reduction of approximately 70 per cent (middle of Table 6-28), or an incremental improvement after sequestration of 30 to 40 per cent (bottom of Table 6-28).

The BC Hydro strategies based on natural gas-fired generation have less of an incremental impact; for example, the CCGT strategy (Column [5]) provides an incremental improvement over the producer self-supply sequestration strategy of 4 to 7 per cent; and successfully implemented cogeneration (Column [4]) somewhat higher. A BC Hydro local area isolated network clean strategy (Alternative 2A3), Column [2]) falls in between the system clean (Column [1]) and the natural gas-fired strategies (Columns [3] [6]), providing an incremental improvement over producer self-supply sequestration strategy of approximately 15 per cent).

Table 6-29 Overall Fort Nelson/HRB GHG Emissions

Column Number	1	2	3	4	5	6	7	8
Supply Alternative / Load Scenario	1: BC Hydro System	2A3: Wind & SCGT	2A1(1): One Cogen Plant	2A1(2): Two Cogen Plants	2A2: CCGT	2B(1): One Cogen, New Fort Nelson SCGT	3(1): New Fort Nelson SCGT	3(1): New Fort Nelson SCGT
	With Sequestration							No Seq'tn
CO_2 Vented (Formation and Combustion) (PV of MT)								
High-load Scenario	73.3	99.4	120.7	110.0	112.8	115.1	121.2	273.4
Mid-load Scenario	58.7	74.1	84.2	80.2	82.0	81.3	86.2	195.0
Low-load Scenario	30.5	37.7	42.1	36.8	42.1	41.4	44.3	97.8
GHG Reduction Without Sequestration (% of PV of MT)								
High-load Scenario	73.2	63.7	55.8	59.8	58.8	57.9	55.7	
Mid-load Scenario	69.9	62.0	56.8	58.9	58.0	58.3	55.8	
Low-load Scenario	68.8	61.4	56.9	62.4	56.9	57.6	54.7	
GHG Reduction With Sequestration (% of PVs of MT)								
High-load Scenario	39.5	18.0	0.4	9.3	6.9	5.0		
Mid-load Scenario	31.9	14.1	2.3	7.0	4.9	5.7		
Low-load Scenario	31.0	14.7	4.8	16.8	4.8	6.3		

BC Hydro Share of GHG Emissions

The CO_2 produced and vented from resources owned or acquired by BC Hydro is presented in Table 6-30. With these strategies, a supply strategy based on clean energy from the BC Hydro integrated system results in the lowest GHG emissions, even when considering the producer self-supply strategy.

Cogeneration strategies (Columns [3], [4], [6]) generally show higher CO_2 for BC Hydro than the CCGT strategy (Column [5]). It should be noted that BC Hydro's share of GHG emissions is not necessarily aligned with GHG emissions from the overall system. While cogeneration strategies show higher CO_2 than the CCGT strategy, much of the increase is due to the transfer of GHG liability from the host processing plant to BC Hydro's cogeneration plant. The cogeneration plants are less efficient for electricity production than CCGTs; however, they provide energy via heat sales, which reduces the GHG emissions at the host processing plant.

Table 6-30 CO_2 Produced by BC Hydro Facilities in Fort Nelson/HRB (PV of MT)

Column Number	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Supply Alternative / Load Scenario	**1: BC Hydro System**	**2A3: Wind & SCGT**	**2A1(1): One Co-gen Plant**	**2A1(2): Two Co-gen Plants**	**2A2: CCGT**	**2B(1): One Cogen, New Fort Nelson SCGT**	**3(1): New Fort Nelson SCGT**	**3(1): New Fort Nelson SCGT**
	With Sequestration							Without Seq'tn
High-load Scenario	0.3	26.4	54.4	54.3	39.7	50.4	2.1	2.1
Mid-load Scenario	0.3	15.7	32.2	35.7	23.6	28.4	2.1	2.1
Low-load Scenario	0.3	7.5	16.9	13.4	16.9	13.2	2.1	2.1

BC Hydro Cost per Tonne of GHG Reduction

A BC Hydro clean or renewable electricity strategy as compared to any of the natural gas-fired generation strategies can be considered as an incremental cost towards a reduction in Provincial GHG emissions.

Table 6-31 provides the cost per tonne to take the total BC Hydro cost for each strategy and scenario that includes natural gas-fired generation, to the equivalent scenario's system clean strategy (notionally a cost to upgrade each BC Hydro natural gas-fired generation strategy to clean electricity). For example, on the first row (High-load Scenario and Market Scenario 1), starting from Alternative 2A1(1) (the one cogen plant, Column [3]), the incremental cost to take that strategy and convert it to a system clean strategy would be $79/tonne. The green-shaded cells indicate strategies and scenarios that would benefit by being converted to system clean or renewable strategies, relative to the assumed incremental GHG costs of the $30/tonne B.C. carbon tax.

The results show for all Market Scenarios (1, 2 and 3):

- The additional cost for upgrading to a system clean strategy from any of the natural gas-fired generation strategies is generally higher than the expected GHG costs being offset
- The strategy of local clean energy with back-up natural gas-fired generation resources is economic compared to the system clean strategy in the low-load scenario based on the expected GHG costs being offset

Table 6-31 Incremental Cost ($/tonne) to Upgrade Natural Gas-Fired Generation Strategies to a System Clean Energy Strategy

Column Number	1	2	3	4	5	6	7	8
Supply Alternative / Load & Market Scenario	1: BC Hydro System	2A3: Wind & SCGT	2A1(1): One Cogen Plant	2A1(2): Two Cogen Plants	2A2: CCGT	2B(1): One Cogen, New Fort Nelson SCGT	3(1): New Fort Nelson SCGT	3(1): New Fort Nelson SCGT
High-load Scenario; Market Scenario 1; GHG $30/tonne of CO_2		70	79	102	90	103		
High-load Scenario; Market Scenario 2; GHG $30/tonne of CO_2		111	118	133	132	138		
High-load Scenario; Market Scenario 3; GHG $30/tonne of CO_2		27	37	69	44	66		
Mid-load Scenario; Market Scenario 1; GHG $30/tonne of CO_2		34	69	78	74	100		
Mid-load Scenario; Market Scenario 2; GHG $30/tonne of CO_2		72	104	106	115	131		
Mid-load Scenario; Market Scenario 3; GHG $30/tonne of CO_2		(6)	32	49	31	67		

Column Number	1	2	3	4	5	6	7	8
Low-load Scenario; Market Scenario 1; GHG $30/tonne of CO_2		(25)	51	84	51	85		
Low-load Scenario; Market Scenario 2; GHG $30/tonne of CO_2		4	78	100	78	109		
Low-load Scenario; Market Scenario 3; GHG $30/tonne of CO_2		(52)	24	69	24	61		

6.6.4.3 CEA 93 per cent Clean or Renewable Energy Objective

As noted in section 6.2, BC Hydro has sought to identify the optimal use of natural gas-fired generation that is available under the *CEA* 93 per cent clean or renewable energy objective. Table 6-32 presents the effect that each of the alternative supply strategies would have on BC Hydro's ability to meet the 93 per cent clean or renewable energy objective.

The analysis results are as follows:

- For the supply strategy based on BC Hydro supplying the region with clean energy from the integrated system (Column [1]), BC Hydro is above the *CEA* 93 per cent clean or renewable energy objective
- For the supply strategy for Fort Nelson alone (Columns [7] – [8]), BC Hydro is above the *CEA* 93 per cent clean or renewable energy objective
- For the natural gas-fired generation strategies (Columns [3] – [6]), BC Hydro is below the *CEA* 93 per cent clean or renewable energy objective in the mid and high-load scenarios, but above the *CEA* 93 per cent clean or renewable energy objective in the low-load scenario

- For Alternative 2A3 (Column [2]), regional clean or renewable energy supply with back-up natural gas-fired generation resources, BC Hydro is below the *CEA* 93 per cent clean or renewable energy objective only in the high-load scenarios; the other two scenarios are above the *CEA* 93 per cent clean or renewable energy objective

Given that the PV costs of serving a Fort Nelson/HRB low-load scenario (approximately $350 million) based on a natural gas-fired generation strategy are lower relative to a system-based clean energy strategy, BC Hydro may wish to preserve some of its 7 per cent non-clean headroom as an option to support supplying the Fort Nelson load growth and electrification of the HRB.

Table 6-32 Comparison of Alternatives against *CEA* 93 per cent Clean or Renewable Objective (percentage of BC Hydro System Clean Electricity, Average 2020 to 2030)

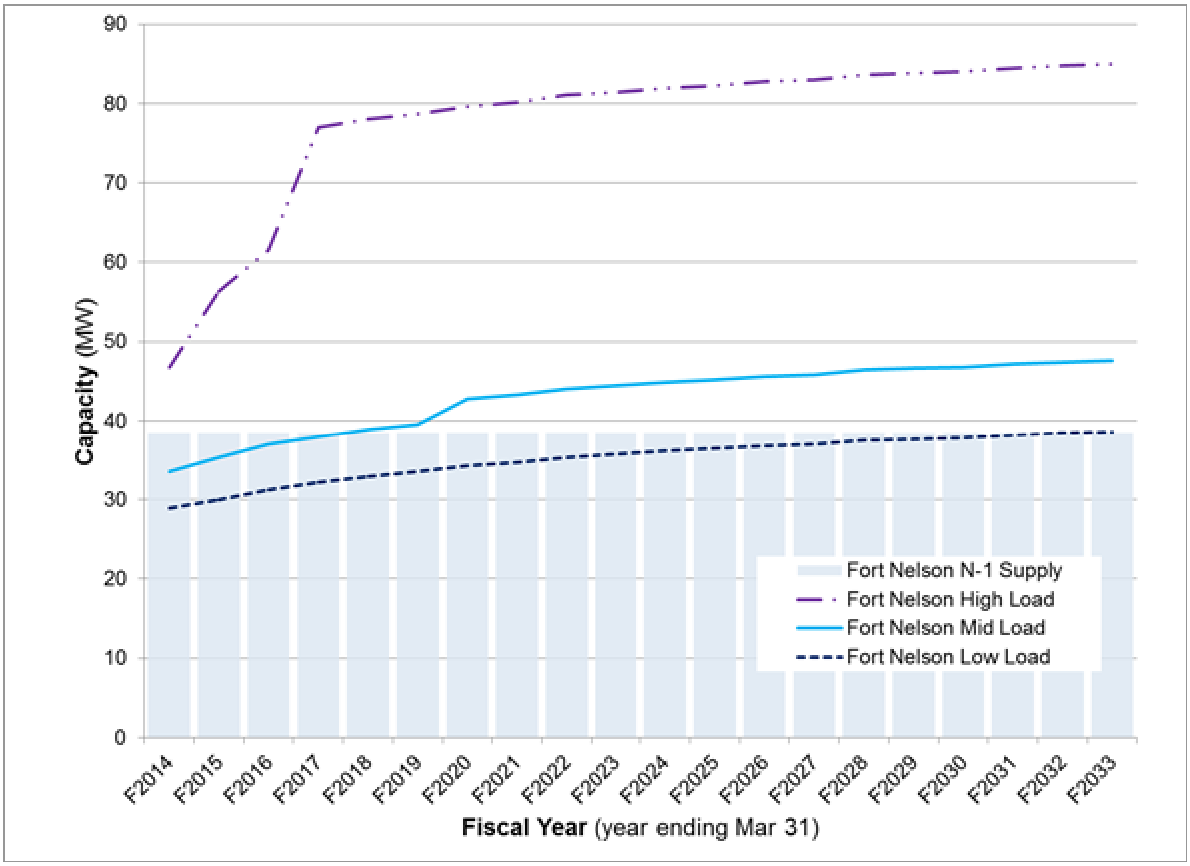
Column	1	2	3	4	5	6	7	8
Supply Alternative / Load Scenario	**1: BC Hydro System (%)**	**2A3: Wind & SCGT (%)**	**2A1(1): One Cogen Plant (%)**	**2A1(2): Two Cogen Plants (%)**	**2A2: CCGT (%)**	**2B(1): One Cogen, New Fort Nelson SCGT (%)**	**3(1): New Fort Nelson SCGT (%)**	**3(1): New Fort Nelson SCGT (%)**
	With Sequestration							Without Seq'tn
High-load Scenario	95.8	91.4	87.9	87.9	87.9	88.4	95.1	95.1
Mid-load Scenario	95.7	93.1	91.0	91.0	91.0	91.5	95.1	95.1
Low-load Scenario	95.6	94.2	93.1	93.1	93.1	93.5	95.1	95.1

6.6.4.4 Supplying Only Fort Nelson

Based on the mid and high-load forecasts for Fort Nelson, BC Hydro will need to add new capacity resources in order to maintain N-1 level of reliability as shown in Figure 6-13. Until a new supply solution is implemented, some Fort Nelson load may be subject to curtailable service. Accordingly, BC Hydro is working with the Alberta

Electric System Operator (**AESO**) to develop a Fort Nelson area load control process and remedial action schemes for supply shortfall events.

Figure 6-13 Fort Nelson Peak Load Scenarios and Existing Supply Capacity



For meeting load up to 73 MW on a firm basis, BC Hydro could construct new natural gas-fired peaking generation (i.e., SCGT) in Fort Nelson, or contract additional Fort Nelson Demand Transmission Service (**FTS**) service from Alberta via the AESO. The AESO indicated that it will not offer transmission service beyond 75 MW.

Analysis of Alternative 3 – Fort Nelson alone strategies - provides a comparison between a local SCGT and increased FTS service from the AESO. Table 6-33 presents results in a format similar to that in the previous sections. For this analysis, only the Fort Nelson mid-load forecast was considered.

Table 6-33 Total Supply Costs (PV, $2013 million, CO_2 Costs Not Included)

Load and Market Scenario	Supply Alternative 3(1): New Fort Nelson SCGT	Supply Alternative 3(2): AESO
Mid-load Scenario; Market Scenario 1	392	468
Mid-load Scenario; Market Scenario 2	312	388
Mid-load Scenario; Market Scenario 3	480	556

The results suggest that selecting an SCGT is always lower cost than increased FTS reliance on Alberta. In both cases, the incremental energy served would be thermal based. If BC Hydro does not undertake a strategy that involved electrifying the Fort Nelson/HRB region, adding peaking capacity or emergency capacity to FNG to meet Fort Nelson load on a firm basis is the least cost strategy.

6.6.4.5 Risk Analysis

The economic and GHG analyses presented earlier provide a range of results for differing uncertainties relating to load and market prices. This section looks at some of the residual risk elements that cannot be easily quantified, namely the risk if conditions unfold differently than planned.

A key risk from a long-term planning perspective is the risk of stranded assets. For example, for the supply strategy based on clean or renewable energy from the BC Hydro integrated system, if the Fort Nelson/HRB load that is planned for does not materialize, then the risk consequence would be:

- Low for the clean resources that may have been acquired, as these resources could be redeployed for meeting general integrated system load growth or supply retirements
- High for NETL, as there would be no alternative use for most of NETL (the segment between the Peace Region and North Peace Region (**NPR**) may

provide access to cost-effective clean energy resources to serve system requirements)

Similarly, in the case of supply strategies based on natural gas-fired cogeneration plants, the risk lies in the possibility that either the electrical load or the heat load does not materialize or continue at the level expected. In this case, the consequences would be:

- Very high for the cogeneration plant, which could lose one or both loads
- Zero for NETL from the Peace Region to FNG, because that transmission segment is not required

A comparison of stranded asset risk across the alternatives is summarized in Table 6-34.

Table 6-34 BC Hydro Stranded Asset Risk Matrix

Supply Strategies / Drivers for Stranded Asset Risk	System Clean	Local Clean / SCGT	CCGT at Fort Nelson	Cogen at Fort Nelson	Cogen in HRB
HRB Electrification	Yes	Yes	Yes	Yes	Yes
Host Cogeneration Competitiveness	No	No	No	Yes	Yes
Electricity Supply (capacity)	Low (redeploy)	High	High	High	Very high
Electricity Supply (energy)	Low (redeploy)	High	Low	High	Very high
GM Shrum to NPR Transmission	Low (redeploy)	Zero (N/A)	Zero (N/A)	Zero (N/A)	Zero (N/A)
NPR to Fort Nelson Transmission	High	High	Zero (N/A)	Zero (N/A)	Zero (N/A)
Fort Nelson to HRB Transmission	High (equal)	High (equal)	High (equal)	High (equal)	Zero (N/A)
Sub-transmission	High (equal)	High (equal)	High (equal)	High (equal)	High (equal)

If BC Hydro undertakes a strategy that does not involves electrifying the Fort Nelson/HRB region, the stranded asset risk is related to adding local generating capacity to serve future load that does not materialize when expected. As noted in section 2.5.2.1, there are significant uncertainties to the mid-load forecast for the

Fort Nelson/HRB region due to potential impacts from HRB development and/or other unexpected load developments. These uncertainties could defer the expected capacity shortfall to beyond F2018, or cause the shortfall to occur earlier than F2018. As such, any decision to add local generating capacity will be contingent on the load forecast becoming more certain.

6.6.5 Conclusions

BC Hydro studied two main alternatives for supplying the combined Fort Nelson/HRB loads under mid, high and low electrification load scenarios and under Market Scenarios 1, 2 and 3. BC Hydro believes a definitive decision on whether or not to electrify the HRB is not required at this time, and that it should continue to work with the B.C. Government and industry in assessing the merits of electrifying the HRB.

Conclusions in this Fort Nelson/HRB section support Recommended Actions 14 and 18 as described in Chapter 9.

6.7 General Electrification

6.7.1 Introduction

This section addresses the implications for BC Hydro of a scenario in which B.C. Government climate policy leads to a significant increase in the use of electricity to meet energy end use demands that are currently met by fossil fuels. Electrification could take place across the economy and across the province in end uses such as space and water heating, passenger and freight vehicles, and industrial equipment such as large compressors. The major potential industrial loads in the North Coast and the Fort Nelson/HRB which could shift from energy supply by fossil fuels to electricity have already been discussed in section 6.5 and section 6.6.

The section 2 *CEA* energy objectives include B.C.'s legislated target of reducing GHG emissions by at least 33 per cent below 2007 levels by 2020 and the long-term target of an 80 per cent reduction below 2007 levels by 2050. Achieving these targets will likely require large-scale fuel switching to low or zero emissions energy sources such as low emission or renewable electricity. Increased energy efficiency, and switching from fossil fuels with high emission intensities to those with lower emission intensities (i.e., coal to natural gas), will reduce emissions; however, the reductions required to get emissions to the targeted levels can likely only be achieved using low or zero emissions energy resources such as hydroelectric power, wind, solar, or fossil fuels with CCS. None of these resources can be used directly to meet energy needs such as space and water heating, industrial motor drives, and transportation. Instead they must be transformed into an energy carrier. Currently, the only commercially viable energy carrier is electricity. Therefore, large reductions in GHG emissions will require switching to electricity (i.e., "electrification") as a way to substitute low or zero emissions energy for the fossil fuels that power most homes, businesses and vehicles.

Climate policies targeting deep GHG emission reductions could result in a significant increase in electricity demand, and BC Hydro needs to consider the resource requirement to serve this demand growth. In addition, section 18 of the *CEA* provides for regulations to enable utilities to implement programs to support projects, programs, contracts or expenditures for the purposes of reducing GHG emissions in B.C., and this could include electrification[39]. However, electrification will increase costs to BC Hydro's existing ratepayers.

The key questions on general electrification in this IRP are:

- What is BC Hydro's strategy (what and when) to get ready for potential load growth driven by general electrification? What actions (if any) are prudent now in the absence of load certainty?

[39] To date, one regulation has been enacted under this section – the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012.

- What should BC Hydro's role be in reducing GHG emissions through electrification?

To address these questions BC Hydro retained two consultants, Energy and Environmental Economics Inc. (**E3**) and MK Jaccard and Associates, to study the associated issues and understand the potential for climate policy driven electrification. In 2010, E3 developed two climate policy scenarios for the WECC region and estimated the resulting impact on electricity demand in B.C. Details on the E3 scenarios can be found in Appendix 6B. In 2011, BC Hydro engaged MK Jaccard and Associates to model the impact of climate policy on energy-related GHG emissions in B.C. to provide further information on the end uses where electrical load could be expected to increase in response to various levels of carbon pricing. Details of the study can be found in Appendix 6C.

6.7.2 WECC Electrification Scenarios

E3 developed two climate policy scenarios, with low and high GHG emission reduction results, and evaluated how the response to these scenarios could impact energy consumption and production across the WECC region. The sector-by-sector GHG reduction assumptions made by E3 were based on expert qualitative knowledge of the relative costs of various GHG abatement measures, with conservation related savings generally coming first, and major capital stock turnover generally coming later in the modelled period.

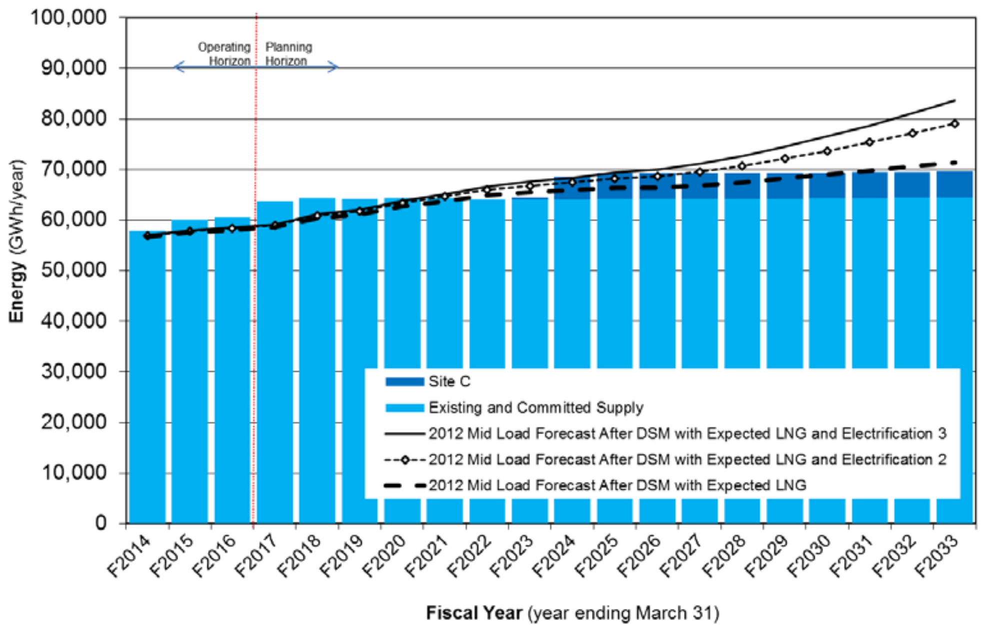
E3 worked closely with BC Hydro to minimize potential double counting of GHG emission savings, because BC Hydro has already included significant DSM savings in its load forecast and has made assumptions surrounding the adoption of electric vehicles and electrification in the oil and gas industry. The GHG emission savings estimates and additional electric load were incremental to what was assumed in BC Hydro's load forecast at the time (2010 Load Forecast) and any associated GHG emission reductions associated with serving the Fort Nelson/HRB and North Coast loads. This work has not been updated but is not expected to change any of the conclusions.

In the low GHG reduction scenario, a 30 per cent reduction in GHG emissions is achieved by 2050 relative to 2008. Offsets (reductions in non-energy related emissions, or reductions in other jurisdictions) can account for one-third of GHG emissions reductions; two-thirds are achieved through reductions in western states and provinces' fossil fuel based GHGs. For B.C., 35 per cent of total 2050 emissions savings come from offsets.

In the high GHG reduction scenario, an 80 per cent reduction in GHG emissions is achieved by 2050, relative to 2008. Of the 80 per cent, 30 per cent can be accounted for by offsets and the remaining 50 per cent is achieved through reductions in western states and provinces' fossil fuel based GHGs. B.C. meets the overall GHG target with 35 per cent of 2050 total emissions savings coming from offsets.

E3 developed electrification scenarios for WECC and produced the corresponding load scenarios for B.C. BC Hydro then adjusted these load scenarios to load and resource requirements on the BC Hydro system as shown in Figure 6-14. Electrification 2 corresponds to the low GHG reduction scenario and Electrification 3 corresponds to the high GHG reduction scenario.

Figure 6-14 Electrification Scenarios



A portion of the potential general electrification load is from the transportation sector. The corresponding capacity requirements are significant but it is assumed that there is opportunity to reduce this requirement by half by shifting charging to off peak hours, for example, by encouraging the installation of a timer which prevents the charging of vehicles during the system peak hours in the evening. Assuming that the charging cycle of the batteries is a few hours, there should be sufficient time to recharge the batteries overnight (outside of the system peak hours).

In both scenarios, electricity demand does not increase significantly until late in the 2020s. The large GHG savings that occur in the latter part of the modelled forecast horizon are due to major capital stock turnover, such as vehicles, building shells and furnaces (space heating).

6.7.3 Electrification Potential Review

BC Hydro engaged MK Jaccard and Associates to carry out an electrification potential review: a detailed analysis of how energy demands and in particular electricity would be likely to respond to climate policies of varying strength. The analysis used the CIMS model[40] to produce quantitative forecasts of technology market shares, electrification abatement and electricity demand. This model is a technologically detailed model that simulates realistic turnover of capital stock (e.g., acquisition and retirement of buildings, cars, boilers) and realistic consumer and firm decision-making when acquiring new capital stock, while integrating energy supply and demand and macro economic feedbacks. A version of CIMS specific to B.C. was used to simulate the evolution of energy using technologies to 2050 in each sector for each scenario of this study.

Three climate policy scenarios were simulated, with a carbon price acting as a proxy for a range of climate policies. The results of the analysis are consistent with the E3 scenarios. Major conclusions included:

- Under all GHG price scenarios, the increase in electricity demand is relatively modest in early years, due to the limitations of capital stock turnover, relatively low GHG prices, and low natural gas prices
- Electrification occurs across the economy, and in particular in the natural gas sector in early years
- Vehicle penetration is relatively low, even under high GHG price scenario, due to high capital costs

6.7.4 Analysis to Identify System Requirements

Based on the two consultant studies, the findings were that electrical demand could be as much as 50 per cent higher by 2050 than in the business-as-usual scenario. However, the rate of electrification is limited by capital stock turnover, and even very stringent climate policies do not result in significant increases in demand until well past 2020. This suggests that there will be a substantial time lag between shifts in

[40] CIMS is the name of an energy economy simulation model developed and maintained by the Energy and Materials Research Group at Simon Fraser University, B.C., Canada.

climate policy and the resulting electrification effects. As illustrated in Figure 6-14, potential general electrification load growth would be gradual, allowing BC Hydro to respond to load growth through a traditional planning process. Because of this, BC Hydro concluded that there was little benefit in analyzing the requirements for general electrification on its own as there is little near-term effect on the LRB.

However, for the purposes of stress testing the potential impact of electrification on system requirements, BC Hydro considered a scenario that combines the requirements of electrified LNG load in the North Coast, oil and gas production in the Northeast and general electrification. Table 6-35 summarizes the load and supply assumptions for this scenario.

Table 6-35 Electrification Load Scenario Summary

Load Assumptions	Supply Assumptions*
Mid-load forecast	Clean resources from system
LNG/North Coast: Expected LNG load of 3,000 GWh/year all assumed in the North Coast	Clean energy backed by local gas peakers as required
Northeast: High gas production and electrification scenario for Fort Nelson/Horn River Basin	Clean resources from system with Northeast Transmission Line
General Electrification: Electrification 3	Clean resources from system

*Supply assumed mostly clean as the intent of electrification is to reduce GHG emission

Based on the portfolio analysis on the combined electrification scenario, BC Hydro had sufficient amount of viable clean or renewable resources in B.C. to meet the electrification load. However, the unadjusted UEC at the POI for the marginal energy resource would climb to \$110/MWh by F2021, \$130/MWh by F2031 and \$200/MWh by F2041. In addition to the gas peakers targeted to serve LNG load, additional gas-fired generation or high cost pumped storage units would be needed by F2026 to meet capacity need. This scenario requires transmission upgrades starting in F2023 in addition to eight new high-voltage transmission lines by F2040. When comparing this electrification scenario to the mid gap no LNG portfolio, the incremental annual cost in F2031 would be about $2.5 billion (real $F2013). All these costs and factors should be considered when the Province evaluates the tools available for reducing GHG emissions.

6.7.5 Conclusions

Economy-wide electrification could contribute significantly to long-term GHG reductions as part of a climate change strategy to achieve deep cuts in emissions, however, this would result in significant increases in electricity rates.

BC Hydro can support the government's Climate Action Plan by being prepared to meet the increased load associated with electrification (e.g., DCAT will serve key industrial customers, among others, who have demonstrated their commitment to electrifying their traditionally gas-powered facilities), and by working with the B.C. Government to examine electrification through potential programs enabled by regulation under section 18 of the *CEA*. The analysis carried out for this IRP indicates that a move towards general electrification is unlikely to increase load significantly in the next 10 years, and therefore does not require BC Hydro to plan for significant near term resource additions to meet load growth from electrification.

In the next 10 years, however, there are some preparatory actions that BC Hydro could undertake in support of government climate policy objectives:

- Continue to provide analysis and support to the B.C. Government, such as the electrification potential review carried out for this IRP that identify where electrification would be expected to occur in response to climate policy, and any analysis on the cost of electrification related policies
- Continue distribution system studies and related activities to ensure that BC Hydro is able to supply the increased loads (e.g., electric vehicles, heat pumps) that could result from significant electrification
- Continue to investigate the opportunity of managing capacity requirements from electric vehicles such as through the use of timers.

In addition, BC Hydro can support government climate policy objectives in the following ways:

- Work with the B.C. Government, the ports and industry to expand the availability of shore power to shipping at B.C. ports
- Work with the B.C. Government, local governments and other partners to manage the installation of 13 electric vehicle fast-charging stations across B.C.

These conclusions align with the actions presented on general electrification in section 9.5.1.

6.8 Transmission

6.8.1 Introduction

The transmission grid that delivers electricity to BC Hydro's customers is divided into three major infrastructure categories: 1) the high-voltage bulk transmission network, which carries high-voltage electricity from where it is generated to the transmission and switching substations in cities and towns; 2) the regional transmission network, which transfers high-voltage electricity to major delivery points around the cities, towns and industrial centres; and 3) the distribution network, which delivers lower voltage electricity to individual customers. The IRP analysis focuses on the high-voltage bulk transmission system (primarily 230 kV and above).

Pursuant to subsection 3(2) of the *CEA*, the IRP is required to include a description of BC Hydro's infrastructure and capacity needs for electricity transmission over 30 years. There is also a requirement in subsection 3(3) of the *CEA* to include an assessment of the potential for developing electricity generation from clean or renewable resources in B.C., grouped by geographic area (also referred to as generation clusters).

This IRP addresses the following transmission-related questions:

- What are the transmission requirements to support load and generation build-out in the Province?
- Whether, and to what degree, BC Hydro should take a more proactive approach to building transmission infrastructure? This proactive approach could be in response to additional need identified in different load scenarios or to pre-build transmission to areas where there are potential generation clusters.

When assessing future bulk transmission system requirements, BC Hydro considers the following:

- The need to maintain a mandatory level of reliability for customers
- Growth in demand including DSM impacts by geographic area
- Potential location and size of new generation resources
- The need to minimize electricity losses that occur when electricity is carried over long distances
- The expected retirement or refurbishment of existing transmission and generation resources

In addition to identifying the transmission system reinforcements required under the expected load/resource assumptions, the IRP needs to address the following risks given the long lead times required for planning, siting and constructing transmission projects, needing to ensure the system can accommodate potential future requirements and to build an efficient system:

- New demand for electricity may develop sooner than transmission lines can be built to provide the service
- Generation projects may be completed before transmission lines (which typically have longer lead times) are ready

- Generation projects may develop in a way that leads to building segmented transmission lines that are inefficient and have avoidable environmental footprints

The first two risks relate to having sufficient transmission capability when needed, whereas the third risk relates to having an inefficient transmission system.

BC Hydro addresses the first two risks by analyzing transmission requirements taking into account different load scenarios requirements and contingency conditions to identify prudent actions for preparing to serve potential larger loads. These contingency conditions include:

- An assessment of potential need to develop alternative sources of supply (transmission contingency plan) to mitigate the risk that a planned transmission project is not going to be completed in time
- An assessment of potential need to advance planned transmission projects to mitigate the risk that the projects are needed sooner than expected. BC Hydro prepares specific CRPs, which are submitted to the BCUC for approval pursuant to the Open Access Transmission Tariff (**OATT**) for the purpose to establish a queue position for a transmission service request because of the long transmission lead time. The CRP(s) submitted to the BCUC must consider scenarios that reasonably test the transmission pathways that occur based on the possibility of resources and loads in specific locations. Without transmission planning formally including the CRPs in its planning processes and ensuring that the associated transmission requirements are being maintained, BC Hydro's CRPs would be ineffectual.

BC Hydro addresses the third risk by analyzing the cost-effectiveness of pre-building transmission to access generation clusters and discussing the pros and cons associated with a proactive approach to advance transmission infrastructures.

In this section, the results of the IRP analysis on transmission requirement are presented by:

- First, examining the existing transmission infrastructure to identify the required upgrades for meeting future electricity demands under mid gap conditions in a no LNG scenario and assessing the need for transmission contingency plans
- Second, investigating the effects of the Expected LNG load on transmission infrastructures need and timing especially in the North Coast and assessing the need for transmission contingency plans
- Third, examining the transmission requirements under different contingency conditions related to load and DSM uncertainty, pumped storage uncertainty, and higher than expected LNG loads on the North Coast. The results of this analysis provide a preliminary assessment of transmission implications in the CRPs.
- Finally, analyzing the cost-effectiveness of pre-building transmission to access generation clusters

6.8.2 Transmission Analysis: Mid Gap

BC Hydro reviewed a set of portfolios that meet the mid gap conditions in a scenario without LNG, and identified the associated bulk transmission requirements[41]. This review led to the following conclusions:

North Interior Corridor

Non-wire transmission upgrades, such as adding shunt compensation at Williston (**WSN**) and Kelly Lake Substation (**KLY**) and/or enhancing series compensation at Kennedy Capacitor Station (**KDY**) and McLease Capacitor Station (**MLS**), are likely sufficient to provide the needed incremental transfer capability on this path and will

[41] The transmission implications for the South Peace regional transmission system and the Fort Nelson/HRB regions are address elsewhere in this IRP.

defer the need for new transmission lines to beyond the planning horizon. Analysis results and rationale are as follows:

- Flow of electrical power from GMS towards WSN and from WSN towards KLY is expected to exceed the Total Transfer Capability (**TTC**) of the GMS-WSN and/or WSN-KLY transmission cut-planes
- For portfolios that do not include Site C, incremental transfer capability has to be provided by F2032
- For portfolios that include Site C, the required date for incremental transfer capability is advanced from F2032 to F2024

Since the proposed reinforcements are non-wire upgrades, BC Hydro considers the risk of not meeting the F2024 ISD to be low.

South Interior Corridor

The key transmission reinforcements in the South Interior bulk transmission grid are non-wire upgrades to provide voltage support by adding series compensation on 500 kV lines 5L91 and 5L98, which are triggered by Revelstoke Unit 6 coming online. In the BRP, as BC Hydro pursues the DSM target and Site C, Revelstoke Unit 6 is needed in F2031.

Interior to Lower Mainland

Addition of 5L83 in F2016 will increase TTC of the Interior to Lower Mainland (**ILM**) project to approximately 6,550 MW. The regional LRB shown in section 2.5.3 for the Coastal region demonstrates that in the absence of incremental DSM, and new or renewed dependable capacity supply in the Coastal region, new transmission transfer capability beyond the capability provided by 5L83 may be required by F2022. However, when the expected EPA renewals and incremental savings from the DSM target are included in the resource portfolios, the power flow on the Interior to Lower Mainland transmission cut-plane is not expected to exceed the TTC that 5L83 provides until F2030.

Non-wire transmission upgrades such as addition of shunt compensation at Nicola (**NIC**) and Meridian (**MDN**) substations can provide incremental transfer capability.

In addition to the non-wire upgrades, a need for further reinforcement of the ILM grid by building a new 500 kV series compensated transmission line (5L46) between KLY and Cheekye Substation (**CKY**) near Squamish is identified as early as F2034 if pumped storage resources in the Lower Mainland are not used or available to displace the need for capacity resources from the Interior. See section 6.8.4 for a discussion of the effect of pumped storage in the Lower Mainland on transmission planning.

Lower Mainland to Vancouver Island

The main supply routes for transferring power from Lower Mainland to Vancouver Island are two 500 kV, one 230 kV and one 132 kV submarine cables. The regional LRB shown in section 2.5.4 shows that without incremental DSM, renewal of the EPA for Island Generation project (natural gas-fired combined cycle plant) or new on-island dependable capacity generation, new transmission upgrades between the Lower Mainland and Vancouver Island may be required by F2023. However, when these expected resources are included in the portfolios, there is no need to reinforce the transmission links between the Lower Mainland and Vancouver Island over the planning horizon. It is noted that the EPA renewal assumption for Island Generation project (F2023 expiry) has a significant effect on the timing for additional transmission requirement to Vancouver Island. However, BC Hydro considers that the likelihood of a combined contingency conditions resulting in a need to advance transmission infrastructures in this IRP is low.

North Coast

Most of the LNG development is expected in the North Coast. The North Coast is supplied by a radial transmission line from Prince George to Terrace that consists of the following three 500 kV circuits: 5L61 from WSN to Glenanna (**GLN**); 5L62 from GLN to Telkwa (**TKW**); and 5L63 from TKW to SKA in Terrace. As shown in section 2.5.1 and confirmed with analysis on portfolios meeting the mid gap, in the absence of new LNG loads on the North Coast, the 500 kV path from WSN to Skeena (**SKA**) is expected to be sufficient over the planning horizon.

6.8.3 Transmission Analysis: Mid Gap with Expected LNG

Section 6.5 discusses the unique planning challenges and supply strategies (additional resource requirements) for LNG and the North Coast. In section 6.5, it is identified that the mid gap scenario with the expected LNG load would require voltage support and reinforcement on the transmission line to the North Coast. The reinforcements include series compensation of 5L61, 5L62, and 5L63, plus voltage support and transformer additions in the existing BC Hydro substations by F2020. Since the proposed reinforcements are non-wire upgrades, BC Hydro considers the risk of not meeting the F2020 ISD to be low.

6.8.4 Transmission Large Gap Analysis

In addition to the mid gap analysis, the transmission requirements under contingency conditions (referred to as the large gap) and for higher than expected LNG load were also studied to inform the development of a robust transmission plan. These conditions are described below and the results of the transmission analysis for these conditions are summarized in the following sections. Section 6.9 provides the rationale for considering the large gap scenario in more detail.

- Large Gap: This scenario addresses the contingency event where a gap larger than expected results from the high-load forecast and low DSM saving level. For transmission planning, the large gap analysis further tests the transmission implications if pumped storage in the Lower Mainland is not able to be developed in a significant manner and is replaced by SCGTs in the Kelly Lake region.

As described in section 4.4.6.1, generic pumped storage units in the Lower Mainland are used as a clean energy or renewable capacity resource in the IRP analysis to meet capacity need in the portfolios after considering the capacity from Site C, Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and SCGTs (in portfolios where 7 per cent non-clean headroom is used) are selected. The addition of pumped storage units allows part of the peak demand in the Lower Mainland to be met locally, which in turn reduces the need for transmission to bring generation capacity into Lower Mainland. In general, the addition of Lower Mainland pumped storage units has the effect of indirectly deferring transmission requirements along the ILM corridors and potentially the GMS-WSN-KLY corridor as well, and deferring the need for other local capacity resources.

Given that the development of pumped storage is unproven in B.C. (see section 4.4.6.1), prudent transmission planning must consider a contingency scenario where pumped storage is not proven out. Since the default capacity option to replace pumped storage is natural gas-fired generation, the remaining capacity need after considering the capacity from the projects listed above are met with SCGTs; such portfolios were created to understand the effects of this contingent event (i.e., without pumped storage). While siting gas in Lower Mainland would be beneficial because of its proximity to load centre and reduces the need for transmission to bring generation capacity into the Lower Mainland, permitting is expected to be very difficult as discussed in section 6.2.5. Other locations for siting gas, such as Kelly Lake and North Coast, would have implications on transmission requirements. The portfolio created assumes SCGTs are sited in the Kelly Lake region. If these units are sited somewhere else, they could advance transmission lines in other corridors.

- Higher than Expected LNG load scenario: This scenario contemplates a higher level of LNG load up to 6,600 GWh/year (800 MW) developing on the North Coast.

6.8.4.1 Large Gap Scenario

North Interior Corridor

The results of the portfolio analysis for the large gap show that the need for voltage support along the GMS-WSN-KLY transmission corridor is advanced from F2024 to F2020. In these portfolios, additional 500 kV transmission lines between GMS and WSN (5L8) and between WSN and KLY (5L14) are also required as early as F2029.

South Interior Corridor

As discussed earlier, the compensation of 500 kV lines 5L91 and 5L98 are triggered by Revelstoke Unit 6 coming online. In the large gap scenario, the ISD for Revelstoke Unit 6 is advanced to its earliest ISD of F2021.

Interior to Lower Mainland

In the large gap scenario, the need for non-wire upgrades of the ILM transmission grid is advanced from F2030 to F2025. The new ILM line 5L46 is advanced from F2034 to F2029 when pumped storage in the Lower Mainland is not used or available to displace capacity resources from the Interior.

Lower Mainland to Vancouver Island

As with the mid gap analysis, there is no need to reinforce the transmission links between the Lower Mainland over the planning horizon assuming incremental low DSM savings and renewal of the Island Generation EPA.

6.8.4.2 Higher than Expected LNG Load

For the North Coast, higher level of LNG load up to 6,600 GWh/year (800 MW) and corresponding supply options including transmission requirements are discussed in section 6.5. Higher levels of LNG load will likely require either additional transmission reinforcements or local dependable (gas-fired) generation. The System Supply option with a second 500 kV line to the North Coast is more costly to alternative options of siting gas-fired generation locally. However, it does provide the North Coast with the high level of reliability.

6.8.5 Generation Cluster Analysis

Pursuant to subsection 3(3) of the *CEA* requirements to include an assessment of the potential for developing electricity generation from clean or renewable resources in B.C. grouped by geographic area, BC Hydro assesses where large potential for low cost clean generation resources exists in B.C. (these areas are referred to as clusters). As part of this IRP, BC Hydro analyzed the cost-effectiveness of pre-building transmission to access clusters and the pros and cons associated with a proactive approach to advance these infrastructures.

In the traditional evaluation framework used in resource planning, transmission capability is generally added in response to interconnection requests from individual generation projects. Building a common transmission line to access a cluster of projects was done only if opportunity arises, such as when multiple requests are made at similar time. With the cluster approach, it is assumed that a new bulk transmission line and substation would be pre-built to connect the projects within a cluster to the existing transmission grid. A potential benefit of the cluster approach is that it reduces the environmental footprint by minimizing the number of transmission corridors in an area. However, it also carries significant risk in that the transmission investment could be stranded or under-utilized if the generation resources did not develop as expected.

This IRP cluster analysis considers the cost benefit of pre-building transmission to areas with high concentration of generation resources by comparing portfolios created according to the following two approaches:

- **Bundle approach:** The traditional evaluation framework used in resource planning reflects the current approach to interconnecting individual generation projects to existing transmission grid. Each project within a bundle has a separate transmission connection to the system.
- **Cluster approach:** Pre-building bulk transmission into a region of high generation resource potential. A cluster is a geographic area where there is high energy and/or capacity density.

6.8.5.1 Cluster Identification

To identify areas of high generation resource potential (referred to as clusters), the following criteria was used as a guide: 1) a minimum capacity density of 0.06 MW/km^2, 2) a minimum generating capacity of 500 MW, and 3) at least 50 km away from the bulk transmission system.

For each identified cluster, a central node which represents a potential new transmission substation and collector hub for the electricity generated from the resources within the cluster was selected based on geography, proximity of generation resources and professional judgement. The length and cost of a bulk transmission line connecting the central node to the existing transmission grid were then determined. These line options are referred to as T3 options[42] in the following discussion. The cluster and T3 option analysis was conducted by Kerr Wood Leidal, and the report describing the approach and results is included in Appendix 6D.

The analysis identified nine clusters:

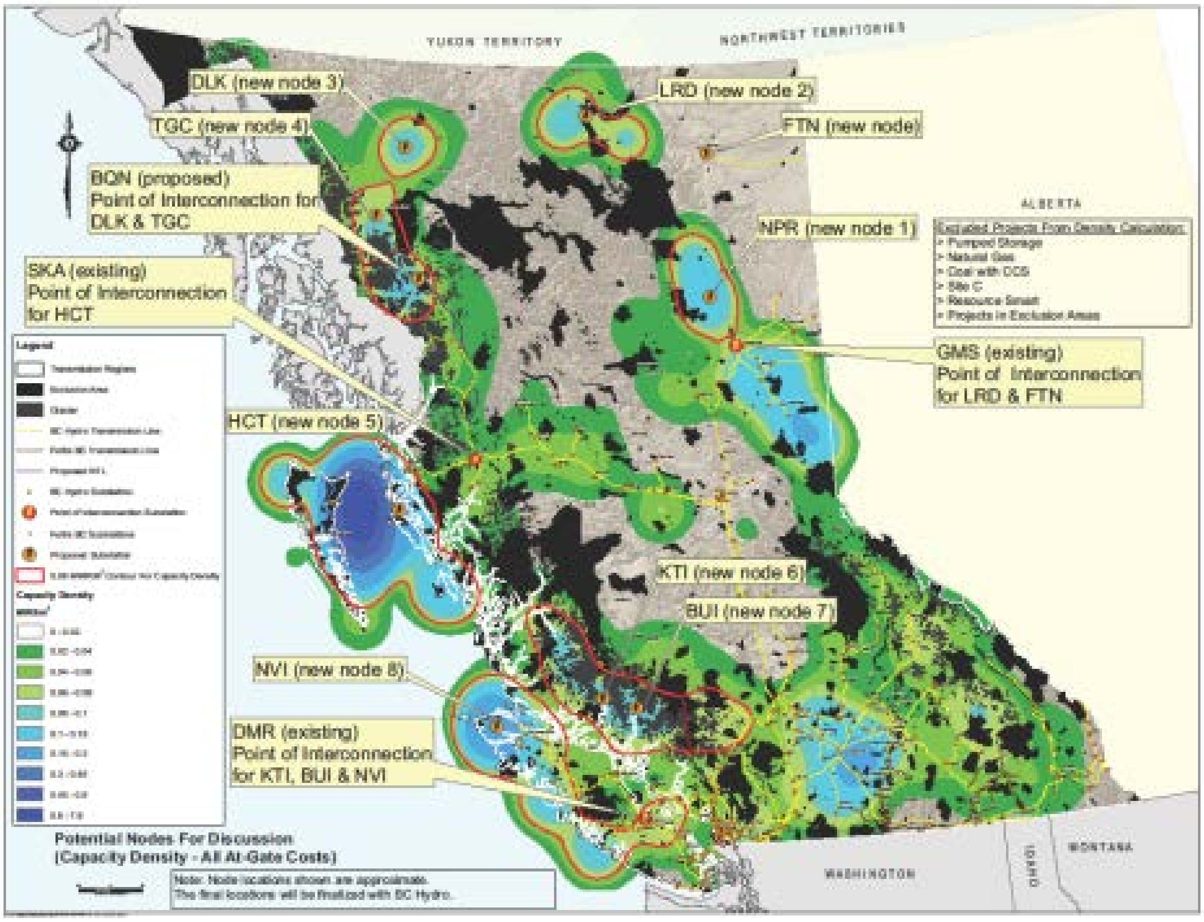
[42] The term ‘T3 Options’ builds off terminology used by BC Hydro in its resource options assessment to categorize the types of power lines required to connect new generation projects to the existing transmission grid. Refer to Appendix 6D for more information.

- North Peace River (**NPR**), connecting to GMS
- Fort Nelson (**FTN**)[43] , connecting to NPR
- Liard (**LRD**), connecting first to FTN and then to NPR
- Telegraph Creek (**TGC**), connecting to the future Bob Quinn Substation (**BQN**)
- Dease Lake (**DLK**), connecting to TGC
- Hecate (**HCT**), connecting to the SKA
- Knight Inlet (**KTI**), connecting to the Dunsmuir Substation (**DMR**) on Vancouver Island
- Bute Inlet (**BUI**), connecting to DMR
- North Vancouver Island (**NVI**), connecting to DMR

Figure 6-15 shows the central nodes of the clusters (labelled as "new nodes") and the area covered by each cluster (delineated by the red border). In Figure 6-15, many of the clusters are located in areas less densely covered by transmission, and hence have reduced access to the existing transmission system.

[43] The region around Fort Nelson did not have greater than 500 MW of potential generation resources in close proximity and therefore did not meet the definition of a generation cluster. However, it is recognized as having load growth potential and was therefore considered in the analysis.

Figure 6-15 Cluster Analysis Nodes



6.8.5.2 Portfolio Cost Analysis

The analysis presented here is based on an older vintage LRB mid gap, which contains a much larger load-resource gap than the mid gap LRB described in this IRP. However, the conclusions still hold true for when additional resources are needed in the future.

To analyze whether there is a potential benefit of pre-building transmission for generation clusters, a 30-year portfolio was created using the cluster approach. The System Optimizer model was given the option to select T3 options, and the cost of interconnection for generation resources was adjusted to the central nodes. The PV of this cluster portfolio was then compared to the PV of the corresponding portfolio with a bundle approach.

The comparison shows that the cluster approach results in a lower PV than the bundle approach (less than 2 per cent difference in PV for a 30-year portfolio). With the mid gap LRB used in this IRP, the difference in PV between the cluster and bundle approach would likely be reduced, or even swing in favour of the bundle approach as the much lower resource gap would lower the utilization of the T3 line in the cluster approach but still incur the entire cost of the T3 line.

It should be noted that the portfolio analysis is based on the resource selection being optimized given perfect foresight of future conditions within the portfolio construct. The costs and availability of resources analyzed represent planning level estimates that are sufficient for comparing resource options but this information is highly uncertain/unreliable for predicting which and where resources would be developed. In addition and in practice, the cluster approach also assumes the risk of stranded or under-utilized transmission assets that represent significant expenditures. The cluster approach may also have potential negative impacts on bidding behaviour in a potential future acquisition process, which could erode any benefits.

Given all of the above considerations, the difference in portfolio PV results is not significant enough to support a cluster approach.

An additional analysis was conducted for the NPR cluster to determine if any benefits of the NRP cluster could offset the cost of NETL which is being contemplated in the NPR area. An additional portfolio allowing only the NPR cluster was created and compared to the bundle approach, again with the older vintage of LRB mid gap. In this comparison, the PV of the NPR cluster portfolio was marginally higher than the bundle approach, suggesting that the benefit of building out the NPR cluster does not fully offset the cost of the GMS to NPR transmission line over the planning horizon. However, the difference in portfolio cost without the cost of the T3 line from the Peace Region could be used to offset the cost of NETL because

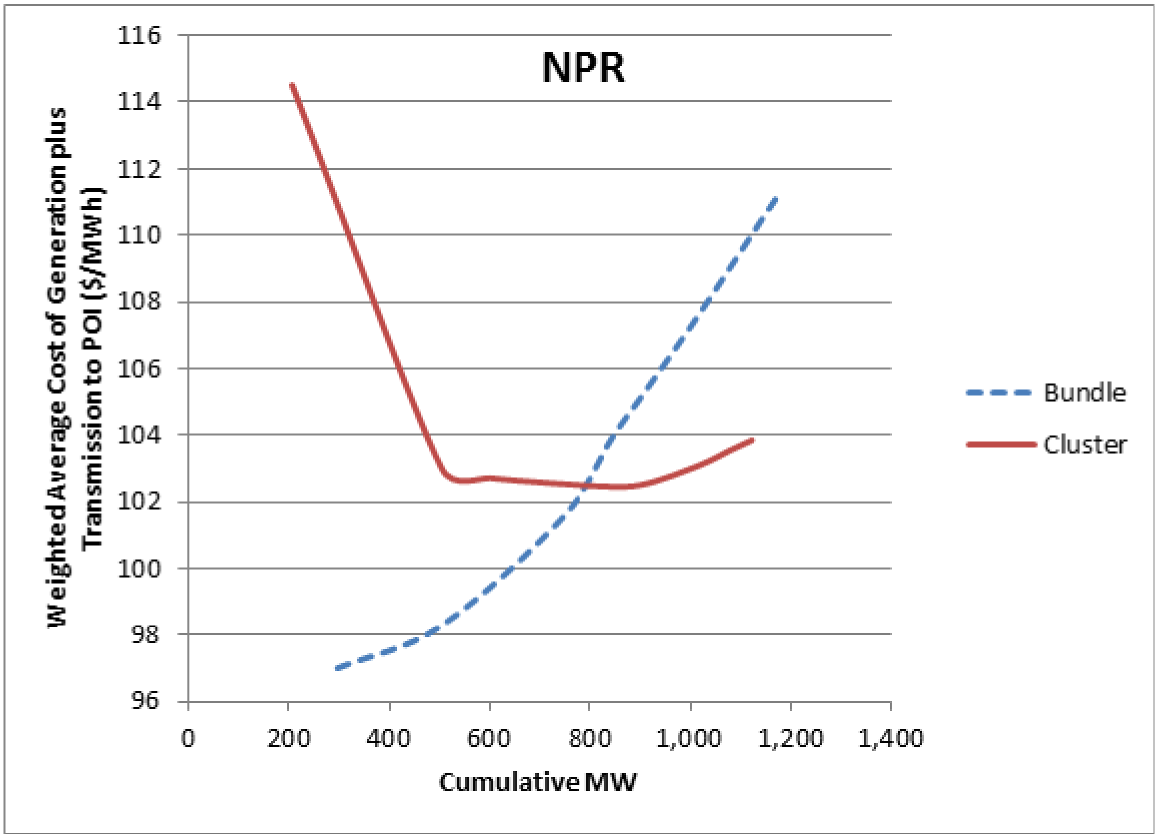
NETL enables access to the NPR cluster. By assuming the annual benefit at the end of the 30-year portfolio persists until the end of the project life of NETL, the benefit associated with the NPR cluster is about $150 million.

6.8.5.3 Simple Cost Analysis for Clusters

In addition to the portfolio analysis described in section 6.8.5.2, a simple analysis of estimating potential cost savings for the cluster approach was completed to understand potential benefits in the long run (beyond the planning timeframe). The potential cost savings were estimated as the annual difference in cost, between the two approaches, incurred up to the POI at existing transmission grid (i.e., the bundle approach includes the generation resource cost and interconnection cost (T1) to the POI; the cluster approach includes the generation resource cost and interconnection cost (T2) to T3 and the cost of T3 from the respective central nodes to POI.

As an example of the analysis, Figure 6-16 shows a comparison of costs for the bundle approach versus the cluster approach for a 500 kV T3 option connecting to the NPR node. For the bundle approach, the weighted-average cost of resources increases as increasingly more expensive projects are interconnected. The cluster approach has a higher weighed average cost than the bundle approach when only a few projects are interconnected, but the cost decreases as more resources are interconnected as utilization of the T3 line is increased. At some point, the weighted-average cost for the cluster approach may increase again, as the addition of more expensive resources outweigh the benefit of higher utilization of T3 line. In this example, 800 MW of resources have to be built for the cluster approach to yield lower average cost than the bundle approach. This speaks to the risk of stranded assets if the T3 line is built, but the assumed generation resources in the cluster are not needed or are not developed.

Figure 6-16 Comparison of Weighted Average Annualized Cost for the Bundle Versus Cluster Approach



The resulting weighted average costs and total costs from the two build out approaches for two T3 sizes (i.e., 230 kV and 500 kV where meaningful) are summarized in Table 6-36 to Table 6-39. Clusters which depended on other clusters to be built first (e.g., DLK) were not included in this simple analysis. The annualized costs reflect the condition when the lines are close to fully utilized. As shown in these tables, the cluster approach is generally of lower cost than the bundle approach for clusters studied, except for the NPR and NVI clusters with a 230 kV line. This confirms the intuition that the cluster approach generally has a cost advantage in the long run when the line is fully utilized. However, there is uncertainty regarding resource development leading to risk of stranded/underutilized asset, and uncertainty as to when benefit can outweigh cost.

Table 6-36 UEC Cost Comparison for Bundle Approach versus Cluster Approach for a 230 kV Line

Cluster	Bundle	Cluster (230 kV)
	UEC of generation + T1 ($/MWh)	UEC of generation + T2 +T3 ($/MWh)
NPR	97	109
TGC	286	174
NVI	129	145
KTI	142	94
BUI	124	88

Table 6-37 UEC Cost Comparison for Bundle Approach versus Cluster Approach for a 500 kV Line

Cluster	Bundle	Cluster (500 kV)
	UEC of generation + T1 ($/MWh)	UEC of generation + T2 +T3 ($/MWh)
NPR	111	104
TGC	794	348
HCT	132	128
NVI	137	133
KTI	301	177
BUI	266	169

Table 6-38 Total Cost Comparison for Bundle Approach versus Cluster Approach for a 230 kV Line

Cluster	Bundle	Cluster (230 kV)
	Cost of generation + T1 ($ million)	Cost of generation + T2 +T3 ($ million)
NPR	99	78
TGC	304	181
NVI	96	93
KTI	177	112
BUI	151	97

Table 6-39 Total Cost Comparison for Bundle Approach versus Cluster Approach for a 500 kV Line

Cluster	Bundle	Cluster (500 kV)
	Cost of generation + T1 ($ million)	Cost of generation + T2 +T3 ($ million)
NPR	432	393
TGC	2,389	1,047
HCT	317	306
NVI	320	356
KTI	1377	802
BUI	835	532

6.8.5.4 Transmission for Clusters

The construction of transmission lines has a long lead time and delays to the in-service date of a transmission line may have effects on BC Hydro's ability to deliver supply to customers. Given the potential early need for some of the lines identified in this analysis, it is beneficial to begin developing the lines and corridors to minimize the amount of time required to bring them into service when their need is confirmed.

The IRP analysis concludes that there could be marginal financial benefits in pre-building transmission into clusters of generation resources over the 30-year planning horizon. It also has the potential to reduce environmental footprints somewhat as a result of optimal transmission configurations. However, there are also significant risks associated with pre-building transmission for generation clusters that include:

- Stranded transmission investment if the expected generation projects do not materialize
- Potential negative impacts on acquisition process bidding behaviour, which could erode any financial benefit to pre-building

To reap some potential pre-building benefits while minimizing risk, BC Hydro could evaluate building adequate transmission to the identified high potential generation cluster regions during future acquisition processes if and when projects in these regions are proposed. The NPR cluster could provide an estimated $150 million of benefit to offset the cost of NETL.

6.8.6 Conclusions

The IRP analysis concludes that the following transmission reinforcements should be considered in this IRP. Detailed studies are required to finalize the scope and cost of the required upgrades:

North Interior Corridor:

- Non-wire upgrades to the existing transmission lines and substations on the GMS-WSN-KLY 500 kV transmission system are expected to be required by F2024 (mid gap), but may be required as early as F2020 (large gap). BC Hydro should reinforce this corridor by F2024. Although developing alternative supply options (transmission contingency plan) are not required at this time, studies to keep an early ISD of F2020 open for the non-wire upgrades on the GMS-WSN-KLY corridor may be initiated as part of BC Hydro's CRPs.
- New 500 kV transmission from GMS to KLY is not expected over the planning horizon, although the large gap scenarios indicate new transmission may be required by F2029. Given the long lead time before new transmission is required under the large gap scenario, there is no need to develop contingency plans at this time.

South Interior Corridor:

- Non-wire upgrades to the 500 kV lines of 5L91 and 5L98 are needed to support the delivery of power from Revelstoke Unit 6, which is expected to be required in F2031 in the BRP and as early as the earliest ISD in F2021 (large gap). A transmission contingency plan is not required and studies to ensure the timing for these upgrades to match the Revelstoke Unit 6 earliest ISD will likely be initiated as part of BC Hydro's CRPs.

Interior to Lower Mainland:

- Following completion of 5L83, no new upgrades are expected to be required until F2030. However, in the large gap scenario the non-wire upgrades to the ILM transmission grid will be required as early as F2025. A transmission contingency plan is not required and studies to define the scope and cost of the upgrades for an early ISD will likely be initiated as part of BC Hydro's CRPs.

Lower Mainland to Vancouver Island:

- Assuming EPA renewal of the Island Generation project and some level of DSM delivery, the transmission links between the Lower Mainland and Vancouver Island are not expected to require reinforcement within the 30-year planning horizon. BC Hydro considers the likelihood of a combined contingency conditions resulting in a need to advance transmission infrastructures in this IRP is low, therefore, BC Hydro has not reflected this risk in its CRPs.

North Coast:

- Adding three new series capacitor stations to the existing 500 kV lines from WSN to SKA and installing adequate transformation capacity and voltage support in the existing BC Hydro substations is required by F2020 to serve Expected LNG load in the region. Work needs to be advanced to maintain this in-service date. Since the proposed reinforcements are non-wire upgrades, BC Hydro considers the risk of not meeting the F2020 ISD to be low. Consequently, there is no need to develop a transmission contingency plan at this time. Higher levels of LNG load will likely require either additional transmission reinforcements or local dependable (gas-fired) generation.

Generation Clusters:

- BC Hydro concludes there are no clear net benefits for pre-building new transmission lines to access generation clusters. However, BC Hydro could evaluate building adequate transmission to the identified high potential generation cluster regions during future acquisition processes if and when projects in these regions are proposed.

Conclusions related to the mid gap and Expected LNG support Recommended Actions 8 and 13 as described in Chapter 9. Conclusions related to the transmission contingency analysis indicates the load forecast, DSM delivery and supply-related risks may require advancement of bulk transmission system reinforcements by a number of years. As a result, transmission-related contingencies are considered in the development of BC Hydro contingency plans, which are described in section 6.9; and reflected in BC Hydro's recommended CRPs and Transmission Contingency Plan, which are described in section 9.4.

6.9 Capacity and Contingency Analysis

6.9.1 Introduction

Ensuring an adequate supply of capacity is a primary concern for BC Hydro. Dependable, dispatchable capacity resources ensure system security and reliability by allowing customer loads to be met at all times throughout the year, including winter peak loads. Dispatchable capacity resources are also critical in integrating intermittent, clean or renewable generation that primarily supply energy, and may not necessarily be available during times of system need.

The need for capacity is subject to a range of uncertainties that can increase or decrease need relative to the planned level (i.e., mid gap). A smaller LRB gap than expected could result in an excess of capacity resources and pose a financial risk. BC Hydro addresses this by incorporating flexibility and off-ramps into the development process of future capacity resources. A larger than expected LRB gap poses a significant risk to reliability as it may result in a capacity shortfall either at the system level or in a specific region, and ultimately result in an inability to meet customer load. To mitigate this risk, BC Hydro plans for different contingency conditions that could result in a large gap.

BC Hydro plans the development of capacity resources considering the following conditions:

- Mid gap that leads to recommendations for the BRP
- Expected LNG load that leads to recommendations for the LNG BRP
- Contingency conditions with greater need that leads to recommendations for the CRPs with and without LNG

6.9.2 Capacity Resource Options

An inventory of resource options in B.C. is provided in Chapter 3. The resource options focused on capacity are summarized in Table 6-40. This section describes the different characteristics of capacity options and their values to BC Hydro. The key characteristics are timing/availability of capacity resources and their dispatchability.

Availability during times of need:

Capacity is most valuable if it is available at the same time as the demand for electricity, especially during times of peak load. The BC Hydro system is a winter peaking system, meaning that the integrated system demand is highest during the winter. Demand within each week is highest during weekday evenings around dinner time and second highest on weekday mornings before residential customers leave home for work. However, peak load of individual regions may occur at times that do not coincide with the integrated system peak (coincident peak).

Some capacity resource options have limited availability, being available only for a few hours per day. Examples include resources with limited storage or fuel supply, and some load curtailment products which are available only for a few hours or infrequently throughout the year. To maximize the benefits of these resources and to the extent they are available, these resources are generally used to meet demand during system peak hours (particularly weekday evenings in the winter) when the system is most capacity constrained. To the extent that more and more capacity in BC Hydro's system has limited availability, BC Hydro could find itself resource-constrained during shoulder periods that immediately precede or follow peak load hours. As a result, such resources that have limited availability are of lesser value to BC Hydro than resources that are generally available. Furthermore, potential DSM programs such as load curtailment and DSM capacity programs that aim to reduce peak demand can have unintended consequences of moving the peak to a different time as opposed to reducing overall peak demand for the system.

Given these considerations, BC Hydro must be confident that capacity resources (particularly ones that have limited availability) can reliably reduce system peak requirement before relying on them in the resource plans.

Dispatchability:

Capacity that is fully dispatchable and has a quick response time is of high value to BC Hydro as it allows generation to be varied to meet customer demand as it occurs. Examples of such resources include Site C and pumped storage. Natural gas-fired generation while being fully dispatchable has comparatively slower response times especially when it is required to start-up from a shut-down state. Dispatchable capacity also enhances the capability of integrating intermittent clean or renewable generation such as wind, and the capability of managing freshet oversupply.

Wind Integration

As discussed in section 3.4.1.4, wind power is subject to natural variations in wind speed and the amount of electricity generated is difficult to forecast. The generation is highly variable on timescales of seconds to minutes, requiring the electric system to have additional dispatchable capacity with fast response times. Dispatchable generation can ramp down its output as wind generation increases or ramp up as wind generation dies down to ensure that the net generation of the BC Hydro system can meet customer demand at all times.

Freshet oversupply

The BC Hydro system is a winter peaking system, meaning demand is highest during the winter. However, inflows into BC Hydro's reservoirs and energy from non-storage hydroelectric facilities are generally highest during the late spring/early summer freshet period (May to July), when customer demand is the lowest. As a consequence, BC Hydro's system generally has an oversupply of energy during this time that must be stored, sold to the market or spilled, even when the system is load-resource balanced for the year.

BC Hydro's oversupply period has a significant overlap with the oversupply period in the U.S. Pacific Northwest that also has large hydro resources and a freshet period. This leads to low electricity market prices in the spring. In recent years, additions of significant volumes of non-dispatchable wind generation in the U.S. Pacific Northwest region have contributed additional energy in the same spring freshet period. This additional wind energy further reduces electricity market prices in this period, driving them negative at times.

BC Hydro utilizes the storage capability and dispatch flexibility of its Heritage hydro system to store most of the energy for later use and minimize exports during the freshet period. However, this flexibility is limited and BC Hydro is forced to sell energy into the market during freshet or spill the water/energy because of an oversupply that cannot be stored. There is also a lost opportunity that results from having increased resources delivering in the freshet. Under conditions when BC Hydro is not forced to sell during the freshet, increases in freshet generation (e.g., from non dispatchable resources and resources with minimum flow requirements) erode BC Hydro's ability to purchase low priced market energy to serve customers' load while saving water/energy for sale later in higher price period. This has a negative financial impact on BC Hydro.

To avoid further negative impacts of surplus energy in the freshet, BC Hydro must take into consideration the impact of freshet period energy deliveries in any resources evaluation. The following are potential mitigation measures to the freshet oversupply/low market price concerns:

1. Reduce purchases of non-dispatchable energy during freshet periods
2. Link purchase prices of any additional energy during freshet periods to actual market prices and market availability
3. Include more dispatchable generation resources in BC Hydro's supply portfolio
4. Increase loads during freshet periods

When dispatchable capacity is combined with storage capability, it can also maximize the benefit of energy limited resources by shaping its energy production from low value time to high value time. Of lesser value is capacity that is dispatchable but requires pre-scheduling and/or long ramp times. The longer lead time diminishes value because it is less flexible to match capacity needs at specific times, requires guessing, and can come with an opportunity cost. Capacity that is non-dispatchable has the least value.

Table 6-40 shows the capacity potential, lead time, UCC and some key considerations for different capacity options. The UCC and MW shown in the table have not been adjusted to reflect the different characteristics of the options. BC Hydro examines all of these characteristics in evaluating capacity resources and making recommendations related to the development of capacity resources.

Table 6-40 Inventory of Capacity Resource Options

Resource Option	Potential (MW)	Lead Time (years) or Earliest In-Service Date	Cost at POI ($2013/kW-yr)	Reference Sections and Key Considerations
Market purchases backed by Canadian Entitlement (**CE**)	Up to 500	n/a	varies	Section 3.4.2.4 Low-cost bridging option Prescheduled capacity
Revelstoke Unit 6	500	F2021	50	Section 3.4.2.3 Low-cost long-term option, clean Dispatchable capacity with fast response time
GMS Units 1-5 Capacity Increase	220	F2021 first unit	35	
Natural Gas-fired Generation	100 (per unit)	4 – 5	>=84[44]	Section 3.4.2.2 Long-term option, but not clean Dispatchable capacity with ramp rate restrictions
Pumped Storage (Lower Mainland/Vancouver Island)	500 – 1000 (per unit)	8	>=118[45]	Section 3.4.2.1 High-cost long-term option, clean Dispatchable capacity with fast response time

Note that capacity options such as load curtailment, DSM capacity programs and Mica pumped storage have been screened out as not viable options for planning purpose at this time, as discussed in section 3.7.

6.9.3 Capacity Planning – Mid Gap

As shown in Table 6-40, the viable long-term clean capacity options available to BC Hydro are limited. BC Hydro is counting on the DSM target, EPA renewals and

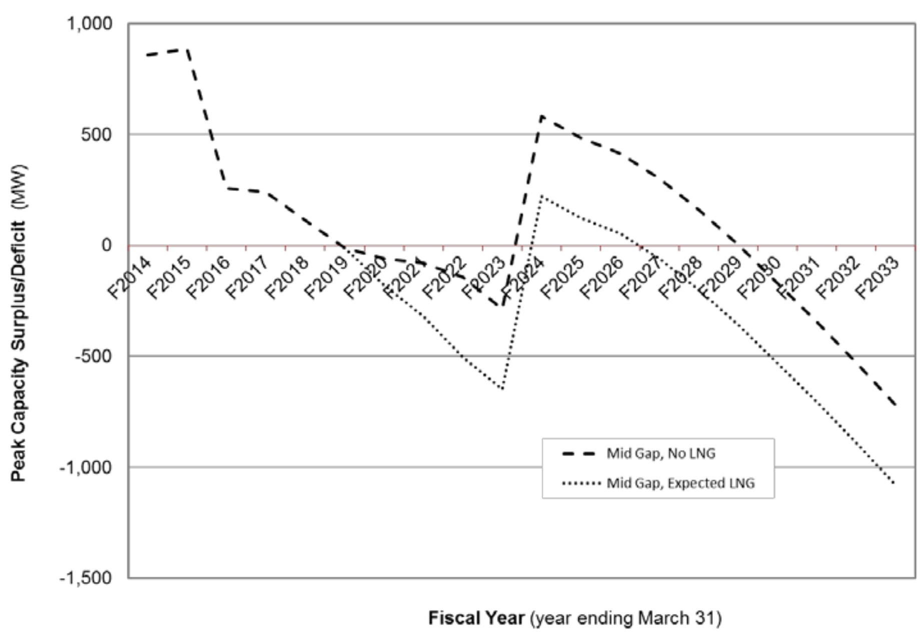
[44] The UCC shown is for a SCGT located at Kelly Lake which is in close proximity to transmission and a major gas pipeline.

[45] The UCC shown is for the lowest cost pumped storage site identified in studies on potential pumped storage sites in B.C. A pumped storage project located at another site would have a higher UCC.

Site C to contribute 1,400 MW by F2021, 539 MW by F2023 and 1,100 MW by F2024, respectively To replace the capacity contribution from any one of these resources would require BC Hydro to use up its identified low-cost Resource Smart options as well as needing non-clean options or high-cost clean options such as pumped storage.

BC Hydro developed two BRPs to meet mid gap conditions, one without Expected LNG and one with Expected LNG. The yearly forecast peak capacity requirements based on mid gap with and without Expected LNG (excluding planning reserve requirements) are shown in Figure 6-17. These lines show the capacity requirements after considering the capacity contribution from the DSM target and Site C. In each of these cases, there are two distinct periods for capacity requirements (i.e., before and after Site C).

Figure 6-17 Capacity Requirements under Mid Gap



6.9.3.1 Mid Gap without LNG

In the without LNG case shown in Figure 6-17, there is a five-year gap up to about 300 MW before Site C. Given the short-term nature of this gap, the lowest cost option to meet the capacity requirement during this time is to rely on the market, backed up by the CE provided under the Columbia River Treaty.[46] This is the lowest cost option as BC Hydro can defer building long-term B.C.-based capacity resources which would otherwise result in unnecessary surplus shortly after when Site C comes online.

As set out in section 2.3.1.4 and 3.4.2.4, market purchases and CE are not categorized as long-term resource options because BC Hydro is precluded from planning to rely on them to meet its long-term needs. However, BC Hydro is recommending reliance upon them for short-term bridging purposes. The delivery of CE capacity is more reliable than pure market purchases because the electricity and transmission to transport the CE electricity to B.C. have higher priority given it is backed by an international treaty. However, BC Hydro still estimates that in practice market purchases backed up by CE would only be available to supply BC Hydro with a maximum of 500 MW given transmission constraint through the Interstate 5 corridor during peak winter conditions when U.S. utilities have similar high-load conditions.

There are risks associated with relying on the market:

- There is uncertainty associated with the delivery of CE post-F2024. While the Columbia River Treaty has no termination date, either Canada or the U.S. can unilaterally terminate most of the provisions of the Columbia River Treaty any time after September 16, 2024, providing that at least 10 years of notice is given.

[46] Burrard would continue to be available to provide transmission support services and in the case of emergency as permitted by section 13 of the *CEA*.

- Reliance on the market for capacity is generally risky as capacity is required at specific times to meet load requirements. Planning conditions have been evolving with more intermittent resources (poor in dependable capacity) in both the B.C. system as well as in U.S. Pacific Northwest. Integration issues with intermittent resources and the tight capacity margin in the market means BC Hydro prefers to have an adequate amount of dependable generation in its service area to maintain system security and reliability.

With all of the factors considered above, BC Hydro is comfortable relying on the CE for the 300 MW gap identified before Site C as a short-term bridging resource. However, it should be noted that this option does not meet the self-sufficiency requirement; refer to section 9.2.7.

At the same time, it is noted that the two DSM capacity focused options described in section 3.3.2 are potential low cost options in B.C. They are not viable options at this time because they are subject to uncertainty with respect to their ability to reduce the system peak over the long term. Recommended Action 2 set out in Chapter 9 will allow BC Hydro to confirm savings potential from DSM capacity-focused options for two purposes: to displace market/CE bridging reliance and to confirm the reliable potential as a long-term planning resource.

6.9.3.2 Mid Gap with LNG

With Expected LNG, there is a five-year gap up to 650 MW before Site C as shown in Figure 6-17. This gap is more than double in size compared to the case without Expected LNG. In consideration of the risks associated with the market/CE bridging and DSM deliverability risk, BC Hydro is not prepared to rely upon market/CE bridging beyond the 300 MW five-year gap prior to Expected LNG. Section 6.5 provides a discussion on the capacity resources to serve the Expected LNG with a conclusion that natural gas-fired generation in the North Coast would provide valuable system flexibility and reliability value when sited in North Coast where most of the LNG developments are expected. BC Hydro should therefore explore natural gas-fired generation in the North Coast at this time so it is a feasible option when LNG load commitment is confirmed. Based on the incremental capacity requirements of 360 MW from Expected LNG considered in this IRP, four 100 MW SCGTs may be required.

6.9.4 Contingency Planning

- Contingency planning is done as a reliability management tool to manage the risk (probability and consequence) of not being able to meet load by identifying alternative sources of supply that should be available should the BRP not materialize as expected. As discussed in Chapter 4, the need for energy and capacity is subject to a range of uncertainties that can increase or decrease need relative to the planned mid gap which forms the basis for the BRP: The risk of capacity shortfall is BC Hydro's primary concern because capacity is required at specific times to meet peak load requirements and maintain system security and reliability. BC Hydro also has limited short lead time capacity options in B.C. and relying on market comes with the risks as discussed in section 6.9.3.1.

Self-sufficiency requirements aside, the risk of energy shortfall is less of a concern for BC Hydro because it is less risky to rely on the market for energy given BC Hydro system's energy shaping capability .The capacity planning concern includes both generating capacity and transmission capacity. To mitigate the capacity shortfall risks on the generation side, BC Hydro develops contingency plans to identify additional resources that should be maintained as feasible options and takes steps to reduce their lead times to ensure that these options are available if greater need results. On the transmission side, BC Hydro prepares specific CRPs that are used in the analysis of associated transmission requirements. Section 6.8 presents the results of a preliminary assessment for transmission requirements for the CRPs as well as an assessment of the need for transmission contingency plan (i.e., a plan to address key transmission shortages or delays that can impact BC Hydro's resource plans).

Within the CRPs, to manage potential energy shortfalls, BC Hydro develops a strategy to secure additional resources should the need for energy substantially exceed forecast estimates. Section 6.9.4.5 canvasses the energy shortfall in a large gap scenario while section 9.44 presents the strategy BC Hydro has in place to address a large energy gap as part of its CRP.

6.9.4.1 Uncertainties

As discussed in Chapter 4, there are a number of uncertainties and risks that BC Hydro considers in its resource planning and analysis. Table 6-41 summarizes each uncertainty in terms of its potential impact on the need for capacity, the type of indication that would let BC Hydro know that a change has occurred and the amount of warning time that BC Hydro would likely have to respond from the time of indication of a change to the requirement to provide electricity service. BC Hydro categorizes the uncertainties by three important traits:

1. Timing in which a change to the capacity requirements may occur (near-term or long-term)
2. Whether BC Hydro would have sufficient time to react to a change
3. Whether the change will happen gradually or immediately with a specific 'signpost' that indicates that there is a change in capacity requirements.

Table 6-41 Capacity Need Uncertainties

Category	Uncertainty	Potential Impact on Capacity Gap Size	Leading Indicator	No. of Years of Advance Warning
Near-Term, Possible Insufficient Reaction Time, Gradual	Load (includes Mining + Oil & Gas)	+1,050 MW in F2021	Year-by-year load growth	1-4
	DSM	+300 MW in F2021	Year-by-year load growth	1-4
Near-Term, Possible Insufficient Reaction Time, Signpost	Wind ELCC	Up to about +150 MW in F2021	Experience & Internal analysis	1-4
Near-Term, Sufficient Reaction Time, Signpost	LNG	+ 500 MW in F2021	Customer requests	4
	High Fort Nelson/HRB	+ 1,000 MW in F2021	NETL commitment	4
Long-Term, Sufficient Reaction Time, Signpost	Site C	Material delay in delivery of Site C's +1,100 MW	Approvals to proceed; ISD.	4
Long-Term, Sufficient Reaction Time, Gradual	General Electrification	Growing to +400 MW in F2021 (E3)	Gov't policy, load growth, technology	3-6

BC Hydro considers the inventory of available capacity resources in conjunction with the list of uncertainties to prioritize resource options that can be used to respond to changes in need as they happen. BC Hydro is most concerned with uncertainties in the near-term with insufficient reaction time. The key uncertainties that fall under this category are listed below and should be considered in developing contingency plans.

- Load forecast uncertainty
- DSM deliverability risk
- Effective Load Carrying Capability (**ELCC**) of clean or renewable intermittent resources

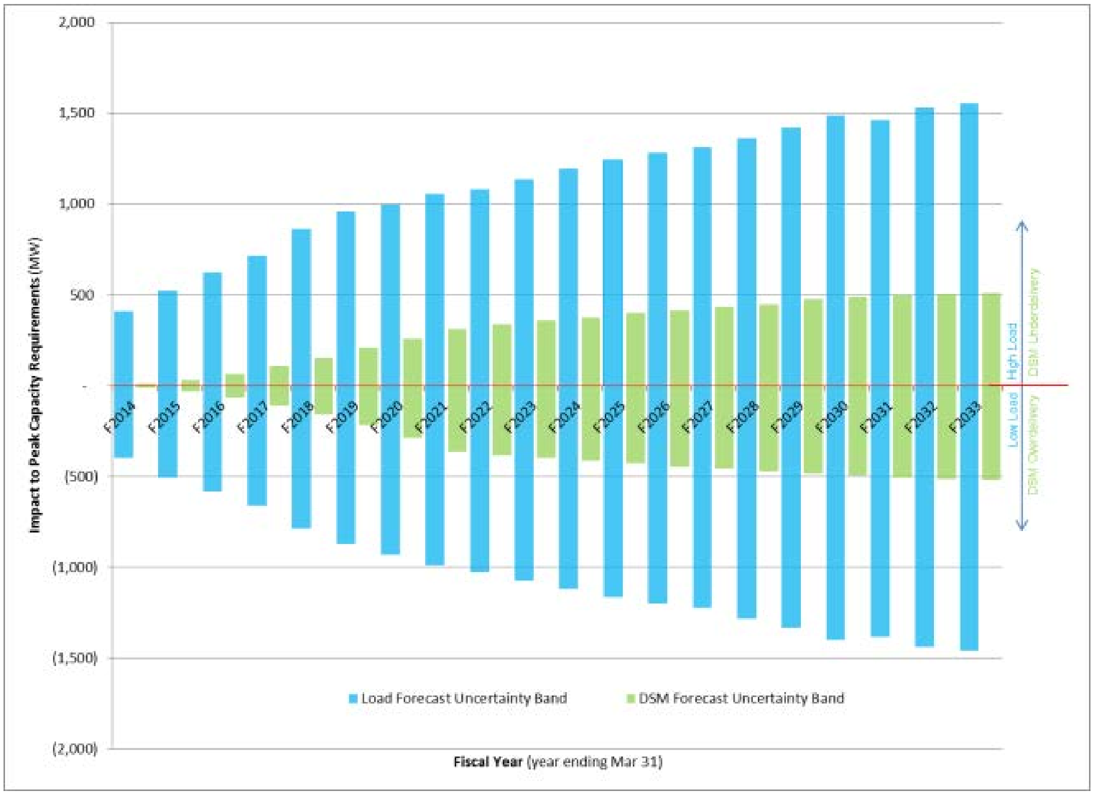
6.9.4.2 Load Forecast Uncertainty and DSM Deliverability Risk

As discussed in Chapter 4, the uncertainties from load forecast and DSM deliverability are significant. Section 2.2.4 describes the uncertainty band around the mid-load forecast. A low-load forecast (about P10) represents the expected outcome if the load is less than the twentieth percentile in each year; and the high-load forecast (about P90) represents the expected outcome if the load exceeds the eightieth percentile in each year. This uncertainty band is also reflective of the uncertainties associated with major industrial sectors including mining, oil and gas, and forestry. As shown in Figure 6-18, by F2021, the high-load forecast could be 1,050 MW higher than the mid-load forecast used for developing the BRP. This figure also shows that load forecast uncertainty is the more significant uncertainty than DSM delivery. While the uncertainty band is large, some of the new load would have warning signs (such as new load interconnection requests from the mining, and oil and gas sector) to allow BC Hydro time to react. These loads account for a substantial portion of the uncertainty band. The oil and gas sector makes up about 50 per cent of the uncertainty band in F2021 with about 70 per cent of the oil and gas sector being a new load.

Section 4.3.4.2 describes the uncertainty band around the mid level of DSM savings. The low level of savings (about P10) represents the expected outcome if the savings level is less than the twentieth percentile, whereas the high level of savings represents the expected outcome if the savings level exceeds the eightieth percentile. As shown in Figure 6-18, by F2021, the low level of savings could be 300 MW lower than the mid level used for developing the BRP.

BC Hydro has traditionally planned to the high-load forecast with a low level of DSM savings (referred to as the large gap) in developing its CRPs. As Figure 6-18 highlights, there is a substantial amount of uncertainty around the load forecast, which could be about 1,350 MW larger than expected by F2021. This underscores the importance of having adequate capacity resources ready in the near-term to respond in case demand drifts away from its expected level in the coming years.

Figure 6-18 Load and DSM Uncertainty Bands



6.9.4.3 Effective Load Carrying Capability of Intermittent Resources

As discussed in section 4.3.4.5, BC Hydro considers additional uncertainty with respect to the reliance on the ELCC of intermittent resources such as wind. Relying on intermittent resources to meet peak demand has risks.

As described in Appendix 3C, BC Hydro currently uses an assessment of ELCC for intermittent resources. The capacity contribution is calculated based upon the probability of capacity being available under peak load conditions and is currently 24 per cent of installed capacity for existing and committed wind resources. As BC Hydro gains experience in the operation of intermittent resources and as the penetration of intermittent resources grows, BC Hydro will assess the extent to which the capacity materializes and the ability to utilize the capacity on an operational basis. Wind generation causes particular concerns due both to its high degree of short-term variability and the experience of neighbouring jurisdictions of having little wind available during peak load circumstances. BC Hydro currently relies on approximately 150 MW from existing wind EPAs. If studies or operational experience were to reduce the 24 per cent ELCC, BC Hydro would need to acquire additional capacity.

Given BC Hydro's current capacity reliance on wind resources is small, the range of uncertainty captured by load forecast and DSM delivery uncertainties is considered sufficient to cover this additional uncertainty for the purpose of contingency planning. BC Hydro will continue to monitor the capacity contribution from its intermittent resources and make adjustments as more operational experience is available.

6.9.4.4 Large Gap for Capacity

Figure 6-19 shows the large capacity gap with and without Expected LNG assuming high-load and low DSM uncertainties. The large capacity gap without Expected LNG shows need starting in the first planning year, F2017, and growing to 1,800 MW before Site C's earliest ISD in F2024. To meet the potential earlier need and significant capacity requirement, resource options with short lead time and significant potential will need to be considered.

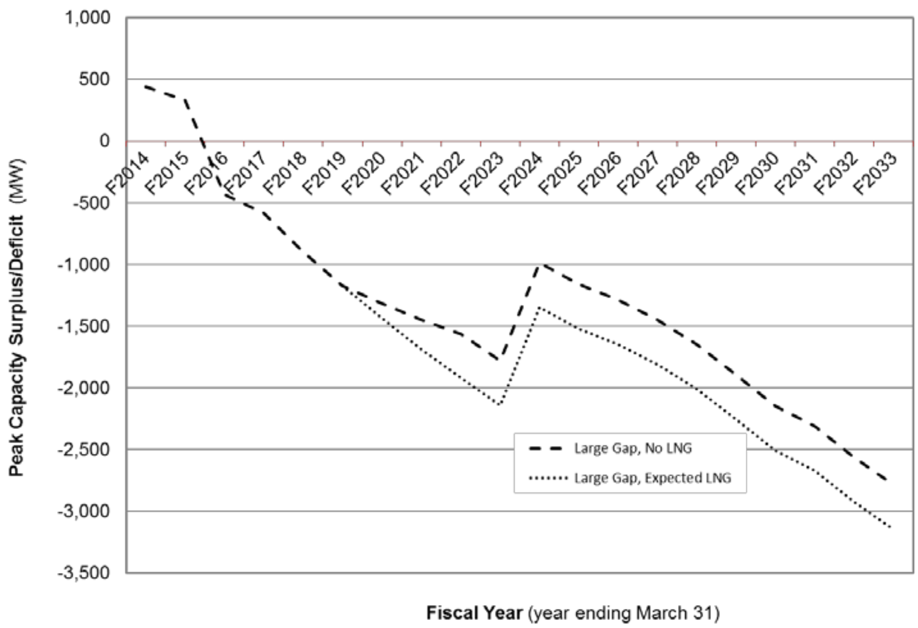
As described in Chapter 3, the remaining large and cost-effective Resource Smart projects are Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase. As shown in Table 6-40, these projects are relatively low-cost and long-term capacity options. They also provide high-value dispatchable capacity. However, they are not available until F2021 for Revelstoke Unit 6 and F2021 for GMS Units 1-5 Capacity Increase (first unit). In addition, GMS Units 1-5 Capacity Increase would be limited to one unit (about 40 MW) being upgraded per year. During this process, the unit being upgraded would likely required to be out of service, thus reducing the supply by 270 MW.

As described in section 6.2, natural gas-fired generation has special value as a transmission alternative and for contingency conditions. The short lead time to build natural gas-fired generation (once permits are secured) makes it an ideal contingency resource.

Given the above considerations, BC Hydro should advance the two Resource Smart options, and natural gas-fired generation options to have the flexibility to choose the more cost-effective option or combination of options should a larger gap materialize. To strike a balance between preparing for contingency conditions and incurring unnecessary costs, BC Hydro should continue to advance these options through identification and early definition phase activities such as regulatory approval processes, but avoid committing significant capital before need is confirmed.

The large capacity gap with Expected LNG, shown in Figure 6-19, indicates a capacity need growing to 2,100 MW before Site C's F2024 ISD. Based on the larger gap size and the flexibility to serve LNG with natural gas-fired generation, BC Hydro would consider using additional natural gas-fired generation to meet the incremental capacity need for LNG.

Figure 6-19 Large Gap Capacity Requirements

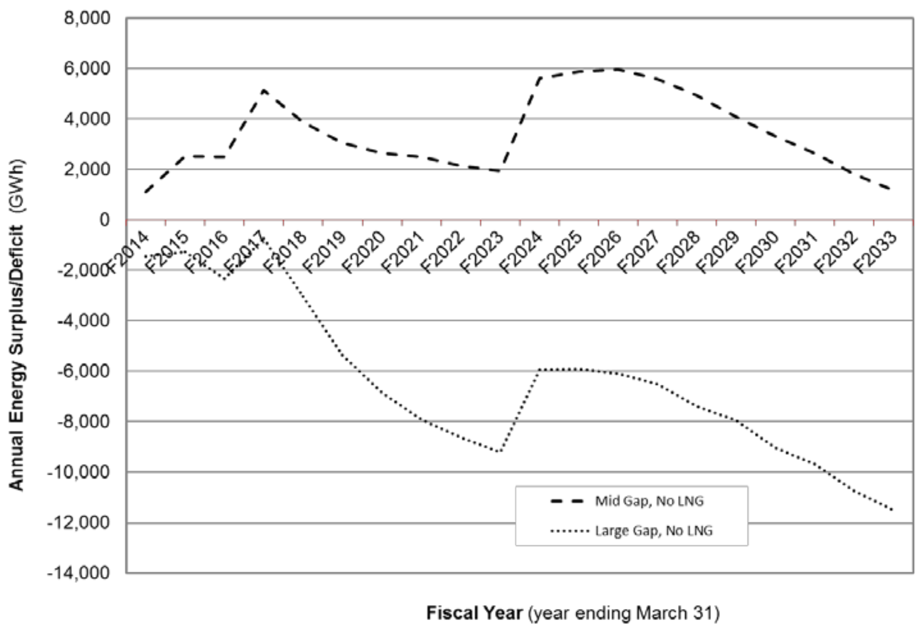


6.9.4.5 Large Gap for Energy

Figure 6-20 shows both the mid and the large gap for energy. As this figure shows, under expected conditions with EPA renewals, the DSM target and Site C as part of the BRP, there will be surplus energy beyond the 20-year planning horizon. However, as described above, the expected forecast need for energy is subject to uncertainties including:

- DSM delivery uncertainty
- Load growth uncertainty, in particular, the rapid growth in mining and the oil and gas sectors

Figure 6-20 Mid and Large Gap for Energy Requirements (No LNG)



Pairing the high-load growth scenario with the low DSM delivery scenario yields the large gap scenario, which has roughly a one in ten chance of occurring or being exceeded. In the large gap scenario, a need for energy emerges in F2017 and grows to roughly 9,200 GWh/year by F2023. It is expected that some of this need will be met by energy associated with the contingency capacity resources, as discussed in section 6.9.

While growth in energy demand above the expected level does not require BC Hydro to have shelf-ready contingency plans as it does for capacity, the legislated self-sufficiency requirements and prudent utility practice do require that BC Hydro has a strategy in place to respond to higher than expected load growth. Section 9.4.5 specifies the volume and timing of clean energy required in a large gap scenario (see Figure 9-7 for details), and Recommended Action 10 in Chapter 9 details the preparatory steps, key signposts and triggers that BC Hydro anticipates would lead to additional clean energy procurement.

6.9.5 Conclusions

The capacity and contingency analysis has shown the following:

- Site C and capacity savings associated with EPA renewals and DSM target are required to serve the mid gap. There remains a capacity gap before Site C in both the with and without LNG cases
- For the BRP prior to Expected LNG, market purchases backed up by the CE serving as bridging capacity until Site C is in-service is the most cost-effective option. The gap is small and short-lived. This option does not meet the self-sufficiency requirement and would require B.C. Government approval. The two DSM capacity-focused options are potential low-cost options and efforts to confirm savings potential should be undertaken and have the ability to displace bridging capacity and be included in future resource planning assessments.
- For the BRP with Expected LNG, BC Hydro should consider natural gas-fired generation in the North Coast given incremental capacity needs before Site C, transmission benefits related to facilitating maintenance outages, and increased voltage stability
- In light of significant planning uncertainties such as those related to load forecast and DSM deliverability, BC Hydro should pursue the following options to have the flexibility to choose the more cost-effective option or combination of options should a larger gap materialize
  - ▶ Advance Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase through low-cost investigation and definition phase activities to maintain their earliest ISDs
  - ▶ Advance natural gas-fired generation to reduce its in-service lead time associated with the potentially long siting and approval process. Locations considered for siting natural gas-fired generation as contingency resource include the North Coast, Kelly Lake, and Vancouver Island

Conclusions in this section support Recommended Actions 2, 7, 10, 11, 15, 16 and 17 as described in Chapter 9.

6.10 Differential Rate Impact

The IRP analysis is consistent with BCUC findings on project evaluation methodology contained in the BCUC's decision concerning BC Hydro's 2006 IEP/LTAP. Specifically, the BCUC found the key economic evaluation criteria to be PV and levelized cost analysis (e.g., UEC). The BCUC found that the economic evaluation criteria is the primary test, and that the ratepayer impact analysis is a less material, secondary test since rate impacts should reasonably be correlated with the economic analysis[47] (i.e., projects with higher portfolio PVs will be indicative of the need for higher rate requirements, and lower PVs will be indicative of the need for lower rate requirements). There can be an exception to this correlation for DSM which is discussed later in this section.

Consistent with the BCUC findings, BC Hydro bases its portfolio economic analysis on PV calculations. The PV and UEC analysis informs BC Hydro's Recommended Actions in Chapter 9.

Differential rate impact between portfolios is provided for information purposes. The rate impact analysis is relative; that is, it compares the rate impacts between the different incremental resource options considered in the IRP to meet the identified need. Relative rate impact analysis is what BC Hydro typically provides to the BCUC in project CPCN applications.[48] Both the PV costs and the differential rate information provided in this IRP exclude the costs that are common to all portfolios because they are irrelevant in comparing incremental resource options.

[47] 2006 IEP/LTAP Decision, pages 200-201.

[48] For example, most recently in section 4.6 of BC Hydro's Application for a Certificate of Public Convenience and Necessity for the John Hart Generating Station Replacement Project.

The analysis presented in this chapter does not assume any regulatory account treatment or rate smoothing mechanisms as a project or asset comes into service. This is a major assumption particularly for large capital projects such as Site C and Revelstoke Unit 6. The actual timing and method of cost recovery from rates is subject to BCUC approval and is likely to differ from this analysis. Hence, compared to PV analysis, the differential rate analysis is subject to additional significant uncertainty regarding the timing and method of recovery of costs from rates.

6.10.1 Approach and Assumptions

The differential rate impact analysis is based on the base set of resource portfolios contained in this IRP. The differential rate impact presented generally reflects the difference in annual costs (e.g., cost of energy and revenue from trading energy from the BC Hydro system) between the portfolios based on the assumed timing of cost recovery from rates. For projects developed by BC Hydro (e.g., Site C, Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and transmission projects), a traditional regulatory treatment of a BC Hydro capital asset without any regulatory account treatment or rate smoothing mechanism is assumed as follows:

- Recovery of costs through customer rates begins once the project commences commercial operations
- Costs related to capital expenditures of the asset/project consist of:
  - Depreciation (i.e., amortization) of the project capital expenditures which would occur over a period as determined by accounting principles and accepted by the BCUC
  - Financing costs (i.e., interest on debt associated with the project) based on the BC Hydro long-term cost of debt forecast
  - An incremental return on equity on the capital invested in the project, based on the allowed return on deemed equity set forth in Heritage Special Direction No. HC2 to the BCUC

  - Operating charges, including operations and maintenance expenses, and water rentals

- DSM expenditures are amortized over 15 years.

To mirror the key portfolio PV analysis conducted in the IRP, four sets of differential rate comparisons are presented. They are: (1) Clean Generation portfolios without LNG load; (2) Clean and Thermal Generation portfolios without LNG load; (3) Clean Generation portfolios with Expected LNG load; and (4) Clean and Thermal Generation portfolios with Expected LNG load.

6.10.2 Results and Observations

Figure 6-21 to Figure 6-24 compare the rate impact of key portfolios against a base case portfolio with Option 2/DSM Target and Site C at its earliest ISD of F2024[49]. The key resource choices compared between the portfolios are different levels of DSM (i.e., Option 2/DSM Target versus DSM Option 3 and DSM Option 1), Site C and their alternative resources (including IPP resources in the Clean Generation or Clean + Thermal Generation portfolios and BC Hydro projects such as Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase).

The effect of DSM on rates is unique in the sense that is not always one-directional. For example, the costs of supply-side resources increase the BC Hydro revenue requirement, and accordingly the rates increase. DSM, on the other hand, typically decreases the revenue requirement (or aggregate customer bill) relative to a supply-side only portfolio because DSM avoids new supply-side resources which are typically higher cost. However, the revenue requirement must be collected from a reduced energy sales base. Depending on the net effect, DSM could have the effect of increasing or decreasing relative future rates despite the fact that it would reduce the relative revenue requirement or portfolio PV.

[49] As described in section 6.1, all portfolios analyzed in this IRP reflect the cost management approach (including EPA renewals) described in Chapter 4.

Site C is a large and capital intensive project with low operating costs. The PV analysis shows Site C to be cost-effective compared to portfolios of alternative resources. Given its large up-front capital cost, Site C is expected to increase rates for a short period when it first comes in service but will result in lower rates compared to alternative portfolios over the long term. Figure 6-21 and Figure 6-22 compare key portfolios with no LNG load. Given Option 2/DSM Target, the Site C F2024 ISD portfolio is shown to have rate savings compared to the no Site C portfolio starting around F2030 (i.e., about 6 years into its economic life of 70 years and physical life of over 100 years) for the Clean Generation portfolio and around F2033 for the Clean + Thermal Generation portfolio.

Figure 6-21 also compares different levels of DSM. In both the with and without Site C scenarios, DSM Option 3 generally results in a higher rate impact relative to the corresponding Option 2/DSM Target scenario.

By comparing the DSM Option 3 without Site C case to the Option 2/DSM Target with Site C base case, there is again a trade-off between mid-term and long-term rate impact as in all portfolio comparisons with and without Site C. The Site C with Option 2/DSM Target portfolio is shown to have rate savings compared to the no Site C with DSM Option 3 portfolio starting around F2029 (about a year earlier than the Option 2/DSM Target scenario discussed above).

In contrast, a lower level of DSM (i.e., DSM Option 1) has a lower rate impact than Option 2/DSM Target in the near term. Given Site C, DSM Option 1 has rate savings in the mid term and starts having a larger rate impact than Option 2/DSM Target around F2032. The mid-term savings is a result of reduced energy surplus in the early years of Site C whereas the larger rate impact in the longer term is due to the cost incurred from higher cost supply-side resources needed to make up the shortfall of savings in DSM Option 1 relative to Option 2/DSM Target.

As discussed in the earlier sections of Chapter 6, portfolios with Option 2/DSM Target and Site C yield the lowest PV. In choosing these resource options, the IRP is consistent with BCUC direction that economic evaluation is the primary test, notwithstanding that there may be trade-offs between potential impact on near-term and long-term rates, and revenue requirements (in the case of DSM).

Figure 6-21 Differential Rate Impact for Clean Generation Portfolios without Expected LNG

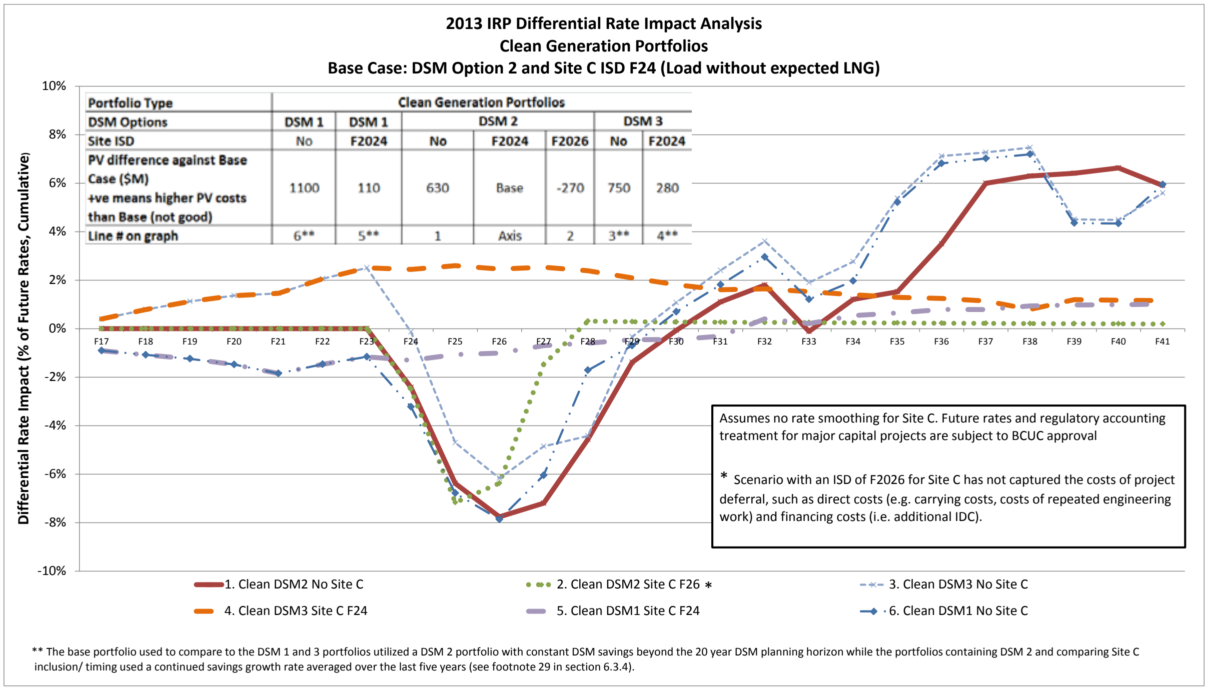


Figure 6-22 Differential Rate Impact for Clean and Thermal Generation Portfolios without Expected LNG

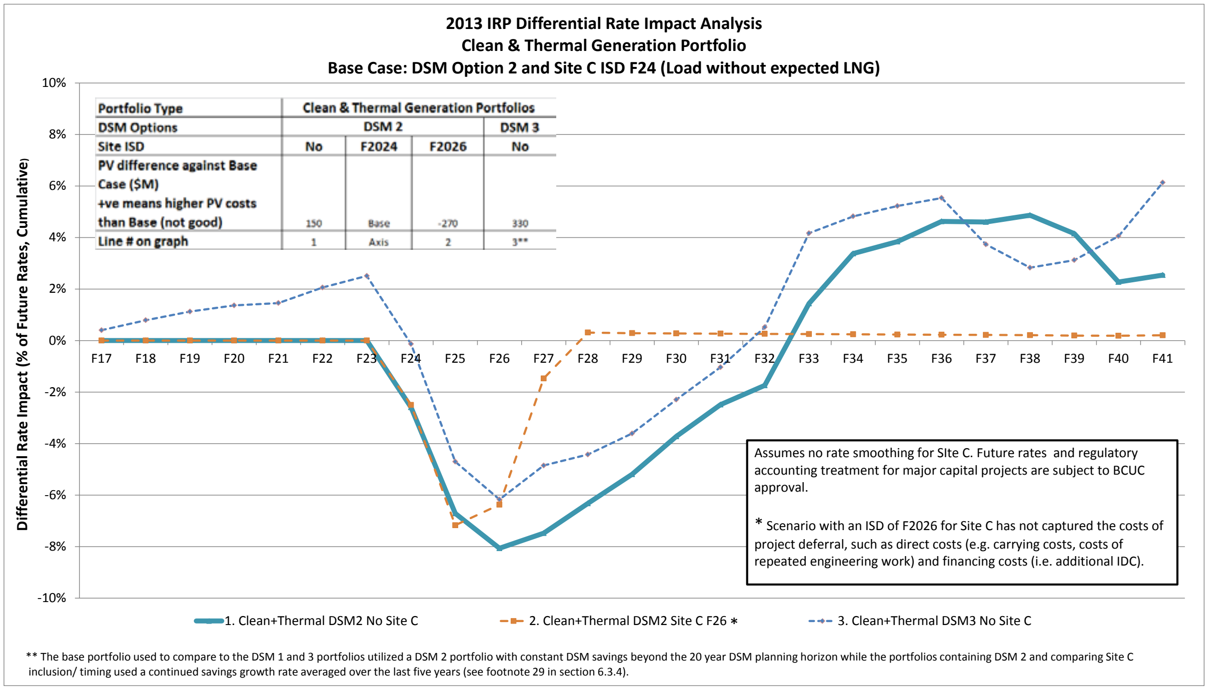


Figure 6-23 and Figure 6-24 compare key portfolios with Expected LNG, with Figure 6-23 comparing the Clean Generation portfolios and Figure 6-24 comparing the Clean and Thermal Generation portfolios.

By comparing Figure 6-21 and Figure 6-23 with Figure 6-22 and Figure 6-24, the key observation is that the Expected LNG load could reduce the maximum and shorten the duration of rate impact from Site C in the early years because the energy surplus associated with the project in its early years is now used to meet the LNG load that yields higher revenue than market sale.

Figure 6-23 Differential Rate Impact for Clean Generation Portfolios with Expected LNG

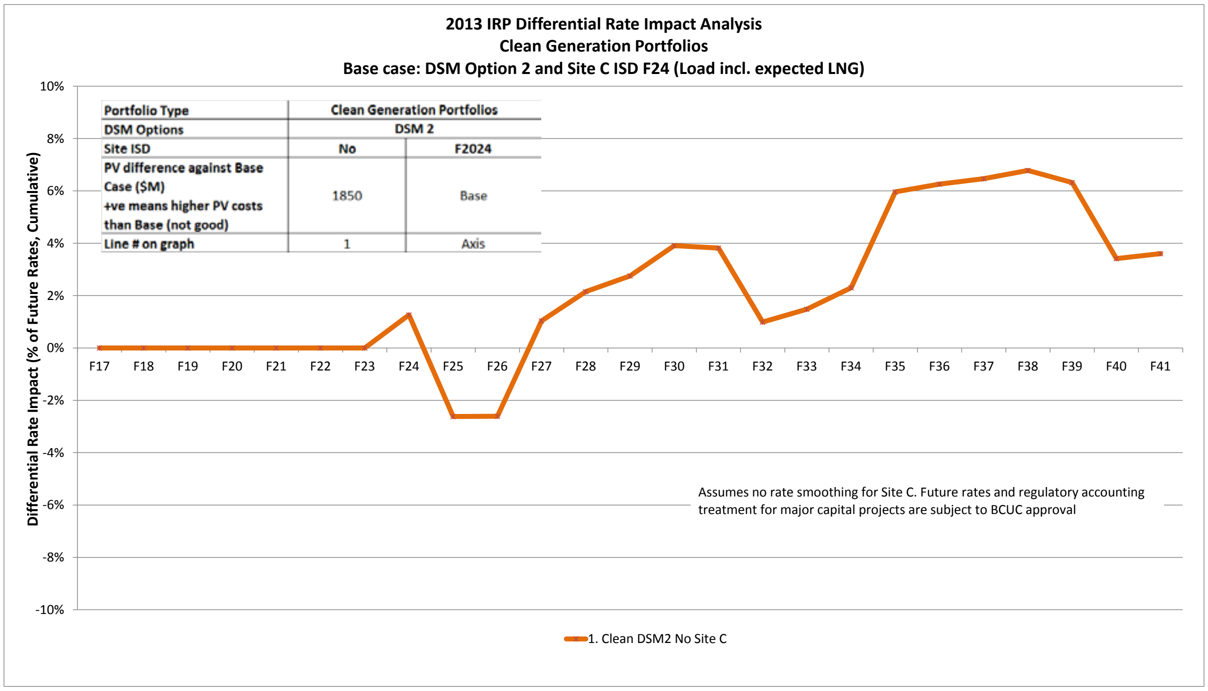


Figure 6-24 Differential Rate Impact for Clean Generation Portfolios with Expected LNG