5 NEED FOR, PURPOSE OF, AND ALTERNATIVES TO THE PROJECT

5.1 Introduction

This section describes the need for, purpose of, and alternatives to the Project. The "need for" establishes the fundamental justification or rationale for the Project. The "purpose of" is defined as what is to be achieved by carrying out the Project. The "alternatives to" are the functionally different ways to meet the Project need. The alternative means of carrying out the Project are considered in Volume 1 Section 6 Alternative Means of Carrying Out the Project.

The definitions of "need for", "purpose of" and "alternatives to", and the following discussions, are consistent with the Agency's "Policy Statement – Addressing the Need for, Purpose of, Alternatives to and Alternative Means under the Canadian Environmental Assessment Act" (Agency Need/Alternatives Operational Policy Statement). In particular, the need for and the purpose of the Project are established from the perspective of BC Hydro and provide the context for consideration of alternatives.

This section reviews both demand side management (DSM) and supply-side resources in the context of both need for and alternatives to the Project:

- The need for the Project is established using two reliability requirements – firm energy and dependable capacity:
  - Energy is the amount of electricity required over a period of time, measured in gigawatt hours per year (GWh/year)
  - Peak demand, which is the maximum hourly demand on BC Hydro's system, is measured in megawatts (MW) and is met with dependable capacity. Securing dependable capacity resources to address future dependable capacity needs described in this section is becoming more of a challenge.
  - Over the last seven years, BC Hydro purchased large quantities of intermittent clean or renewable energy resources such as run-of-river and wind that have minimal dependable capacity. Intermittent resources are not dispatchable – that is, their electricity output cannot be controlled to respond to variations in customer demand. Intermittent clean or renewable resources require dependable capacity backup resources.
  - To address growth in the demand for dependable capacity in recent years, BC Hydro has benefited from being able to install additional generating units at each of its two Heritage hydroelectric facilities (Mica and Revelstoke Generating Stations). With one of these generating units now in operation (Revelstoke Unit 5), two more under construction (Mica Units 5 and 6) and the fourth (Revelstoke Unit 6) included in this EIS with an earliest in-service date of F2019, these additional capacity resources will be exhausted. (All year marks in this section are stated in fiscal years (F20XX) ending March 31, except where otherwise noted.) There are limited dependable capacity resource options available to BC Hydro after implementation of Revelstoke Unit 6, and this is

compounded by increased system reliance on non-dispatchable intermittent clean or renewable energy resources.

- There are two broad categories of potential alternatives to the Project. Demand-side management consists of measures – such as conserving energy, promoting energy efficiency, and shifting the use of energy to periods of lower demand – that BC Hydro can take to reduce the customer demand that BC Hydro must serve. Supply-side resources are electricity generating facility resources that are consistent with the objectives of the B.C. Government, including those specified in the B.C. *Clean Energy Act* (S.B.C., 2010, c.22).

The remainder of this section is structured as follows:

- Section 5.2 sets out the need for the Project. The Project addresses BC Hydro's need for firm energy and dependable capacity within the context of meeting the self-sufficiency requirement set out in Subsection 6(2)(a) of the *Clean Energy Act*. To determine the need for the Project, BC Hydro's energy and capacity load-resource balances (LRBs) are analyzed for the BC Hydro integrated system, taking into account the current level of DSM targeted by BC Hydro. The result is a gap that must be filled with supply-side resources.
- Section 5.3 outlines the purpose of the Project. In addition to meeting BC Hydro's need for firm energy and dependable capacity, the Project advances and aligns with the B.C. Government's objectives set out in the *Clean Energy Act* and in its 2007 Energy Plan (provided in Volume 1 Appendix D Need for and Alternatives to the Project Supporting Documentation, Part 1).
- Sections 5.4 and 5.5 examine the potential alternatives to the Project:
    - Section 5.4 describes the process for identifying and reviewing potential alternatives to the Project. Section 5.4 also surveys the potential alternatives that were screened out on the basis that they are not viable (defined as meaning not practicable or not capable of being implemented) because 1) in the case of certain supply-side resources, they are not permitted by or are inconsistent with B.C. Government legal requirements, or are not technically or economically feasible, and 2) in the case of increased DSM levels, cannot reasonably be relied on because of delivery risk.
    - Section 5.5 characterizes the remaining available supply-side resources which, when combined into portfolios, are viable alternatives to the Project. Section 5.5.1 describes the major financial, technical, environmental, and economic development attributes applied to the available supply-side resources. Section 5.5.2 presents a qualitative assessment of the available supply-side resources. Section 5.5.3 sets out the portfolio analysis parameters, while Section 5.5.4 compares the available supply-side resources through portfolio and other analysis. In Section 5.5.5, BC Hydro concludes that the Project is the preferred alternative to meet the need identified in Section 5.2, based on the review of the financial, technical, environmental, and economic development attributes, and taking into account B.C. Government legal and policy requirements.

5.2 Need for the Project

The Environmental Impact Statement (EIS) Guidelines provide that the EIS will set out the fundamental rationale for proceeding with the development of the Project at this time within the relevant legal and policy context. The need for the Project is to address future customer demand (sometimes referred to as load in this EIS; load and demand are used interchangeably) for firm energy and dependable capacity in BC Hydro's service area. The Project would provide long-term generation services for more than 100 years.

This section of the EIS contains a description of methodologies, assumptions, and conclusions used in the need for the Project analysis through an evaluation of the following:

- Current and forecasted BC Hydro customer demand
- Existing and committed supply-side resources
- The BC Hydro demand-side management target

To begin this discussion, it is important to underscore BC Hydro's obligation to serve its customers in accordance with standards established by the British Columbia Utilities Commission (BCUC) pursuant to a number of sections in the B.C. *Utilities Commission Act* (R.S.B.C., 1996, c.473), including Sections 25, 28, 29, and 30. This service obligation drives BC Hydro's long-term resource planning process. The long-term view is required, as most new resources require significant lead times to obtain approvals and build. All electric utilities like BC Hydro must plan ahead to be sure that the required resources will be in place when needed by customers. As a business planning tool, BC Hydro's long-term resource planning process supports informed decision-making on resource acquisition by providing an analytical framework for assessing resource investment trade-offs:

- The first step in the analytical framework is for BC Hydro to forecast its future electricity demand requirements. As with any potential resource available to BC Hydro, energy and capacity LRBs are analyzed for the BC Hydro integrated system to determine the need for the Project's generating capability. A load-resource balance is the difference between BC Hydro's Load Forecast – which projects BC Hydro customer load over a 20-year period – and the supply from existing and committed resources. There is a gap if forecasted customer load exceeds the supply available to serve such load.
- The analytical framework is then used to evaluate different solutions for filling the load-resource gap. BC Hydro employs this analytical framework in this section to assess the Project and potential alternatives.

BC Hydro continues to face considerable uncertainty in its long-term resource planning environment, including:

- Load growth and the risk that load growth exceeds or falls below expectations
- DSM delivery risk – the risk that the response to DSM is less than planned or required
- Supply-side development uncertainty, including the type and location of resources supplied to BC Hydro, and the risk that the type and location of resources require

significant dependable capacity (for example, for intermittent clean or renewable resources such as wind) and transmission support

These uncertainties and the +20-year planning time frame underscore the need to de-emphasize single point estimates for forecasting load and the load-resource balance; rather, uncertainties with load forecasting and the capabilities of existing supply-side resources and DSM can be translated into a range of future resource requirements. The key uncertainties in load growth and resource delivery are discussed in Section 5.2.3.

The remainder of this section is organized as follows:

- Section 5.2.1 reviews the assumptions underlying the two inputs to the energy and capacity LRBs: 1) BC Hydro's most recent (2012) Load Forecast, and 2) BC Hydro's existing and committed resources. In addition, the legal requirement for BC Hydro to achieve electricity self-sufficiency by 2016 and each year after, pursuant to Subsection 6(2)(a) of the *Clean Energy Act* is explained.
- In Section 5.2.2, the resulting energy and capacity LRBs are provided. First, the LRBs are shown without the current BC Hydro DSM target. Second, the LRBs are depicted with the DSM target and Revelstoke Unit 6, as this is a project that BC Hydro proposes to undertake in advance of the Project, due to the need for dependable capacity. It is this second set of LRBs that provides the basis for demonstrating the need for the Project and sets the context for potential alternatives to the Project. BC Hydro summarizes some loads and LRBs with respect to the following years: F2017, F2022, F2026, and F2031. All values shown include electricity losses from the transmission and distribution systems, unless otherwise stated.
- Section 5.2.3 summarizes the risks and uncertainties with respect to the LRBs, focusing on the Load Forecast and delivery of anticipated DSM savings. Some of these – such as potential large and uncertain loads from liquefied natural gas (LNG) and mining, or lower than anticipated levels of DSM savings – would result in a larger LRB gap, while others, such as lower commodity prices, would result in a smaller LRB gap. Section 5.2.3 also describes BC Hydro's Contingency Resource Plan to address dependable capacity shortfall risks.
- Section 5.2.4 contains BC Hydro's conclusions with respect to the need for the Project

5.2.1 Load-Resource Balance Assumptions

This section explores the energy and capacity LRBs by first reviewing the 2012 Load Forecast in Section 5.2.1.1, and then examining existing and committed resources in Section 5.2.1.2. The resulting energy and capacity LRBs are presented in Section 5.2.2. Throughout Section 5.2 and Section 5.3, capacity MW values have been rounded to the nearest 50 MW and energy GWh values have been rounded to the nearest 100 GWh.

5.2.1.1 BC Hydro's 2012 Load Forecast

Load is the amount of electricity required by a BC Hydro customer or group of customers. This section presents BC Hydro's 2012 Load Forecast of energy and peak (capacity) load requirements for the BC Hydro integrated system. Some of BC Hydro's customers live in areas too remote to be served by the integrated system. Local

generation serves these non-integrated communities. Unless otherwise indicated, this EIS does not address the non-integrated areas.

On an annual basis, BC Hydro prepares 20-year load forecasts for both energy and peak demand. The energy forecast represents the forecasted total annual electricity demand for the integrated system and the peak forecast represents the one-hour maximum demand on the integrated system.

The 2012 Load Forecast has been prepared in accordance with the BCUC's Resource Planning Guidelines (copy in Volume 1 Appendix D Need for and Alternatives to the Project Supporting Documentation, Part 2), using the same methodological approach for the mid-forecast accepted by the BCUC in long-term resource plan proceedings, including a sector-by-sector analysis of load. The 2012 Load Forecast incorporates the most current third-party economic indicators available to be incorporated, including gross domestic product (GDP) forecasts from the B.C. Ministry of Finance, external economic consultants and customer-by-customer information included in the industrial customer forecast.

Use of Mid-Load Forecast

The values discussed in this EIS reflect BC Hydro's mid-load forecast for both energy and peak demand. The mid-load forecast represents the expected future load, in which actual realized loads will be higher than forecast 50% of the time, and lower than forecast 50% of the time. The EIS is based on BC Hydro's mid-load forecast because:

- The B.C. *Electricity Self-Sufficiency Regulation* (B.C. Reg. 315/2010) enacted under the *Clean Energy Act* prescribes the mid-load forecast as the forecast to be used for the purpose of determining the self-sufficiency requirement
- The mid-load forecast is the forecast that BC Hydro uses to determine the need for capital projects, both internally and in applications to the BCUC. The BCUC endorsed the use of the mid-load forecast for purposes of determining need in its 2008 Long-Term Acquisition Plan Decision (BCUC Order G-91-09, Reasons for Decision, page 54 and Directive 6).
- Use of the mid-load forecast is consistent with other public electric utilities

Liquefied Natural Gas Load

The 2012 mid-load forecast presented in this section <u>does not</u> include potential LNG load, which is discussed in Section 5.2.3.

Energy and Peak (Capacity) Load Forecasts

The 2012 Load Forecast reflects the impact of savings from DSM (i.e., energy efficiency and conservation) initiatives achieved through F2012, but does not include future targeted savings in F2013 and beyond. DSM targeted savings for F2013 and beyond are described in Section 5.2.2.2. Table 5.1 and Table 5.2 present the 2012 Load Forecast energy and peak demand requirements before anticipated DSM savings (resulting from DSM initiatives after F2012) without potential LNG load.

Table 5.1 Mid-Energy Load Forecast Before DSM

(GWh)	F2017	F2022	F2026	F2031	Average Annual Growth Rate	
					F2012–22	F2012–31
Mid-energy Load Forecast (No LNG)	63,200	70,800	73,800	78,400	2.2%	1.7%

Table 5.2 Mid-Peak Demand Load Forecast Before DSM

(MW)	F2017	F2022	F2026	F2031	Average Annual Growth Rate	
					F2012–22	F2012–31
Mid-peak Load Forecast (No LNG)	11,700	12,750	13,450	14,500	2.1%	1.8%

Energy Load Forecast Components and Drivers

The three main components of the energy load forecast, each of which has its own primary drivers, are as follows. (Note that other small categories of load not included in residential, commercial, or industrial – such as sales to other electric utilities such as FortisBC Inc. – provide the balance of the total load forecast.)

Residential: BC Hydro's residential sector currently consumes about 35% of BC Hydro's total sales. Sales to the residential sector are weather sensitive, primarily to winter heating demand, and can fluctuate significantly year to year. The drivers of the residential forecast are the average annual use of electricity per account and the number of accounts, which is driven by population growth and housing starts. The average use per account is developed using an end use model that includes economic drivers such as disposable income, people per account, and efficiency trends for the primary residential end uses of electricity.

BC Hydro's long-term forecast of housing starts is expected to be on average about 26,000 units per year, a reduction over pre-recession levels. In addition, trends in residential electricity use per account have been slowing. This is due to several factors that include recent slower economic growth, the effects of conservation, BC Hydro's electricity rate changes, and an increasingly efficient appliance fleet. The average use per account is expected to grow slowly at less than 1% per year. This reflects a number of factors, including housing sizes and types, the demand for electronic, entertainment, and telecommunication devices in the home, and general improvements in the energy efficiency of major electrical appliances. With the current forecasts of housing starts and residential end use rate, the overall sales to the residential sector before DSM are expected to grow by about 1.8%, 2.0%, and 1.9% over the next five, 10, and 20 years, respectively.

Commercial: BC Hydro's commercial sector currently consumes about 31% of its total sales. The electricity consumption of the commercial sector can vary considerably from year to year, reflecting the level of activity in B.C.'s service sector. The commercial sector is made up of two categories: commercial distribution (94% of the total commercial sales) and commercial transmission (6% of total commercial sales).

The forecast of commercial distribution sales is developed with an end use model. The drivers of the forecast include average commercial end use efficiencies trends and projections of retail sales, employment, and commercial output. Sales to the commercial distribution sector before DSM are expected to grow by about 2.0%, 1.9%, and 1.8% over the next five, 10, and 20 years, respectively. This growth reflects relatively stable provincial economic growth and no significant changes in average commercial end use efficiency. The overall commercial distribution load has been revised downwards since the onset of the recent recession, consistent with the lower projections of economic drivers. Slower economic growth projections for the U.S. and global economies impact tourism and retail spending in B.C. Sales to larger commercial customers such as ports and pipelines are projected to grow over the first five years of the forecast; after these expansions are completed, commercial sales are expected to remain relatively stable.

Industrial: BC Hydro's industrial sector currently represents about 32% of its total sales. The industrial sector is made up of customers served at distribution voltages (20% of total industrial sales) and those served at transmission voltages (80% of total industrial sales, at voltage of over 69 kilovolts). BC Hydro prepares its industrial transmission load forecast on a customer-by-customer basis, considering the sector-specific issues that customers in each sector face. A projection for industrial distribution sales is developed for key sectors, including forestry (including pulp and paper), mining (coal), and oil and gas. The remaining industrial distribution sales are developed using an econometric model and provincial GDP growth as a load driver.

Industrial demand has been the most variable historically, and it is the most challenging to forecast due to sensitivity to factors such as global commodity markets and economic conditions in the U.S. and Asia. Excluding LNG, the industrial sub-sectors include the following:

1. Forestry (pulp and paper, and wood products): Historically, this has been the largest industrial sector in terms of electricity sales, accounting for about 60% on average of total industrial sales. With external experts, BC Hydro prepares a market analysis and a production outlook for each of BC Hydro's pulp and paper and wood products customers. This includes production forecasts for the key commodities that the facilities produce such as pulp, various paper grades, and various wood products. A market analysis of Asian and U.S. demand and the status of the mountain pine beetle effects on wood supply are also reflected in the forecast. Sales to the forestry sector before DSM are expected to shrink by about 2.4%, 1.2%, and 0.6% over the next five, 10, and 20 years, respectively. This reflects lower mechanical pulp and related paper production forecast, attrition in some sawmills due to the wood supply situation, and the continuing trend to digital media substitution away from print media.

2. Oil and Gas: Currently, oil and gas sales are less than 10% of total industrial sales, but this is expected to increase. BC Hydro prepares natural gas production forecasts for the key B.C. production basins based on a variety of expert forecasts. BC Hydro also uses the B.C. Oil and Gas Commission's production and drilling information to monitor natural gas historical production and possible future trends. Deferred drilling and natural gas processing due to current low natural gas prices have reduced expected growth in sales in the near term. Preferential drilling for higher value oil and liquids, and potential growth in B.C.'s supply of LNG to Asian markets are the key drivers of future load growth. The province is seen to have substantial gas development potential, particularly in the Montney (Dawson Creek to Chetwynd)

region. Sales to the oil and gas sector before DSM are expected to grow by about 19.0%, 14.3%, and 7.5% over the next five, 10, and 20 years, respectively.

3. Mining: The mining forecast is developed on an account-by-account basis using external expert advice and development plans obtained from current and prospective customers. BC Hydro also considers price forecasts for the key sector products (copper, gold, molybdenum, and coal) and the current status of environmental permitting. The forecast considers the likelihood that new mines will be completed and that existing mines will proceed with expansion plans. The 2012 mining sector forecast is lower relative to recent vintages of forecasts, due to lower price expectations for metals and coal, recent environmental decisions, and generally tighter capital markets. The outlook for mine completions in BC Hydro's forecast have been reduced and expected start dates for several new mines have been deferred. Despite a lower forecast compared to previous years, mining is expected to be one of the strongest load growth areas. This is due to announced expansions at existing mines, along with new projects that have already begun construction. Sales to the mining sector before DSM are expected to grow by about 11.8%, 7.1%, and 2.8% over the next five, 10, and 20 years, respectively.

The breakdown of BC Hydro's mid-energy load forecast by sector and for the total BC Hydro integrated system is set out in Table 5.3.

Table 5.3 Sector Breakdown of Mid-Energy Load Forecast Before DSM (Without Losses)

Energy Load (GWh/year)	F2017	F2022	F2026	F2031	Average Annual Growth Rate	
					F2012–22	F2012–31
Residential	19,800	21,900	23,600	25,700	2.0%	1.9%
Commercial	17,800	20,100	21,300	23,000	2.5%	2.1%
Industrial (without LNG)	19,000	21,200	20,800	21,100	2.6%	1.4%
Total domestic sales including sales to other utilities [a] (No LNG)	57,600	64,500	67,200	71,400	2.4%	1.8%

NOTE:
[a] FortisBC Inc. and City of New Westminster

Peak Load Forecast Components and Drivers

BC Hydro creates a 20-year peak load forecast. BC Hydro's peak demand typically occurs on a cold day in December or January, driven by electric heating demand. The primary drivers of the distribution component include housing starts and economic drivers such as retail sales, employment, and GDP. The transmission component of the peak load forecast is built up on an account-by-account basis at the same time that the industrial transmission customer forecast is created for the energy forecast described previously. Additional considerations in generating the peak forecast include planned facility expansions, and industry trends and growth in demand for B.C. exports of commodities.

The peak demand forecast generally follows the trends in the energy forecast. In the near term, the growth in distribution peak loads in the 2012 Load Forecast is slower relative to recent projections, due to a lower residential customer accounts projection

and somewhat lower expectations of economic growth. The growth in the transmission peak demand forecast is slower, due to mining deferrals and reduced demand for pulp and paper customers.

5.2.1.2 Existing and Committed Supply-Side Resources

The other major input to the energy and capacity LRBs is the existing and committed supply-side resources that serve the BC Hydro integrated system:

- Existing supply-side resources include BC Hydro's Heritage hydroelectric and thermal (natural gas-fired) generating resources, as well as independent power producer (IPP) facilities delivering electricity to BC Hydro.
- Committed supply-side resources are:
  - Resources for which material regulatory approvals have been secured (BCUC, either secured or through exemption, and environmental assessment related), if required, and for which the BC Hydro Board of Directors has authorized implementation. Examples are Mica Units 5 and 6.
  - Resources that BC Hydro is currently pursuing, e.g., resources for which the BC Hydro Board of Directors implementation approval has been secured, but for which BC Hydro has not yet authorized individual contracts, called electricity purchase agreements (EPAs). An example is BC Hydro's Standing Offer Program.

The existing and committed supply-side resources are grouped into three categories: BC Hydro heritage hydroelectric resources, BC Hydro heritage thermal resources, and EPAs with IPPs and other third-party suppliers. The following sections provide further information on the supply resource-related assumptions. The energy capability and dependable capacity of the resources are summarized in Tables 5.4 and 5.5.

<u>Heritage Hydroelectric Resources</u>

BC Hydro's most significant existing supply-side resource is its heritage hydroelectric system. BC Hydro's 30 existing hydroelectric facilities are located throughout the Peace, Columbia, and Coastal regions of B.C. BC Hydro's heritage assets are identified in Schedule 1 of the *Clean Energy Act*. Resource Smart is a BC Hydro program that promotes the identification, study, and implementation of projects that provide cost-effective energy and capacity gains at existing BC Hydro facilities. Committed Resource Smart projects such as Mica Units 5 and 6, and the Ruskin Dam and Powerhouse Upgrade Project are included in the heritage hydroelectric energy capability and dependable capacity values set out in Tables 5.4 and 5.5.

The Electricity Self-Sufficiency Regulation provides that the water conditions prescribed for purposes of the Heritage hydroelectric capability are 'average water conditions'. 'Water conditions' refers to how much water BC Hydro has in its reservoirs, and 'average water conditions' refers to the mean output of the BC Hydro Heritage hydroelectric resources over the 60-year recorded period of stream flows between October 1940 and September 2000. The energy LRBs in this EIS are based on firm energy capability – for the heritage hydroelectric resources, this capability is defined under average water conditions; for all non-heritage hydroelectric resources, like run-of-river hydro, BC Hydro uses critical water conditions (the most adverse sequence of stream flows occurring within the same 60-year period).

Heritage Thermal Resources

BC Hydro's Burrard Thermal (Burrard) and Prince Rupert Generating Stations are the only two BC Hydro-owned thermal generating stations that serve the integrated system. Burrard is a natural gas-fired generating facility located in the Lower Mainland of B.C. For purposes of the LRBs:

- Pursuant to Subsections 3(5), 6(2)(d) and 13 of the *Clean Energy Act*, Burrard's firm energy contribution is zero GWh/year
- Pursuant to Section 2 of the *Burrard Thermal Electricity Regulation* (B.C. Reg. 319/2010), Burrard's dependable capacity of 900 MW will be phased out as Mica Units 5 and 6, the Interior to Lower Mainland Transmission Reinforcement Project, and the third transformer at the Meridian Substation are introduced into service

Existing and Committed IPP Supply

BC Hydro is forecast to have the rights to approximately 14,200 GWh/year and 1,400 MW of energy and capacity in F2022 through about 120 currently active EPAs with IPPs, after taking into account forecast attrition (attrition relates to the possibility that some of the IPP projects for which EPAs have been awarded will not proceed). IPP attrition is discussed in Section 5.2.3 below.

BC Hydro used Effective Load Carrying Capability (ELCC) to represent the capacity contribution from intermittent clean or renewable IPP resources such as wind and run-of-river resources in Table 5.5 below, and the capacity LRBs in Tables 5.7 and 5.9. The ELCC method for evaluating wind and run-of-river capability uses a probabilistic approach that is sensitive to wind and run-of-river availability, rather than relying on a deterministic value for available dependable capacity. The ELCC contribution to the system is largely drawn from BC Hydro's large and reliable hydroelectric system. The ELCC method may overstate the capacity contribution of these intermittent clean or renewable resources. The incremental ELCC contributions of intermittent clean or renewable resources will decrease as more of these intermittent resources come into service.

Summary

A summary of the energy and dependable capacity of existing and committed supply-side resources is set out in Table 5.4 and Table 5.5 respectively.

Table 5.4 Energy Capability in F2022

Gigawatt Hours (GWh) – Existing and Committed Supply		F2022
Heritage hydroelectric	(a)	48,500
Heritage thermal (Prince Rupert)	(b)	200
Existing and committed IPP supply	(c)	14,200
Total supply	**(d) = a + b + c**	62,900

Table 5.5 Dependable Capacity in F2022

Megawatts (MW)		F2022
Heritage hydroelectric	(a)	11,400
Heritage thermal (Prince Rupert)	(b)	50
Existing and committed IPP supply	(c)	1,200
Reserves [a]		
Supply requiring reserves	(d) = a + b + c	12,700
14% of supply requiring reserves	(e) = d * 0.14	1,800
Supply not requiring reserves		
Alcan 2007 EPA	(f)	150
Total supply	**(g) = d – e + f**	11,100

NOTE:

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

5.2.2 Load-Resource Balances

The purpose of the LRBs is to define the future need for resources by comparing the annual mid-load forecast with the annual capability of BC Hydro's existing and committed supply-side resources. This is done with respect to two views of the system – the energy balance and the capacity balance. There are two steps to analyzing the LRBs:

- First, in Section 5.2.2.1, the LRBs are depicted without future DSM or Revelstoke Unit 6. Bracketed numbers indicate a surplus, while unbracketed numbers indicate a gap. Thus, there is a need for energy in F2017 (Table 5.6) and a need for dependable capacity in F2016 (Table 5.7).
- Second, in Section 5.2.2.2 BC Hydro's current DSM target is described, and the LRBs are presented with the DSM target and Revelstoke Unit 6 in Tables 5.8 and 5.9

5.2.2.1 Load-Resource Balances Without Demand-Side Management Target and Revelstoke Unit 6

Table 5.6 Energy Deficit/Surplus (GWh) (No LNG)

Year	LRB without DSM
F2012	(1,100)
F2013	(4,000)
F2014	(2,000)
F2015	(2,400)
F2016	(800)
F2017	100
F2018	2,300
F2019	4,300
F2020	5,400

Year	LRB without DSM
F2021	6,400
F2022	7,200
F2023	8,200
F2024	9,100
F2025	9,900
F2026	10,400
F2027	11,000
F2028	12,100
F2029	13,000
F2030	14,000
F2031	15,000

Table 5.7 Capacity Deficit/Surplus (MW) (No LNG)

Year	LRB without DSM
F2012	(800)
F2013	(850)
F2014	(550)
F2015	(250)
F2016	400
F2017	600
F2018	850
F2019	1,150
F2020	1,300
F2021	1,500
F2022	1,650
F2023	1,850
F2024	2,000
F2025	2,200
F2026	2,350
F2027	2,500
F2028	2,700
F2029	2,950
F2030	3,200
F2031	3,400

5.2.2.2 Load-Resource Balances with Demand-Side Management Target and Revelstoke Unit 6

Demand-Side Management Target

DSM is a major element in BC Hydro's long-term resource plan to fill the load-resource gap.

Section 1 of the *Clean Energy Act* defines DSM (referred to as 'demand-side measures' in the *Clean Energy Act*) to mean:

> "a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency; (b) to reduce the energy

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

Demand-Side Management Tools

The DSM target consists of expected savings from the following three main tools:

- Codes and standards are public policy instruments enacted by governments – such as building codes, energy efficiency regulations, tax measures, and local government zoning and building permitting processes – to influence energy efficiency. The DSM target relies on both Federal and Provincial Government implementation of a suite of changes to existing codes and standards.
- Rate structures are aimed at conserving energy, promoting energy efficiency, or reducing the energy demand that BC Hydro must serve, such as inclining block (stepped) rate structures. BC Hydro has conservation rates in place (or with planned implementation) for over 90% of its domestic load. Over the past five years, BC Hydro implemented four conservation rate structures for residential, commercial, and industrial customers. Estimates of energy savings from rate structures is uncertain, particularly in a low electricity rate jurisdiction such as BC Hydro's service area.
- Programs are designed to address remaining barriers to energy efficiency and conservation after codes and standards, and rate structures, and thereby capture additional conservation potential. Programs include load displacement projects, which reduce the energy demand that BC Hydro must serve as a result of existing customers self-supplying through conservation or through customer self-generation. While BC Hydro has extensive experience working with customer groups to encourage energy conservation and efficiency, the fact that DSM programs are targeting more aggressive levels of savings and that they depend on voluntary participation makes forecasting DSM savings uncertain. Two key drivers of DSM program savings are 1) participation rate of customers for that program, and 2) energy savings per participant.

In addition to these tools, there are six supporting initiatives – public awareness and education, community engagement, technology innovation, codes and standards support, information technology, and indirect and portfolio enabling – that provide a critical foundation for awareness, engagement, and other conditions to support the success of BC Hydro's DSM initiatives.

DSM Target

BC Hydro's current DSM target is 7,800 GWh/year of energy savings, with associated capacity savings of 1,400 MW, in F2021. Subsection 2(b) of the Clean Energy Act provides that it is a "British Columbia's energy objective" to "take demand-side measures and to conserve energy, including the objective of [BC Hydro] reducing its expected increase in demand for electricity by the year 2020 by at least 66% …". Based on the December 2012 mid Load Forecast, BC Hydro's current DSM target of 7,800 GWh/year exceeds the Clean Energy Act's target of "at least 66%"; the current DSM target would reduce BC Hydro's forecasted demand for energy by 78% in F2021. In addition, the DSM options examined by BC Hydro that deliver both energy and capacity – DSM Options 1, 3, 4 and 5 – either meet the subsection 2(b) 66 per cent objective (Option 1) or exceed it (Options 3, 4 and 5). Refer to section 5.2.3 (DSM Options 1 and 4) and section 5.4.2.3 (DSM Options 4 and 5).

The DSM target is aggressive and comprehensive, as it includes a broad range of codes and standards, rate structures, and programs that provide BC Hydro customers in virtually all market segments an opportunity to participate. BC Hydro is continually reviewing the DSM target to determine if it is achievable and cost-effective.

There is regulatory risk with respect to implementing the DSM target. Implementing the current BC Hydro DSM target requires a filing with the BCUC pursuant to Subsection 44.2(1)(a) of the *Utilities Commission Act* for a determination that the expenditures associated with the BC Hydro DSM target are in the public interest. Please refer to the discussion of DSM delivery risk in Section 5.2.3.

Revelstoke Unit 6

Revelstoke Unit 6 is a capacity Resource Smart project consisting of installing a sixth unit into the existing powerhouse at Revelstoke Generating Station. Revelstoke Unit 6 would provide 488 MW of dependable capacity but limited energy gains (about 30 GWh/year). For purposes of this EIS, BC Hydro includes Revelstoke Unit 6 in its LRBs; therefore, Revelstoke Unit 6 is not an alternative to the Project. Implementing Revelstoke 6 requires an application for an EAC pursuant to BCEAA and amendment of the Columbia River Water Use Plan.

Results

The energy LRB in Table 5.8 shows that, after the DSM target and Revelstoke Unit 6, there is a need for energy beginning in F2024.

Table 5.8 Energy Deficit/Surplus (GWh) with DSM Target and Revelstoke Unit 6 (No LNG)

Year	LRB without DSM and Rev 6	DSM	Revelstoke Unit 6	LRB with DSM and Rev 6
F2012	(1,100)	900	0	(2,100)
F2013	(4,000)	1,200	0	(5,200)
F2014	(2,000)	2,000	0	(4,000)
F2015	(2,400)	3,000	0	(5,500)
F2016	(800)	3,900	0	(4,700)
F2017	100	4,800	0	(4,700)
F2018	2,300	5,700	0	(3,400)
F2019	4,300	6,500	0	(2,200)
F2020	5,400	7,200	0	(1,900)
F2021	6,400	7,800	0	(1,400)
F2022	7,200	8,200	0	(1,000)
F2023	8,200	8,400	0	(200)
F2024	9,100	8,900	0	200
F2025	9,900	9,200	0	700
F2026	10,400	9,600	0	800
F2027	11,000	9,800	0	1,200
F2028	12,100	10,200	0	1,800
F2029	13,000	10,600	0	2,400
F2030	14,000	10,900	0	3,100
F2031	15,000	11,200	0	3,800

The capacity LRB shown in Table 5.9 identifies a need for new dependable capacity supply in F2025.

Table 5.9 Capacity Deficit/Surplus (MW) with DSM Target and Revelstoke Unit 6 (No LNG)

Year	LRB without DSM and Rev 6	DSM	Revelstoke Unit 6 (after Reserves)	LRB with DSM and Rev 6
F2012	(800)	150	0	(950)
F2013	(850)	150	0	(1,000)
F2014	(550)	350	0	(900)
F2015	(250)	500	0	(700)
F2016	400	650	0	(250)
F2017	600	800	0	(200)
F2018	850	950	0	(100)
F2019	1,150	1,100	400	(400)
F2020	1,300	1,250	400	(350)
F2021	1,500	1,350	400	(250)
F2022	1,650	1,450	400	(250)
F2023	1,850	1,500	400	(100)
F2024	2,000	1,600	400	–
F2025	2,200	1,650	400	100
F2026	2,350	1,750	400	200
F2027	2,500	1,800	400	300
F2028	2,700	1,850	400	450
F2029	2,950	1,900	400	600
F2030	3,200	2,000	400	800
F2031	3,400	2,050	400	950

5.2.3 Load/Resource Balance Uncertainty

There are a number of uncertainties that result in risks that would have significant consequences in terms of BC Hydro being able to reliably meet its service obligation.

Load Forecast Uncertainty

BC Hydro's Load Forecast is sensitive to a number of variables, including economic conditions:

- Factors that can lead to lower load than forecast include:
  - An increase in the value of the Canadian dollar, which would slow commodity exports from B.C.
  - Reduction in growth in China and elsewhere, leading to a slowing of commodity demand and lower prices
- Factors that could lead to higher than forecast electrical sales include:
  - Strengthening world demand for commodities and strengthening business confidence, leading to increased investment in B.C. and thus increased growth and electrification. There is unprecedented load growth potential in the north of B.C., driven by mining and shale natural gas (e.g., there is up to 500 MW of mining load in the north of B.C.).

- Electrification, which is the process of switching specific end uses in the residential, commercial, transportation, and industrial sectors from utilization of fossil-based fuels to using clean or renewable electricity. BC Hydro analyzed potential electrification load such as electric plug-in vehicles and fuel choice in residential space and water heating applications, but has only included a small portion of potential electrification load in the 2012 Load Forecast. For example, the 2012 Load Forecast includes about 150 GWh/year of electric vehicle load by F2022.

BC Hydro addresses load forecast uncertainty by developing high and low forecast bands. The intention of this analysis is the creation of high and low forecast bands with approximately 10% and 90% exceedance probabilities, respectively. As stated above, for planning purposes, BC Hydro uses its mid-load forecast. The high and low forecast bands are used to provide an indication of the magnitude of load uncertainty. Figure 5.1 and Figure 5.2 at the end of this section depict the 2012 mid-energy and capacity load forecasts, respectively, and the high and low uncertainty band forecasts before DSM.

The uncertainty bands generated as part of the Load Forecast do include the effects of variable economic drivers such as GDP (as provided from third-party economic forecasts), but the mid-load forecast inherently assumes smoothed projections of future growth. In long-term resource planning proceedings, the BCUC agreed with BC Hydro that it is not credible to forecast the precise timing of economic boom and bust cycles. While BC Hydro has incorporated reasonably foreseeable short-term conditions in creating its forecasts, the purpose of the mid-load forecast is to predict average long-term trends in load growth, which will invariably include periods of higher and lower economic growth than the average.

LNG Load

British Columbia's *Natural Gas Strategy and Liquefied Natural Gas Strategy* (B.C. Ministry of Energy, Mines and Natural Gas 2012a, 2012b) details the B.C. Government's commitment to LNG exports and outlines the priorities that are to guide development of this new industry. To date, several LNG proponents have approached BC Hydro and/or the B.C. Government with respect to LNG projects for the B.C. north coast.

For the purposes of this EIS, potential non-compression LNG demand could be between about 800 GWh/year to about 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand.

The energy LRB shown in Table 5.10 identifies that the upper range of this LNG load would advance the need for new energy resources from F2024 to F2019.

Table 5.10 Energy Deficit/Surplus (GWh) with DSM Target, Revelstoke Unit 6 and LNG

Year	LRB with DSM and Rev 6 and no LNG	LRB with DSM, Rev 6 and Low LNG	LRB with DSM, Rev 6 and High LNG
F2012	(2,100)	(2,100)	(2,100)
F2013	(5,200)	(5,200)	(5,200)
F2014	(4,000)	(4,000)	(4,000)
F2015	(5,500)	(5,500)	(5,500)
F2016	(4,700)	(4,700)	(4,700)
F2017	(4,700)	(4,700)	(4,700)
F2018	(3,400)	(3,400)	(3,400)
F2019	(2,200)	(1,400)	300
F2020	(1,900)	(1,000)	4,700
F2021	(1,400)	(600)	5,200
F2022	(1,000)	(100)	5,600
F2023	(200)	600	6,400
F2024	200	1,000	6,800
F2025	700	1,600	7,300
F2026	800	1,600	7,300
F2027	1,200	2,000	7,700
F2028	1,800	2,700	8,400
F2029	2,400	3,300	9,000
F2030	3,100	4,000	9,700
F2031	3,800	4,600	10,400

The capacity LRB shown in Table 5.11 identifies that the upper range of the LNG load would advance the need for new capacity resources from F2025 to F2020.

Table 5.11 Capacity Deficit/Surplus (MW) with DSM Target, Revelstoke Unit 6 and LNG

Year	LRB with DSM and Rev 6 and No LNG	LRB with DSM, Rev 6 and Low LNG	LRB with DSM, Rev 6 and High LNG
F2012	(950)	(900)	(900)
F2013	(1,000)	(1,000)	(1,000)
F2014	(900)	(900)	(900)
F2015	(700)	(700)	(700)
F2016	(250)	(200)	(200)
F2017	(200)	(200)	(200)
F2018	(100)	(100)	(100)
F2019	(400)	(300)	(100)
F2020	(350)	(200)	500
F2021	(250)	(200)	500
F2022	(250)	(200)	500
F2023	(100)	0	700
F2024	0	100	800
F2025	100	200	900
F2026	200	300	1,000
F2027	300	400	1,100
F2028	450	500	1,200
F2029	600	700	1,400
F2030	800	900	1,600
F2031	950	1,000	1,700

DSM Reliance and Delivery Risk

BC Hydro is relying on the DSM target to meet a large percentage of both the energy and capacity gaps:

- The DSM target amounts to about 107% of the energy LRB gap in F2021, meaning the current DSM target creates an energy surplus
- The 1,400 MW of capacity savings in F2021 associated with the DSM target is being relied on to contribute a large portion of the capacity needs. The DSM target represents about 85% of the capacity LRB gap in F2021. At this level, the DSM target peak demand savings are more than the dependable capacity the Project would provide, or the three largest Resource Smart projects combined – Mica Units 5 and 6, and Revelstoke Unit 6 (after reflecting the associated reserve requirements that would be required for supply-side resources).

Precise forecasting of DSM savings for long-term planning purposes is challenging for several reasons, including:

- Limited BC Hydro experience with respect to targeting and achieving savings at and above the current DSM target level
- Model uncertainty, in particular, linking customer response to DSM actions, and forecasting the timing and efficacy of regulatory (codes and standards) changes

The BC Hydro DSM target is aggressive and entails delivery risks – that is, the risk that the current DSM target will not deliver the projected energy and particularly capacity

savings within the specified time frame. Ensuring an adequate capacity supply is the primary concern for BC Hydro, since capacity is required at specific times to meet peak load requirements and to maintain system security and reliability. Capacity resources also support intermittent clean or renewable generation resources that primarily supply energy so that generation is available when the loads require it. On the capacity side, a shortfall caused by missed DSM targets could undermine BC Hydro's fundamental obligation to serve its customers:

- The *Utilities Commission Act* service obligation means that BC Hydro must make sure its customers' demand is met at the peak load every day
- The risk that DSM will not deliver the anticipated 1,400 MW of dependable capacity savings by F2021 is greater than the risk that DSM does not deliver the anticipated 7,800 GWh of energy savings by F2021. There are two sources of uncertainties regarding DSM-related capacity savings:
    - The underlying uncertainty around the energy savings themselves
    - The capacity factors used to translate energy savings into the associated level of capacity savings. These factors have additional uncertainty, due to the lack of precise knowledge about how energy savings from multiple sources would reduce peak demand.
- The consequence of DSM not delivering the anticipated 1,400 MW of dependable capacity savings by F2021 is greater as compared to failure to deliver the anticipated energy. Generally, external markets can be counted on for supply of energy across the year (albeit with costs), but during winter peaks there are issues with:
    - The illiquid (thinly traded) nature of the market for capacity
    - Insufficient transmission capacity
    - The U.S. market not having surplus to sell

This is one of the reasons why BC Hydro develops contingency resource plans that can provide dependable capacity to meet its customers' requirements.

There are delivery risks associated with each major strategic element of the DSM target:

- Codes and standards are subject to Federal and/or B.C. Government approval and implementation, and may be deferred in implementation, may not apply to all equipment and buildings governments have planned, may have varying levels of minimum efficiency standards, or may depend on compliance by consumers, retailers, builders, etc.
- Conservation rate structures are subject to BCUC approval, and customer response to price signals is uncertain in a relatively low electricity rate jurisdiction such as BC Hydro's service area
- Programs rely on voluntary customer participation and the rate of savings per participant is uncertain

BC Hydro developed the following ranges around the current DSM target (DSM Option 2), referred to as DSM Option 1 and DSM Option 3:

- In Option 1, the DSM program component is reduced to achieve about 75% of the BC Hydro DSM target. All other tactics are similar to those employed in the

BC Hydro DSM target. Option 1 is expected to deliver about 7,500 GWh/year of energy savings and 1,200 MW of dependable capacity savings by F2021.

- DSM Option 3 targets more electricity savings than the current BC Hydro DSM target by expanding program efforts while keeping the level of activity and savings for codes and standards, and conservation rate structures, consistent with the DSM target. Program activities are expanded with increased incentives, advertising, or technical support to address customer barriers as means of potentially increasing customer participation. As a result, program costs increase to deliver the higher volume of projects and resulting applications. DSM Option 3 is expected to deliver 9,200 GWh/year of energy and 1,400 MW of capacity in F2021. BC Hydro notes that DSM Option 3 on its own is not an alternative to the Project because, on its own, Option 3 defers the energy LRB gap by five years and does not defer the capacity LRB gap.

IPP Delivery Uncertainty – IPP Attrition and Price Risk and EPA Renewals

IPP projects are subject to attrition, with EPAs being terminated for various reasons such as unexpected cost increases, financing obstacles, and permitting difficulties. For the most recent broadly-based BC Hydro power acquisition process, the Clean Power Call, a 30% attrition factor was assumed. The attrition rate for the F2006 Call is about 55% (excluding two coal-fired projects). There is also risk that IPP bid prices are not ‘all in’ prices. IPPs periodically request EPA amendments after power acquisition processes have been completed, including uplifts to EPA prices and delays in the commercial operation date. Both the attrition rate and the request for EPA amendments show that IPPs have been hampered by unanticipated development cost increases and project delays.

EPAs with IPPs and other third parties have varying durations, ranging from 15 to 40 years. BC Hydro assumes for purposes of the LRBs presented in this EIS that, with the exception of EPAs with bioenergy generation facilities, a portion of the EPAs with IPPs (about 75% of clean or renewable IPPs) will be renewed upon expiry, and that those IPP facilities will continue to provide the same amount of electricity to BC Hydro. BC Hydro assumes that about 50% of bioenergy EPAs will be renewed. In BC Hydro’s view, it is not prudent to plan on the renewal of all existing and committed EPAs with biomass generation facilities, due to fuel pricing and supply risk. In the last 10 years of the planning horizon, bioenergy EPAs totalling approximately 600 GWh/year and 60 MW of firm energy and dependable capacity are set to expire. Overall, there is no assurance that 1) IPP projects will continue operations past the expiry of the EPAs, 2) that IPPs will contract with BC Hydro if they do continue to operate, or 3) that IPPs will contract at a price comparable to their current real dollar prices. All of these factors represent significant supply and price risk to BC Hydro.

As noted above in Section 5.2.1.2, the ELCC method may overstate the capacity contribution of intermittent clean or renewable resources.

Contingency Planning

Contingency planning is done as a reliability management tool to manage the risk (consequences) of not being able to meet load. The contingency plan seeks to prepare to meet greater demand than forecast, and seeks reduce the lead time for contingency resources to be in service, if the need arises. Contingency planning is part of good utility

practice; it is also a component of long-term resource planning that is recognized as important in the BCUC's Resource Planning Guidelines.

In developing its contingency plan, BC Hydro uses both capacity and energy shortfall risks summarized above. BC Hydro considers load forecast uncertainty (including LNG), DSM delivery risk and IPP delivery risk:

- Capacity requirements are the primary concern for BC Hydro, since capacity is required to meet peak load requirements and to maintain system security and reliability. After implementation of Revelstoke Unit 6, the capacity resources available to BC Hydro are limited to natural gas-fired generation Simple Cycle Gas Turbines (SCGTs) and/or pumped storage. The DSM target in particular creates significant uncertainty regarding the volumes of capacity that will ultimately be delivered. As described above, BC Hydro is relying on the current DSM target to deliver 1,400 MW of peak reduction (capacity savings) by F2021.
- BC Hydro considers additional uncertainty with respect to the reliance on ELCC for intermittent clean or renewable resources and the potential for increased IPP attrition. Uncertainty analysis indicates that the shortfalls shown in Table 5.12 below are adequate for planning purposes; however, using ELCC for intermittent clean or renewable resources and IPP attrition are risks that BC Hydro will need to continue to monitor.

Refer to Table 5.12 for a description of the shortfall risks addressed by BC Hydro's Contingency Resource Plan, and to Figure 5.3 for a graphic depiction of the Contingency Resource Plan LRB.

Table 5.12 BC Hydro Contingency Resource Plan Shortfall Risks

Risk	Rationale	Capacity Reduction for Contingency Planning Purposes (MW)		Energy Shortfall Risk (GWh/year)	
		F2022	F2031	F2022	F2031
General Load Forecast Uncertainty [a]	Peak load and energy requirements can increase as a result of either sustained growth or low temperatures at winter peak	1,100	1,450	8,200	9,800
DSM Delivery Risk	The BC Hydro DSM target has a significant range of delivery risk where the variability is driven by implementation of codes and standards, customer response to programs and rates	450	550	2,700	3,500

NOTE:
[a] LNG load could add approximately 6,600 GWh/year and 800 MW to the amounts shown

As discussed in Section 5.5.2.8 below, if BC Hydro were to choose natural gas-fired generation such as SCGTs in lieu of the Project, it would deprive itself of being able to rely on SCGTs as a contingency resource if, for example, DSM does not deliver the anticipated capacity savings.

Project Range of In-Service Dates

Given the uncertainty described in this section and to provide a basis for Project alternatives evaluation, BC Hydro evaluated a range of Project in-service dates from F2022 to F2024. However, given the uncertainties around the amount and timing of potential LNG load and DSM and IPP delivery, BC Hydro considers it prudent to proceed with the Project for its earliest in-service date of F2022.

5.2.4 Conclusion

Based on the LRBs in Table 5.8 and Table 5.9, there are energy and capacity gaps within the 20-year planning period that must be filled with supply-side options. As described in Section 5.4, targeting more DSM is not a viable alternative to the Project. Section 5.5 contains the available supply-side resources analysis, including the trade-offs between different supply-side resources to address the energy and capacity deficits set out in Table 5.8 and Table 5.9, which forms the basis of the need for the Project.

5.3 Purpose of the Project

The EIS Guidelines confirm that the EIS will present the ‘purpose of’ the Project, and goes on to state that the purpose of the Project “will be established from the perspective of the Proponent, and will provide context for consideration of alternatives to the Project” in Sections 5.4 and 5.5. The EIS Guidelines also require that the EIS describe the objectives the Project is designed to achieve.

The purpose of the Project is to:

- Cost-effectively meet BC Hydro’s forecasted need for energy and capacity identified in Section 5.2.2. Refer to Section 5.3.1.
- Align with the relevant objectives of Section 2 of the *Clean Energy Act* and relevant B.C. Government policy statements, which in turn were used to develop Project-specific objectives, including the objective to maximize the development of the hydroelectric potential of the Site C Flood Reserve. Refer to Section 5.3.2.

5.3.1 Meeting Identified Need

The Project would provide about 5,100 GWh/year of average energy and up to 1,100 MW of dependable capacity. As demonstrated in Table 5.8 and Table 5.9, even with the additional actions of implementing the current BC Hydro DSM target and Revelstoke Unit 6, BC Hydro will have a projected energy shortfall beyond F2023, and a projected capacity shortfall beyond F2024.

Table 5.13 and Table 5.14 indicate that, by constructing the Project at its earliest in-service date of F2022, BC Hydro will have sufficient energy and capacity to meet its mid-load forecast energy and peak demand without LNG throughout the 20-year planning horizon.

Table 5.13 Energy Surplus/Deficit (GWh) with DSM Target, Revelstoke Unit 6 and the Project (No LNG)

Year	LRB with DSM, Rev 6 & Site C Clean Energy Project
F2012	(2,100)
F2013	(5,200)
F2014	(4,000)
F2015	(5,500)
F2016	(4,700)
F2017	(4,700)
F2018	(3,400)
F2019	(2,200)
F2020	(1,900)
F2021	(1,400)
F2022	(1,400)
F2023	(4,600)
F2024	(4,900)
F2025	(4,400)
F2026	(4,300)
F2027	(3,900)
F2028	(3,300)
F2029	(2,700)
F2030	(2,000)
F2031	(1,300)

Table 5.14 Capacity Surplus/Deficit (MW) with DSM Target, Revelstoke Unit 6 and the Project (No LNG)

Year	LRB with DSM, Rev 6 & Site C Clean Energy Project
F2012	(950)
F2013	(1,000)
F2014	(900)
F2015	(700)
F2016	(250)
F2017	(200)
F2018	(100)
F2019	(400)
F2020	(350)
F2021	(250)
F2022	(250)
F2023	(1,050)
F2024	(950)
F2025	(850)
F2026	(750)
F2027	(650)

Year	LRB with DSM, Rev 6 & Site C Clean Energy Project
F2028	(500)
F2029	(300)
F2030	(150)
F2031	0

5.3.2 Aligning with the *Clean Energy Act* and B.C. Government Policy

Section 2 of the *Clean Energy Act* sets out B.C. Government objectives, referred to as "British Columbia's energy objectives", that BC Hydro must respond to and that the BCUC must consider and be guided by in various applications. The alignment of the Project with the relevant *Clean Energy Act* energy objectives is described in Table 5.15.

Table 5.15 Project Alignment with *Clean Energy Act* Objectives

Clean Energy Act Objective	How the Project Supports the Objective
At least 93% generation from clean or renewable resources	The Project is a clean or renewable resource as defined by Section 1 of the *Clean Energy Act*.[a] The Project provides clean or renewable energy and dependable capacity, and also has the ability to shape, firm, and help integrate intermittent clean or renewable resources such as wind and run-of-river. Refer to Section 7.4.3 in Volume 1 Section 7 Project Benefits.
To ensure that BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America	The Project is a cost-effective resource for energy and capacity compared to alternative supply options; refer to Section 5.5
To reduce greenhouse gas (GHG) emissions	As a hydroelectric resource, the Project emits virtually no GHG emissions when compared to natural gas-fired electricity resources, and on a per GWh basis, emits a similar amount of GHGs as other clean or renewable resources such as wind. Refer to Section 7.4.2 in Volume 1 Section 7 Project Benefits and to Volume 2 Section 15 Greenhouse Gases.
To encourage economic development and the creation and retention of jobs	The Project is a job-intensive capital project that will create employment in B.C. during the construction period. Refer to Section 7.3 in Volume 1 Section 7 Project Benefits.
To maximize the value of B.C.'s generation and transmission assets	The Project provides additional benefits (e.g., shaping and firming benefits) to optimize the value of B.C.'s generation and transmission assets. In addition, as the third project on one river system, the Project would generate 35% of the energy produced at the W.A.C. Bennett Dam, with 5% of the reservoir area. Refer to Section 7.4.1 in Volume 1 Section 7 Project Benefits.

NOTE:

[a] "Clean or renewable resources" are defined in Section 1 of the *Clean Energy Act* as follows: "clean or renewable resource means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource". To date, biogenic waste, waste heat and waste hydrogen have been added to this definition pursuant to the B.C. Clean or Renewable Resource Regulation, B.C. Reg. 291/2010.

In addition to Section 2 of the *Clean Energy Act*, the 2007 Energy Plan sets the policy framework in which BC Hydro develops resources. The 2007 Energy Plan stresses the development of clean or renewable resources. While a number of 2007 Energy Plan

Policy Actions have been overtaken by Section 2 of the *Clean Energy Act*, there are 2007 Energy Plan Policy Actions relevant to the review of natural gas-fired generation and other potential alternatives to the Project, as set out in Table 5.16.

Table 5.16 Relevant 2007 Energy Plan Policy Actions

Policy Action	Section in Environmental Impact Statement
18 – All new electricity generation projects will have zero net GHG emissions	The B.C. *Environmental Management Act* (S.B.C., 2003, c.53) is described in further detail in Section 5.5.2.8. All new natural gas-fired generation analyzed in the alternatives to Project analysis factors in the zero net GHG emissions requirement.
20 – Require zero GHG emissions from any coal thermal electricity facilities	See above in respect of Policy Action No. 18; the current status of coal-fired generation with carbon capture and storage is examined in Section 5.4.2.2
23 – No nuclear power	Nuclear technology is not an alternative to the Project; refer to Section 5.4.2.1

BC Hydro developed the Project objectives listed in Table 3.1 in Volume 1 Section 3 Project Overview, from the *Clean Energy Act* and the 2007 Energy Plan. BC Hydro's objective to ensure a long-term source of energy and capacity and to optimize existing assets on the Peace River system is supported by the B.C. Government's reservation of Crown land in the Peace River watershed for the purposes of hydroelectric development through an Order-in-Council in 1957 (further described in Section 6.2 in Volume 1 Section 6 Alternative Means of Carrying Out the Project). This Order-in-Council was subsequently amended and the Site C Flood Reserve described in Section 6.2 of this EIS defines the bounds within which the Project can be developed. As a result, to fulfill the Project objectives, the specific purpose of the Project design is to cost-effectively maximize the development of the hydroelectric potential of the Site C Flood Reserve to meet the need and maximize the benefits to British Columbia.

5.4 Identification of Potential Alternatives to the Project and Screened Resources

The EIS Guidelines call for the EIS to describe the functionally different ways to meet the need for the Project, that is, the technically and economically feasible alternatives to the Project. The EIS is to identify the alternatives to the Project that were considered. The EIS is to describe the criteria used to compare the Project to other alternatives, with consideration of the major financial, technical, environmental, and economic development attributes, per the Agency Need/Alternatives Operational Policy Statement. This analysis must be done to a level of detail that is sufficient to compare the Project to the alternatives.

BC Hydro's analysis of the potential alternatives to the Project is contained in two parts:

- This section provides an overview of the identification and review process for potential alternatives to the Project, and concludes with the resources that were screened out on the basis that they are not viable. This first category of potential alternatives is referred to as the Screened Resources. The Screened Resources consist of:
    - Supply-side resources that are not permitted by or are inconsistent with B.C. Government legal requirements, namely: Burrard, Large hydroelectric projects

prohibited by the *Clean Energy Act*, nuclear, and external market purchases/imports including the Canadian Entitlement (Section 5.4.2.1)

  - Supply-side resources that are not technically or economically feasible alternatives to the Project. These resources are: Coal-fired generation with carbon capture and storage, wave, tidal and solar (Section 5.4.2.2).
  - Increased levels of DSM beyond the current BC Hydro DSM target (i.e., DSM Options 4 and 5) described in Section 5.4.2.3
  - DSM options designed to deliver capacity savings during BC Hydro's peak load periods (Section 5.4.2.4)

- Section 5.5 describes the second category of potential alternatives – the available resources and their attributes. The available resources are supply-side resources that, when used in various combinations, can meet the need identified in Section 5.2. The available resources encompass:
  - Clean or renewable IPPs, including wind, run-of-river hydro, biomass, geothermal, and pumped storage
  - BC Hydro Resource Smart potential
  - Clean or renewable IPPs and/or Resource Smart combined with some natural gas-fired generation. Natural gas-fired generation is constrained by the Subsection 2(c) *Clean Energy Act* target "to generate at least 93% of the electricity in British Columbia from clean or renewable resources…". This target and its effect on natural gas-fired generation are addressed in Section 5.5.2.8.

5.4.1 Alternatives Identification

5.4.1.1 2010 Resource Options Report

The information for potential alternatives to the Project derives in large part from the 2010 Resource Options Report, which is a database of various resource options considered for meeting BC Hydro's future energy and capacity needs. In line with long-term resource planning best practices and the BCUC's Resource Planning Guidelines, BC Hydro included and assessed a wide variety of DSM, generation supply-side resource, and transmission options in its 2010 Resource Options Report. BC Hydro developed resource option attributes and costs reflecting information from BC Hydro project experience, consultant studies, and First Nations and public stakeholder input, including from members of the IPP community. A number of studies were conducted by BC Hydro and its consultants, including:

- Powertech Labs Inc., Coal with Carbon Capture & Sequestration for Long-Term Transmission Inquiry (September 15, 2009)
- Garrad Hassan Canada Inc., Updated Capital and O&M Cost Assumptions for Wind Power Development in British Columbia (November 26, 2010)
- Kerr Wood Leidal Associates Ltd., Run-of-River Hydroelectric Resource Assessment for British Columbia – 2010 Update (March 2011)
- Industrial Forest Service Ltd., Wood-Based Biomass Energy Potential of British Columbia (January 2011)

- Knight Piésold Ltd., Evaluation of Pumped Storage Hydroelectric Potential (November 30, 2010)
- Knight Piésold Ltd., Evaluation of Pumped Storage Hydroelectric Potential in the North Coast Region of British Columbia (March 15, 2012)
- Hatch, Pumped Storage at Mica Generating Station: Preliminary Cost Estimate (December 2010)

BC Hydro also relied on other third-party reports. These are referenced in the discussions of specific resources in Sections 5.4 and 5.5.

The 2010 Resource Options Report-related engagement process consisted of working with people and organizations with technical expertise to gather and review information on DSM and supply-side options in B.C. Focused workshops and meetings were held on specific energy sources, including:

1. DSM: BC Hydro engaged with its Electricity Conservation and Efficiency Committee
2. Run-of-river hydro: A series of workshop meetings were held in September 2010. A draft of the Kerr Wood Leidal resource assessment report was posted on BC Hydro's website for comment prior to finalization.
3. Wind resources (onshore and offshore): A working group was established in September 2010 to review drafts of the Garrad Hassan report on onshore/offshore wind cost assumptions, results of onshore wind potential, methodology, and assumptions for determining offshore wind potential. An individual meeting with IPPs was held in October 2010.
4. Biomass – Biogas, Municipal Solid Waste and Wood-Based: A series of workshop meetings were held between August 2010 and November 2010. A biomass working group, including representatives from the B.C. Ministry of Energy, Mines and Natural Gas, the B.C. Ministry of Forests, Lands and Natural Resource Operations, and consultants Industrial Forest Services Ltd., M.D.T. Ltd. and Murray Hall Consulting Ltd., participated in the studies to determine long-term availability potential and cost. A draft copy of the Forest Service report was circulated for comment in November 2010.
5. Geothermal: A series of workshop meetings were held in September 2010. It was agreed that data compiled by GeothermEX for the Western Renewable Energy Zone initiative would be the basis for conventional geothermal potential. It was recognized that this represents a conservative estimate of the potential, as it does not include resources from enhanced geothermal or co-produced fluids that are likely to be found in B.C.
6. Natural Gas-Fired Generation: Representatives from IPPs, consumer organizations, and consultants met in September 2010 and decided there was no need to establish a working group.
7. Pumped Storage: Two consultants – Knight Piésold and Hatch – participated with representatives from IPPs, individual developers, and consulting firms in a working group that met between July and October 2010. Among other things, this group reviewed the Knight Piésold study methodology and preliminary results, and shared information on potential sites, technical work that had been done to date, etc.

BC Hydro also received submissions from workshop participants, which informed the Resource Options Report, including Ocean Renewable Energy Group's August 14, 2009 submission entitled "Resource Options Workshop – Wave and Tidal". BC Hydro met with the B.C. Ministry of Environment and environmental organizations (Nature Trust of Canada, Ducks Unlimited, BC Sustainable Energy Association, David Suzuki Foundation, West Coast Environmental Law Association, Westcoast Wilderness Committee, Watershed Watch Salmon Society, Sierra Club, and Pembina Institute) to review the methodology for the environmental attributes. BC Hydro reported out on the draft 2010 Resource Options Report results on December 8, 2010. BC Hydro circulated a draft of the 2010 Resource Options Report and established a written comment period of between December 8 and 31, 2010.

Resource Technologies

The result is the 2010 Resource Options Report, which looks out 20 years for DSM and supply-side options. Table 5.17 shows the B.C.-based resources that are identified in the Resource Options Report and discussed in Sections 5.4.2 and 5.5.2.

Table 5.17 Resource Technologies Identified

Technology	Screened/Available Resource	Section Reference
Demand Side Management Options		
DSM Options 4 and 5	Screened Resource	Section 5.4.2.3
DSM capacity-only initiatives	Screened Resource	Section 5.4.2.4
Clean or Renewable Resources		
Wave and tidal	Screened Resource	Section 5.4.2.2
Solar	Screened Resource	Section 5.4.2.2
Wind (on-shore and off-shore)	Available Resource	Section 5.5.2.2 and Section 5.5.2.3
Run-of-river hydro	Available Resource	Section 5.5.2.1
Geothermal	Available Resource	Section 5.5.2.7
Biomass	Available Resource	Section 5.5.2.4, Section 5.5.2.5, and Section 5.5.2.6
Large hydroelectric (other than the Project)	Screened Resource	Section 5.4.2.1
Pumped storage (dependable capacity only)	Available Resource	Section 5.5.2.10
BC Hydro Resource Smart	Available Resource	Section 5.5.2.9
Fossil Fuel Resources		
Coal-fired generation with carbon capture and storage	Screened Resource	Section 5.4.2.2
Natural gas-fired generation SCGTs (dependable capacity) CCGTs (firm energy)	Available Resource within the 93% *Clean Energy Act* clean or renewable target	Section 5.5.2.8

2010 Resource Options Report Attributes

A set of technical, financial, environmental, and economic development attributes were developed in the 2010 Resource Options Report for each technology to compare and evaluate the resource options and for IRP portfolio analysis. Section 5.5.1 describes these attributes.

Limitations

The 2010 Resource Options Report database of resources contains sufficient information on physical, financial, environmental, and economic development characteristics to allow for both economic and environmental analysis at a planning level. However, because the 2010 Resource Options Report values present a high level planning assessment of resource type costs, the values:

- Do not reflect site-specific information, permitting constraints, and other development risks. For example, the UECs estimated for the geothermal resource options do not reflect the exploration risks associated with drilling and proving site-specific resource potential.
- May not predict accurately future prices set through BC Hydro's power acquisition processes. Historically, the resource options with the lowest unadjusted Unit Energy Cost (UEC) values are not always bid into BC Hydro's power acquisition processes. A case in point is the geothermal resource option, which appears to be low cost, based on an unadjusted UEC value of $88/MWh ($F2013) and upward, but has never been bid into a BC Hydro power acquisition process by IPPs. Refer to Section 5.5.2.

5.4.1.2 Wind Cost Update

The wind UECs in the 2010 Resource Options Report were based on wind generation modelling studies completed by GEC-KEMA (formally known as DNV-GEC) in May 2009 and September 2009, and cost assumptions provided by Garrad Hassan Canada Inc. in November 2010. These studies were conducted and completed as changes in wind turbine efficiencies and apparent changes in wind turbine pricing were taking place.

The 2010 Resource Options Report wind UECs have been revised to reflect observed changes in turbine efficiencies and wind turbine prices that have occurred over the past three years:

- Wind turbine efficiencies: BC Hydro commissioned DNV-KEMA in May 2012 to provide a wind turbine power curve for International Electrotechnical Commission (IEC) Class III wind sites (corresponding to low average wind speeds) and to update the power curves for IEC Class I and II wind sites (corresponding to high and medium average wind speeds, respectively). The three wind power curves were developed by blending wind turbine power curves for a number of recent and current turbine models for each of the three IEC classes. The new power curves were then applied to the modelled wind speeds from the original 2010 Resource Options Report Wind Data Study to create new hourly generation profiles for each wind project. In this analysis, no changes were assumed for turbine hub heights, installed wind capacity of the individual wind projects, or wind farm losses. With the application of the revised power curves, the annual net energy production increased on average by 13% for IEC Class I wind projects, 6% for IEC Class II wind projects, and 18% for IEC Class III wind projects.
- Wind turbine prices: Over the past decade, wind turbine prices have undergone considerable changes. Turbine prices steadily increased from 2002 to 2009. Turbine prices peaked in the first half of 2009, but have dropped since then by approximately 20% to 30%. The trends in turbine prices have been subject to a number of reports (Bolinger and Wiser 2011; National Renewable Energy Laboratory 2012; U.S.

Department of Energy 2012). The increase in turbine prices has been attributed to increased material and labour costs, upscaling of turbine size, decline in the U.S. dollar relative to the euro, increased costs in turbine warranty provisions, and a general increase in turbine manufacturer profitability, due in part to strong demand growth, and turbine and component supply shortages. The decline in wind turbine prices since 2009 has coincided with the downturn in the global economic situation. The reduced turbine demand has increased competition among manufacturers, and shifted the turbine market from a seller's market to a buyer's market.

- The current wind turbine prices are forecasted to persist through 2015, but it is uncertain if the low sale margins can be maintained by the manufacturers in the long term. Improved efficiencies in the manufacturing process, continued technical advancements, and potential competition from Chinese turbine manufacturers may help keep turbine prices low in the future. At the same time, resurgence in wind turbine demand, resulting in supply chain pressures similar to those observed between 2004 and 2009, could counter the cost reductions and increase wind turbine prices. In light of these uncertainties, BC Hydro decreased the wind turbine price by 15% from the original assumption used in the 2010 Resource Options Report.

Refer to Figure 5.4 at the end of this section, which shows the updated onshore wind supply curve, which takes into account the new turbine efficiencies and lower turbine costs in comparison to the onshore wind supply curve based on the 2010 Resource Options Report. The costs are based on a cost of capital of 8%; refer to Section 5.5.3.4 for a discussion of cost of capital. The updated (lower) wind UECs are used in the available resources analysis in Section 5.5.

5.4.2 Screened Resources

Potential alternatives were screened to determine if they are viable. There are four categories of Screened Resources determined to be not viable, with the specific reasons set out in this part in respect of each resource.

5.4.2.1 Category 1: Barred Resources

The Agency Need/Alternatives Policy Statement provides that "alternatives to the project should be established in relation to the project need and purpose and from the perspective of the proponent" (CEA Agency 2007). Accordingly, those resources that are legislatively barred (Burrard, the large hydroelectric projects prohibited by the *Clean Energy Act,* and external markets) or policy barred (nuclear) are not available to BC Hydro and thus are not alternatives to the Project.

<u>Burrard</u>

Burrard is not an alternative to the Project, as it is an existing resource that is already being relied on to the extent permitted under Sections 3(5), 6(2)(d) and 12 of the *Clean Energy Act*, which provides that the Burrard firm energy contribution is 0 GWh/year, and the Burrard Thermal Electricity Regulation, which requires that Burrard's dependable capacity of 900 MW be phased out as Mica Units 5 and 6, the Interior to Lower Mainland Transmission Reinforcement Project, and the third transformer at the Meridian Substation are introduced into service by about F2016, well before the Project's earliest

in-service date. After this, BC Hydro will only be able to operate Burrard in case of emergency or for voltage support.

Other Large Hydro Barred by *Clean Energy Act*

Sections 10 and 11, and Schedule 2, of the *Clean Energy Act* prohibit the development of the following large hydroelectric projects: Murphy Creek, Border, High Site E, Low Site E, Elaho, McGregor Lower Canyon, Homathko River, Liard River, Iskut River, Cutoff Mountain, and McGregor Diversion. Cutoff Mountain on the Skeena River and McGregor Diversion are also legislatively barred by respectively 1) the B.C. *Fish Protection Act* (S.B.C., 1997, c.21), which designates the Skeena River as a "protected river" and prohibits the construction of bank-to-bank dams on the Skeena River, and 2) the B.C. *Water Protection Act* (R.S.B.C., 1996, c.484), which prohibits the construction of "large-scale projects" such as McGregor Diversion capable of transferring a peak instantaneous flow of 10 or more cubic metres of water per second between major watersheds. McGregor Diversion would divert most of the McGregor River flows across the divide between the Pacific and Arctic watersheds into the Peace River basin.

Aside from pumped storage, which is examined in Section 5.5.2.10, BC Hydro is not aware of any other B.C.-based potential large hydroelectric projects that could be an alternative to the Project. The alternative means of delivering the Project are discussed in Volume 1 Section 6 Alternative Means of Carrying Out the Project.

Nuclear

Policy Action No. 23 of the 2007 Energy Plan provides that "nuclear power is not part of the Province of B.C.'s future" and that the B.C. "government rejects nuclear power as a strategy to meet British Columbia's future energy needs". While the Federal Government has siting authority over nuclear electricity-generating facilities (*Society of Ontario Hydro Professional and Administrative Employees v. Ontario Hydro*. 1993. 3 S.C.R. 327 (S.C.C.)), the B.C. Government can prevent BC Hydro from purchasing electricity from nuclear electricity-generating facilities through its ability to issue directions to BC Hydro and the BCUC. Therefore, nuclear power is not an alternative to the Project.

External Market/Imports

Pursuant to Section 6 of the *Clean Energy Act*, BC Hydro is required to achieve electricity self-sufficiency by the year 2016 (i.e., F2017) by holding the rights to an amount of electricity that meets its electricity supply obligations, taking into account DSM and electricity "solely from electricity generating facilities within the Province". As a result of the self-sufficiency legal requirement, the following external market/import energy and capacity resources are not alternatives to the Project because they do not result "solely from electricity generating facilities within the Province":

- The spot market and imports from the U.S., Alberta, or other markets external to B.C. under long-term contract
- The Canadian Entitlement, which is the Canadian portion of the additional electricity produced in the Columbia River in the western U.S. as a result of provisions of the Columbia River Treaty of 1961, because the Canadian Entitlement is produced from electricity generating facilities in the U.S. and is delivered to the U.S.-B.C. border

5.4.2.2 Category 2: Supply-Side Resources Not Technically or Economically Feasible Alternatives

Coal-Fired Generation with Carbon Capture and Storage

Policy Action No. 20 of the 2007 Energy Plan stipulates that coal-fired generation in B.C. must meet a zero GHG emission standard "through a combination of 'clean coal' fired generation technology, carbon sequestration and offset for any residual GHG emission". While clean coal technology in the form of Integrated Gasification Combined Cycle is now becoming available, technology that allows plant-generated carbon dioxide (CO_2) to be captured and stored through sequestration is still evolving and is not presently viable on a commercial scale.

BC Hydro concludes that coal-fired generation with carbon capture and storage is not a technically feasible alternative to the Project. According to the Electric Power Research Institute (Electric Power Research Institute 2007), coal-fired generation plants with 90% CO_2 emission capture and storage could not be commercially available in B.C. until about 2028; this was also the conclusion of Powertech Lab Inc. (Powertech Labs Inc. 2009). There is uncertainty with respect to the cost of carbon capture and storage, and with respect to what impact carbon capture and storage will have on a large coal-fired generating station's efficiency. Although there are some geological sites in B.C. that may prove suitable for CO_2 storage, there is limited information available to assess the suitability for geological storage at this time. There are also a number of legal/regulatory and public acceptance issues that likely need to be addressed before carbon capture and storage technology can be considered on a commercial scale in B.C. For example, there is currently no liability regime in place to govern responsibility for CO_2 leakage once stored.

Wave

Wave energy is generated by winds blowing over the surface of the ocean. Currently, there are five generic approaches to capturing the wave energy resource, all of which are at the early stages of commercial development, with potential application in B.C. There are no wave energy projects in B.C. waters, although two demonstration projects received support from B.C. and Federal Government innovative clean energy funding agencies.

BC Hydro relied on information in the Geographic Information System map of the B.C. Integrated Land Management Bureau tenure database, and the incoming wave power from the Canadian Hydraulic Centre report (Canada Hydraulic Centre 2006) to develop the total theoretical wave energy potential. The costs associated with these wave energy projects have been estimated based on the cost projections from the U.K.-based Carbon Trust report (Carbon Trust 2006). A summary of the technical and financial results for wave resource is contained in Table 5.18.

Table 5.18 Summary of Wave Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($F2013/MWh)
North Coast	1	143	418	418	819
Vancouver Island	15	936	2,088	2,088	479 – 844
Total	**16**	**1,078**	**2,506**	**2,506**	**479 – 844**

BC Hydro concludes that wave energy is not an economically feasible alternative to Project. In comparison, the Project UEC excluding sunk costs is $94/MWh at the point of interconnection (POI) with the BC Hydro integrated system ($F2013; refer to Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate for details as to how the Project UEC is derived), and the Available Resource UECs are also well below the wave UEC range of $479/MWh to $844/MWh.

Tidal

Tidal energy refers to the energy available in the flow of water driven by the rotation of the earth in the gravitational fields of the sun and the moon. Tidal energy is variable from one hour to the next, but can be accurately predicted several years into the future. Tidal energy can be captured in two different ways – tidal barrages and tidal current systems. Tidal barrage is not considered a realistic prospect in B.C. due to its need for dam construction and its negative estuary ecosystem impact. This assessment focuses on tidal current systems. There are no commercial tidal current projects in B.C., although there are two demonstration projects underway.

Owing to the early state of commercial development, there is little real-world experience with the costs associated with tidal power on a commercial scale. BC Hydro relied on the Carbon Trust report described above in relation to wave resources to assess the costs of tidal development. A summary of the technical and financial results for tidal resource is contained in Table 5.19.

Table 5.19 Summary of Tidal Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($F2013/MWh)
Vancouver Island	12	617	1,426	1,426	275 – 605
Total	**12**	**617**	**1,426**	**1,426**	**275 – 605**

BC Hydro concludes that tidal is not an economically feasible alternative to Project. The Project UEC excluding sunk costs is $94/MWh at POI, and the Available Resource UECs are also well below the tidal UEC range of $275/MWh to $605/MWh.

Solar

Solar power is generated from sunlight and can be achieved directly using photovoltaic cells (crystalline silicon or thin film) or indirectly by using concentrating solar power technologies. Both technologies are commercially proven. Globally, the costs have achieved dramatic decline and are projected to continue to decline, but are not expected to become cost-competitive in Canadian jurisdictions over the next 10 years in the absence of price support. There are no known commercial solar power installations in

B.C. However, there are several distributed generation installations on the customer side of the meter.

The solar resource option assessment focuses on utility-scale photovoltaic systems given the ability to modularly increase the size of the solar power installation size over time and thereby managing capital investment risk. Concentrating solar power technologies are not included due to the large upfront capital investment as utility-scale concentrating solar powerplants typically require a large-scale implementation. The solar resource assessment examined commercial installations on the utility side of the meter with commercial scale solar installations sized at 5 MW. A summary of the technical and financial results for the solar resource is contained in Table 5.20.

Table 5.20 Summary of Solar Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($F2013/MWh)
Peace River	1	5	6	6	409
North Coast	1	5	5	5	437
Central Interior	1	5	6	6	463
Kelly/Nicola	1	5	6	6	412
Mica	1	5	6	6	432
Revelstoke	1	5	6	6	434
Vancouver Island	1	5	6	6	473
Lower Mainland	1	5	5	5	450
Selkirk	1	5	6	6	879
East Kootenay	1	5	6	6	382
Total	**10**	**50**	**57**	**57**	**382 – 879**

BC Hydro concludes that commercial solar is not an economically feasible alternative to Project, although solar generation will continue to be used on the customer side of the meter. In comparison, the Project UEC excluding sunk costs is $94/MWh at POI, and the Available Resource UECs are also well below the solar UEC range of $382/MWh to $879/MWh.

5.4.2.3 Category 3: DSM Options

Section 5.2.2.2 describes the BC Hydro DSM target, and Section 5.2.3 outlines BC Hydro's reliance on the current DSM target to fill the energy and capacity resource gaps and the delivery risk associated with the DSM target.

BC Hydro has developed a number of DSM options. BC Hydro's traditional DSM initiatives (the DSM target, and DSM Options 1 and 3) are expected to deliver both energy and capacity savings. The following section discusses the two additional, more aggressive DSM options that could deliver both energy and capacity, known as DSM Option 4 and DSM Option 5. BC Hydro also examined DSM options specifically designed to deliver capacity savings during BC Hydro's peak load periods on the electrical system through management and control of customers' electricity demand; refer to part 5.4.2.4.

DSM Options 4 and 5

BC Hydro concludes that DSM Options 4 and 5 are not viable alternatives to the Project because:

- DSM Options 4 and 5 present government and customer acceptance issues arising from BC Hydro's reliance on an aggressive and untested combination of rate structures, and codes and standards
- DSM Options 4 and 5 entail significant delivery risk, especially with respect to capacity savings, and could jeopardize BC Hydro's ability to serve its customers

DSM Option 4 targets about 9,500 GWh/year of energy savings and 1,500 MW of dependable capacity savings by F2021, and DSM Option 5 targets 9,600 GWh/year of energy savings and 1,600 MW of dependable capacity savings by F2021.

Acceptance

DSM Option 4 is founded on new or more aggressive conservation rate structures, and significant government intervention and regulation in the form of codes and standards, to generate additional savings. For example, all BC Hydro customers would be exposed to a much larger degree to marginal cost price signals, and rate structures may also need to be tied to a house or building's rated energy performance. Each industrial customer would need to meet a government mandated certified plant minimum efficiency level to take advantage of BC Hydro's Heritage hydroelectric lower priced electricity; otherwise, electricity would be supplied at marginal (market-based) rates. These tactics go well beyond the current DSM target, and would be new and untested. It is uncertain whether they would be accepted by government, customers, and the BCUC. DSM Option 4 also represents a bridge to DSM Option 5 by including activities and pilot initiatives that would facilitate the market and social transformations targeted by Option 5. As noted under DSM Option 5, these additional activities and initiatives would be new and untested, and it is uncertain to what extent they would succeed in generating additional electricity savings.

DSM Option 5 is the most aggressive DSM option that BC Hydro considered within the range of DSM resource options. DSM Option 5 aims to create a future scenario where buildings are net-zero consumers of electricity, with some buildings being net contributors of electricity back to the grid. Energy efficiency and conservation activities would be pervasive throughout society and ingrained in a business decision-making culture. This shift would be reflected through widespread district energy systems and micro-distributed generation, smaller and more efficient housing and building footprints, community densification, distributed workforce and "hotelling" (shared workspace), best practices in construction and renovation, efficient technology choices and behaviour, and an integrated community perspective (land use, zoning, multi-use areas). A carbon neutral public sector would contribute to the culture shift. For the industrial sector, a market transformation to certified plants would occur, supported with expanded regulation.

Option 5 includes a fundamental shift in BC Hydro's approach to saving electricity, one that places much greater emphasis on government regulation and rate structures to change market parameters and societal norms and patterns that influence electricity consumption and conservation. As a new and untested approach to saving electricity, Option 5 is subject to considerable uncertainty regarding government, customer, and

BCUC acceptance and, ultimately, its effectiveness at generating additional cost-effective electricity savings.

Delivery Risk

Delivery risk increases as the amount of reliance on DSM increases in a portfolio of DSM and supply-side resources. It is useful to contemplate delivery risk in terms of energy and capacity separately. A shortfall in energy could lead to the acquiring of more costly supply-side resources, such as IPP clean or renewable resources, in a compressed time frame, or could lead to an energy shortfall that could not be met through purchasing from the B.C. market, which could result in relying on imports to a greater extent than contemplated by the legal self-sufficiency requirements. While these are serious shortcomings, delivery risk is more of a critical problem on the capacity side, where a shortfall in electricity at key times would undermine BC Hydro's fundamental obligation to serve its customers' demand.

An unexpected departure from the mid-load forecast is of concern, particularly with respect to capacity planning. BC Hydro is relying on the current DSM target to deliver 1,400 MW of dependable capacity by F2021. The corresponding figures for DSM Options 4 and 5 are 1,500 MW and 1,600 MW, respectively, by F2021. There is significant uncertainty with respect to DSM capacity savings across all options, including the DSM target (refer to Section 5.2.3); moving to higher levels of DSM increases uncertainty around capacity savings.

BC Hydro has limited contingency resource options available on a relatively short timeline if DSM does not deliver the anticipated capacity savings. Natural gas-fired SCGTs (peaking units) of about 100 MW in size would be the principal potential B.C.-based capacity contingency resource. It is anticipated that SCGTs sited outside the Lower Mainland would take about five years for approval and construction. SCGTs above 50 MW trigger BCEAA and the requirement that the B.C. Minister of Energy, Mines and Natural Gas, and the B.C. Ministry of the Environment, authorize an EAC prior to construction. Constructing and operating SCGTs also requires Air Emissions Permits under the B.C. *Environmental Management Act*. There are social licensing issues associated with natural gas-fired generation, which are discussed in Section 5.5.2.8.

5.4.2.4 Category 4: DSM Capacity Initiatives

While DSM Options 4 and 5 discussed in Section 5.4.2.3 have associated capacity savings, additional capacity savings may be possible through DSM capacity activities (also referred to as peak reduction or peak shaving). Capacity-focused DSM savings were grouped into two broad categories:

- Industrial load curtailment: This DSM option targets large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods. BC Hydro has implemented a load curtailment program targeted at shorter term (one to three years) capacity needs in recent years, and customers have delivered as requested. However, it is not clear how easily these can be translated into long-term agreements that can reliably reduce peak demand over the long-term when needed.
- Capacity programs: This DSM option contains programs that leverage equipment and load management systems to enable peak load reductions to occur

automatically or with intervention. Programs may involve payment for customer equipment and a financial payment for participation in the program. Examples of capacity programs include load control of water heaters, heating, lighting, and air conditioning. Thus capacity-focused programs are a collection of several activities; both demand response and load control, spread across different customer classes. The participation rates and savings per participant are key aspects of the uncertainty of capacity savings.

An attempt to assess the range of outcomes with respect to industrial load curtailment and DSM capacity programs for a selected year is shown in Table 5.21.

Table 5.21 Savings From Capacity DSM and Uncertainty

(MW in F2021)	Industrial Load Curtailment	Capacity-Focused Programs
Low (P10 cut-off)	316	135
Mid (mean or expected)	382	193
High (P90 cut-off)	443	256

There are a number of uncertainties regarding DSM capacity initiatives that are not well understood. Since BC Hydro is just starting to develop long-term DSM capacity savings options, implementation success is an important issue. In particular, precise program initiation dates and customer participation rates are unknown; BC Hydro would want to test both of these drivers through pilot initiatives. Once these approaches are established, operational experience will still be required to understand how participation and savings per participant translate into peak shaving. Similarly, experience will be needed to see how savings for each initiative translates into peak reduction for the entire system – whether these peaks are coincident with peak load and whether peak shaving leads to other system peaks.

BC Hydro concludes that DSM capacity options are not viable alternatives to the Project, given the number of significant uncertainties underlying such DSM initiatives described above.

5.5 Available Resources

This section describes and compares the available resources using financial, technical, environmental, and economic development decision attributes. As set out in Section 5.4.1.1, the available resources are:

- Clean or renewable energy resources from third parties: wind – both on-shore and off-shore, run-of-river hydro, geothermal, and biomass
- BC Hydro Resource Smart energy and capacity resources
- A clean or renewable capacity resource: pumped storage
- Natural gas-fired generation and cogeneration, including energy resource CCGTs and capacity resource SCGTs, within the 93% *Clean Energy Act* clean or renewable target described in Section 5.5.2.8

The comparison consists of 1) an overview of the attributes of each individual available resource, provided in Section 5.5.2, and 2) portfolio analysis, the results of which are set out in Section 5.5.4. Portfolios are combinations of different mixes of available resources to meet the Project's 5,100 GWh/year of firm energy and 1,100 MW of dependable

capacity. Thus these portfolios constitute the economically and technically feasible alternatives to the Project.

The remainder of this section is organized as follows:

- Section 5.5.1 describes the financial, technical, environmental, and economic development decision attributes
- Section 5.5.2 provides descriptions of the available resources, including the UECs and Unit Capacity Costs (UCCs) as applicable, and a summary of the key uncertainties and risks of each available resource. Section 5.5.2.8 sets out the *Clean Energy Act*'s 93% clean or renewable target, and the resulting permissible natural gas-fired generation in both GWh and MW for selected years. The result is that, on its own, natural gas-fired generation is not an alternative to the Project because there is not enough space, given the 93% clean or renewable target for natural gas-fired generation, to provide 5,100 GWh/year of firm energy and 1,100 MW of dependable capacity; rather, natural gas-fired generation must be combined with clean or renewable resources. This is done in the portfolio analysis in Section 5.5.4.
- Section 5.5.3 sets out the modelling and portfolio process
- Section 5.5.4 presents the expected costs and risk performance of the different portfolios with and without the Project across different future scenarios
- Section 5.5.5 summarizes the available resources assessment

5.5.1 Measurement Criteria: Attributes

Attributes are the measurement criteria by which impacts of resource alternatives are measured. There are several reasons why BC Hydro considered a broad set of attributes for purposes of the EIS:

- The Agency Need/Alternatives Policy Statement (CEA Agency 2007) states that "the major environmental, economic and technical costs and benefits" should be identified and described
- The EIS Guidelines provide that BC Hydro will describe the major financial, technical, environmental, and economic development attributes of the supply-side alternatives to the Project
- The *Clean Energy Act* stipulates that BC Hydro must carry out resource development consistent with good utility practice; this includes understanding the broader implications of BC Hydro's planning actions
- As part of the IRP and Project-related First Nations and public engagement processes, BC Hydro found that First Nations and the public are interested in a broad set of effects beyond financial impacts
- As described in Section 5.3, the B.C. Government explicitly laid out a number of objectives in the *Clean Energy Act*. These objectives include a mix of financial and non-financial considerations, including a focus on clean or renewable electricity and GHG emissions. Refer to Table 5.22.

Table 5.22 *Clean Energy Act* and Other Objectives and Attributes

Decision Objective and Attribute	Reason for Inclusion
Minimize Financial Impacts: ▪ Cost ▪ Cost risk	Good utility practice; First Nations, public and stakeholder interests; congruent with *Clean Energy Act* objectives
Minimize Environmental Footprint, Including: ▪ Land footprint ▪ Water footprint ▪ Criteria air contaminants ▪ GHG emissions	Good utility practice; First Nations, public and stakeholder interests; congruent with *Clean Energy Act* objectives
Maximize Economic Development	First Nations, public and stakeholder interests; congruent with *Clean Energy Act* objectives

These attributes are considered at a provincial level, as data do not exist at a regional or local level for all projects (in many cases, generation resources are represented as a "typical" project or block of projects). In addition, the resources selected through portfolio modelling are not necessarily the ones that would be selected through an actual acquisition process.

5.5.1.1 Financial Attributes

Financial attributes describe the cost of resource options. The *Clean Energy Act* and good utility practice underscore the importance of tracking costs when comparing resource options. The financial implications of the supply-side resource options or strategies to fill the load-resource gap are tracked at a portfolio level as set out in Section 5.5.4, which provides the portfolio results, both for the cost of acquiring new resources and for how these resources interact with the existing system and the external electricity market.

Financial attributes considered include:

- UEC: reflects the real levelized cost (as described in Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate) of a unit of energy from a resource option or portfolio (typically in $F2013/MWh). The values serve as an initial ranking of energy resources in scheduling resources to fill a load/resource gap.
- UCC: reflects the real levelized cost of a unit of capacity from a resource option (typically in $F2013/kW-year). UCCs are calculated by taking the levelized annual cost of a capacity resource divided by the resource's dependable capacity.

Some key assumptions or methods of determination used to develop the financial attributes include:

- Point of Interconnection (POI): Unless otherwise stated, resource options costs are presented as UECs and UCCs at POI. The costs at POI represent the estimated overall cost of both non-firm and firm energy, and are based on the sum of three component costs: costs within plant gate, road costs (linking plant gate area to existing road infrastructure), and transmission interconnection costs. The costs at POI do not reflect the additional costs of delivering resources to the Lower Mainland (BC Hydro's major load centre) and of firming and integrating intermittent clean or renewable resources. While these are important cost considerations, they are

factored in at the portfolio analysis stage described in Section 5.5.3. GHG offset-related and fuel costs are included in the UECs/UCCs for natural gas-fired generation.

- Escalation: The UECs and UCCs are presented in constant dollars as of January 1, 2013 ($F2013). A 2% inflation factor is used in instances where it was necessary to inflate dollar values to $F2013.
- Weighted average cost of capital: An 8% real cost of capital rate is used in determining UECs and UCCs for available resources. Pursuant to Policy Action #13 of the 2002 Energy Plan, IPPs are to develop all resources other than DSM, Resource Smart and the Project, and IPPs have a higher cost of capital than BC Hydro. BC Hydro's weighted average cost of capital is 5.5%; a rounded 6% cost of capital is used for the Project UECs. Refer to Section 5.5.3 for further detail.

All of the available resources have more cost uncertainty than the Project because they are feasibility- or conceptual-level estimates only. The cost estimates for available resources are generally a Class 4 (feasibility, fairly wide accuracy range, typically used for alternative evaluation) or a Class 5 (concept screening, wide accuracy range) degree of accuracy. In addition, the available resource cost estimates do not reflect site-specific information; on-the-ground assessments tend to increase cost estimates. In contrast, the Project cost estimate of $7.9 billion has a Class 3 (budget authorization or control) degree of accuracy, as defined by the Association for the Advancement of Cost Engineering (AACE 2012). Refer to Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate for additional detail. A Class 3 degree of accuracy is consistent with the BCUC's requirements for project cost estimates set out in the BCUC 2010 Certificate of Public Convenience and Necessity Application Guidelines.

The Project cost estimate of $7.9 billion (nominal dollars) contains cost allowances for mitigation, regulatory review, First Nation consultation, and public engagement. Implementation of the available resources would also entail mitigation, regulatory review, First Nation consultation, and public engagement costs (referred to as 'soft costs'), but it is not possible to precisely quantify such soft costs, as it is difficult to predict the outcome of consultation/engagement or to identify the costs of such processes or the costs of mitigation requirements that may be imposed following these processes, not least because different First Nations and stakeholders may have conflicting goals and requirements. Accordingly, while the available resource costs set out in Section 5.5.2 do not include such costs, BC Hydro has put a cost adder of 5% on available resource portfolios to reflect the fact that implementing any of the available resource options would trigger soft costs. Refer to Section 5.5.3 for greater detail.

5.5.1.2 Technical Attributes

Technical attributes describe the energy and capacity that each available resource provides and are used to assemble portfolios that meet BC Hydro's energy and capacity reliability planning criteria. The technical attributes considered for resource options are:

- Dependable generating capacity (DGC), which is used for non-intermittent resources, is the amount of MW that a plant can reliably produce when required, assuming all units are in service
- ELCC, which is used for intermittent or variable generation resources, is the maximum peak load (MW) that a generating unit or a system of units can reliably

supply, such that the loss of load expectation will be no greater than one day in 10 years. Refer to Section 5.2.1.2 for a description of ELCC shortcomings.

- Installed (nameplate) capacity (MW)
- Firm energy load-carrying capability (FELCC) is the maximum amount of annual energy that a hydroelectric resource can produce under critical water conditions and is measured in GWh/year
- Average annual energy (GWh/year)
- Hourly/daily/monthly variability

A summary of the generation reliability assumptions and methods of development is presented in Table 5.23.

Table 5.23 Generation Reliability Assumptions and Methods

Potential Generation Resources	DGC and ELCC Assumptions and Methods of Determination (MW)	FELCC Assumptions and Methods of Determination (GWh/year)
Run-of-river	ELCC: Weighted average of approximately 60% of the forecasted average MW of potential in the December/January period	Region-specific factors applied to the average annual energy; monthly variability
Biomass	DGC: 100% of installed capacity for wood-based biomass; 97% of installed capacity for municipal solid waste; and 95% of installed capacity for biogas	100% of average annual energy
Wind – onshore	ELCC: 24% of installed capacity	100% of average annual energy; hourly and daily variability
Wind – offshore	ELCC: 24% of installed capacity	100% of average annual energy; hourly and daily variability
Geothermal	DGC: 100% of installed capacity	100% of average annual energy
Natural gas-fired generation & cogeneration	DGC: Varies from 88% to 100% of installed capacity	Based on 18% capacity factor for SCGTs and 90% for CCGTs
Project	DGC: 1,100 MW	4,700 GWh/year (average energy is 5,100 GWh/year)
Pumped storage	DGC: 100% of installed capacity	N/A (consumes energy)

NOTE:

[a] Capacity factor of an electricity generating facility is the ratio of the actual output of the electricity generating facility over a period of time and its potential output if it had operated at full installed capacity over the entire period; natural gas-fired generation is relied upon to run a minimum of 18% of the time for its energy contribution

BC Hydro uses reliability planning criteria for planning purposes to evaluate when generation resources are required to maintain an adequate supply of electricity resources to reliably meet customer demand. BC Hydro considers both the peak load (generation capacity reliability planning criterion) and annual energy demand (generation energy reliability criterion) on its electrical system. With respect to energy, from a BC Hydro planning perspective:

- Heritage hydroelectricity facilities, including the Project, are relied on for their average energy contribution, as shown in Table 5.23, as a result of the Electricity

Self-Sufficiency Regulation, which mandates that BC Hydro use the average water capability of its heritage hydroelectric resources

- Available resources developed by IPPs or other third parties are relied on for their firm energy contribution. The Electricity Self-Sufficiency Regulation is silent on IPP energy output and, accordingly, BC Hydro uses its energy reliability criterion. Non-firm energy from IPPs does not contribute to BC Hydro's energy reliability criterion.

As described below in Section 5.5.2, run-of-river and wind resources provide very little dependable capacity. For example, run-of-river and wind resources made up virtually all of the 25 EPAs awarded pursuant to BC Hydro's most recent power acquisition process, the Clean Power Call. While these resources are to provide over 3,000 GWh/year of firm energy, they only provide 9 MW of dependable capacity.

5.5.1.3 Environmental Attributes

Environmental attributes provide high level information on the footprint of the available resources. BC Hydro retained Kerr Wood Leidal Associates Ltd., Hemmera Envirochem Inc. and HB Lanarc to develop the environmental attributes. The environmental attributes were selected based upon the following criteria:

- Appropriate for provincial-scale portfolio comparisons
- Science-based and defendable
- Measurable in a "quantity"-based approach that facilitates comparison between portfolios of available resources
- Representative of relevant biophysical resources
- Based on existing data or easily acquired data
- Easy to understand for long-term planning and stakeholder engagement purposes

The environmental attributes are grouped into four environmental categories: land, atmosphere, freshwater, and marine, and are further broken down into indicators, as described in Table 5.24.

Table 5.24 Environmental Attributes

Environmental Category	Indicator	Unit of Measure	Classifications
Land	Net primary productivity ($gC/m^2/year$) [a]	hectares (ha) per class	Low (0 to < 69)
			Medium (69 to < 369)
			High (> 369)
	Remoteness – linear disturbance density (km/km^2)	ha per class	Wilderness (< 0.2)
			Remote (0.2 to < 0.66)
			Rural (0.66 to 2.2)
			Urban (> 2.2)
	High priority species count (percentile)	ha per class	0 to < 20
			20 to < 40
			40 to < 60
			60 to 80
			> 80
Atmosphere	GHG emissions	tonnes/GWh	Carbon dioxide equivalent (CO_2e)
	Air contaminant emissions	tonnes/GWh	Sulphur dioxide
			Oxides of nitrogen (NO_x)
			Carbon monoxide
			Volatile organic compounds
			Fine particulates (PM): $PM_{2.5}$ (reported when data are available)
			Fine particulates: PM_{10} (reported when data are available)
			Fine particulates: PM total
			Mercury
Freshwater [b]	Reservoir aquatic area	ha	Site C Clean Energy Project only (while pumped storage and resource smart may create reservoir aquatic areas, these have only been described qualitatively in Section 5.5.2, as the calculations were not done for the 2010 Resource Options Report)
	Affected stream length	kilometres (km)	Run-of-river and the Site C Clean Energy Project (pumped storage and Resource Smart if applicable/available)
	Priority fish species (number of priority fish [c] species per watershed)	ha per class	No priority species (0)
			Low species diversity (1 to 12)
			Moderate species diversity (13 to 23)
			High species diversity (24 to 38)

Environmental Category	Indicator	Unit of Measure	Classifications
Marine [d]	Valued ecological features (number of valued ecological features)	ha per class	None (0)
			Low (1 to 2)
			Medium (3 to 5)
			High (> 5)
	Key commercial bottom fishing areas	ha per class	No bottom fisheries
			1 bottom fishery
			2 to 3 bottom fisheries
			> 3 bottom fisheries

NOTES:

[a] $gC/m^2/year$ = grams of carbon per square metre per year; this indicator is a proxy for how much annual vegetation growth occurs in an area per year

[b] The 2010 Resource Options Report developed a fourth freshwater attribute to address the riparian footprint. This attribute was subsequently dropped due to lack of data for potential run-of-river sites and pumped storage, which would have made the comparisons ineffectual.

[c] Priority fish are those that have been identified for conservation in the province of B.C. through the B.C. Conservation Framework, and then filtered to ensure native species and provincial range data

[d] The 2010 Resource Options Report developed a third marine attribute of bathymetry, which is a descriptor of water depth. This attribute was subsequently not reported, given that it added negligible value compared with the other two marine attributes.

Refer to Section 5.5.2 for a description of the environmental attributes of individual Viable Alternatives.

5.5.1.4 Economic Development Attributes

Economic development attributes describe the contributions that the available resources make to the provincial economy. The economic development attributes selected are categorized into three groups: provincial GDP, employment, and Provincial Government revenue, and are further broken down into sub-categories described in Table 5.25. The British Columbia Input-Output Model was used to determine the economic development attributes, using a methodology and definitions similar to that in Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impact: BC Stats.

Table 5.25 Economic Development Attributes

Economic Development Category	Sub-Category	Unit of Measure	Classifications
Provincial GDP	Construction/Operation	Dollars ($) and $/year	Direct
			Indirect
			Induced
Employment	Construction/Operation	Jobs	Direct
			Indirect
			Induced
Provincial Government revenue	Construction/Operation	$ and $/year	Direct
			Indirect
			Induced

5.5.2 Description of Available Resources

This section presents an overview of the available resources. The available resource potential is screened only to remove sites from consideration if they were located in an

area where there would be legal or regulatory prohibitions; therefore, this results in a large volume of potential energy and dependable capacity with a wide range of costs, which may or may not be developed in the future. At a high level, this section is organized according to energy-rich available resources, followed by capacity-rich available resources. Technical and financial results are presented for each resource option where UECs and UCCs are shown at the POI. The summarized attributes of portfolios are examined in the portfolio analysis in Section 5.5.4. Resource option data are reported by BC Hydro transmission region where the interconnection to the BC Hydro integrated system occurs.

For comparison purposes, the UEC of the Project excluding sunk costs is about $94/MWh at POI ($F2013). See Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate with respect to the calculation of the Project's UEC.

5.5.2.1 Run-of-River Hydroelectricity

A run-of-river hydroelectric generation facility diverts a portion of natural stream flows and uses the natural drop in elevation of a river to generate electricity. Run-of-river projects divert some of a river's flow for power generation and leave the remaining flow in the original stream. A weir (i.e., a structure smaller than a dam used for storage hydro) is required to divert flows into the pipelines (referred to as penstocks) that lead to the power generation facility turbines. A run-of-river project either has no storage at all, or a limited amount of storage, in which case the storage reservoir is referred to as pondage. Some of the run-of-river generation facilities proposed and/or canvassed in the 2010 Resource Options Report rival traditional large hydroelectric facilities in scale and installed capacity. The expected life of run-of-river projects is about 50 years, with the maximum water licence term being 40 years. To date, BC Hydro run-of-river EPAs have typically had terms of between 30 to 40 years.

Environmental Attribute Overview: Hydroelectricity is a clean or renewable resource as defined by Section 1 of the *Clean Energy Act*. Run-of-river projects have a number of environmental impacts, the most important of which is the impact to fish and aquatic ecosystems. Diverting river water can reduce river flows, affecting water velocity and depth, and potentially affecting habitat quality for fish and aquatic organisms. New access roads and transmission lines can cause habitat fragmentation for many species, introduce invasive species, and increase human activities such as illegal hunting. There may also be recreational impacts.

Technical and Financial Attribute Overview: Run-of-river electricity is an intermittent source of energy with low amounts of dependable capacity because such facilities have little or no storage, and hence output is subject to seasonal river flows and cannot be co-ordinated to match customer demand. Run-of-river hydroelectric facilities generate more energy during times when seasonal river flows are high, such as the spring freshet, which coincides with reduced demand and low electricity prices in external markets. Generation drops during low flow periods. Figure 5.5 shows the power output of a typical run-of-river project in BC Hydro's Lower Mainland/South Coast region.

Typically, the output from run-of-river projects is not predictable outside the spring freshet and cannot be regulated to match demand. Refer to Section 7.4.3 in Volume 1 Section 7 Project Benefits for a discussion of how integrating variable available resources such as run-of-river and wind generation into the BC Hydro system requires

backup dispatchable capacity such as large hydroelectricity (the Project) or natural gas-fired generation.

The 2010 Resource Options Report for run-of-river resources was undertaken in collaboration with Kerr Wood Leidal. The study used a Geographical Information System tool to assess the energy, capacity, and cost of selected potential run-of-river generating sites. A summary of the technical and financial results for run-of-river is contained in Table 5.26.

Table 5.26 Summary of Run-of-River Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
Peace River	14	83	1	250	215	436 – 600
North Coast	315	2,330	117	8,527	6,965	97 – 600
Central Interior	50	566	32	2,100	1,660	157 – 595
Kelly/Nicola	145	931	50	3,429	2,701	98 – 599
Mica	116	769	21	2,675	2,359	136 – 595
Revelstoke	139	786	30	2,796	2,431	110 – 596
Vancouver Island	395	2,709	502	10,778	8,237	105 – 599
Lower Mainland	187	1,599	245	6,829	5,177	82 – 599
Selkirk	80	568	10	1,886	1,641	128 – 599
East Kootenay	150	790	11	2,593	2,232	109 – 599
Total	**1,591**	**11,130**	**1,018**	**41,866**	**33,619**	**82 – 600**

NOTE:
The table presents results for run-of-river resources under $600/MWh

Historically, some of the run-of-river resource options with the lowest unadjusted UEC values have not always bid into BC Hydro's power acquisition processes. BC Hydro examined the results of its two most recent broadly-based power acquisition processes, the 2009 Clean Power Call and the F2006 Call. The Clean Power Call is considered to be the best comparator derived from BC Hydro's power acquisition processes, given that it reflects the most recent BC Hydro power acquisition process pricing, and a large volume and broad array of clean, renewable technologies, including both hydro-based and wind-based projects. The Clean Power Call was open to any form of clean or renewable energy (excluding wood-based biomass, which was subject to a separate call for power), with 25 EPAs awarded in the spring/summer of 2010 for a total of 3,266 GWh/year of firm energy. Run-of-river projects made up about 50% of EPAs awarded pursuant to the 2009 Clean Power Call (by firm energy) and dominated the F2006 Call, the second most recent BC Hydro broadly based power acquisition process:

- The Clean Power Call weighted average levelized price is $109/MWh at plant gate ($F2013)
- The F2006 Call was undertaken over six years ago, resulting in a weighted average levelized adjusted plant gate price for large projects of about $86/MWh ($F2013)

5.5.2.2 Onshore Wind

Wind power refers to the conversion of energy from moving air into electricity. Modern utility-scale wind turbines are horizontal axis machines with three rotor blades. The blades convert the linear motion of the wind into rotational energy that is then used to drive a generator. Onshore wind is considered a mature technology; see, for example,

Energy + Environmental Economics report (Energy + Environmental Economics 2012). The expected life of wind projects is about 20 to 25 years, although a recent British study concluded that the economic life of onshore wind turbines is between 10 and 15 years (Renewable Energy Foundation 2012). A shorter wind resource economic life would raise the per unit cost of energy produced (MWh). To date, BC Hydro wind EPAs have typically had terms of between 20 to 25 years.

Environmental Attribute Overview: Wind is a clean or renewable resource, as defined by Section 1 of the *Clean Energy Act*. Wind resources do not use combustion to generate electricity and hence do not produce air emissions. Concerns have been raised over the noise produced by the rotor blades (in recent years, engineers have made design changes to reduce the noise from wind turbines), visual impacts (because wind energy resources are generally sited in exposed places, wind turbines are often visible), and deaths of birds and bats that fly into the rotors. Footprint impacts can also include new access roads and transmission lines.

Technical and Financial Attribute Overview: Wind generation resources can have highly variable output over a time frame of minutes, hours, and days. Figures 5.6 and 5.7 show a sample wind resource generation profile over a sample eight-day period in June 2011 and January 2012, respectively.

Due to this variability and the difficulty of accurately forecasting wind energy output, wind resources that are acquired by BC Hydro will result in new operating requirements and procedures. While BC Hydro has a large, flexible hydroelectric-based generation system that can manage this variability, the total system flexibility is limited. As a result, there are costs associated with managing wind variability that need to be recognized. Adding wind resources will require the carrying of appropriate additional reserves to compensate for sudden fluctuations in wind power in three different planning horizons: 1) regulation (minute to minute), 2) load following (minutes to hours), and (3) unit commitments/scheduling (hours to days). BC Hydro estimates that the wind integration cost is about $10/MWh generated. This total wind integration cost estimate is slightly higher than that used by Manitoba Hydro, but is comparable to the total wind integration cost estimates proposed by Hydro Quebec, the U.S. Pacific Northwest electric utility PacifiCorp, and the Bonneville Power Administration. The $10/MWh wind integration cost is not reflected in the UEC values set out in Table 5.27 below, but is included in the portfolio analysis in Section 5.5.4.

For the 2010 Resource Options Report, BC Hydro engaged DNV Global Energy Concepts Inc. to complete the Wind Data Study and Wind Data Study Update to obtain detailed information on the wind resource potential in B.C., and engaged Garrad Hassan to update the onshore wind costs. As noted above in Section 5.4.1.2, the 2010 Resource Options Report wind UECs have been revised (lowered) to take into account the changes in turbine efficiencies and wind turbine prices that have occurred over the past three years. A summary of the technical and financial results for onshore wind is contained in Table 5.27 using the revised wind costs. For comparison purposes, the average levelized plant gate cost of the approximately 50% of EPAs awarded for wind projects (by firm energy) through the Clean Power Call is $108/MWh ($F2013).

Table 5.27 Summary of Onshore Wind Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI [a] ($F2013/MWh)
Peace River	45	5723	1374	17778	17778	96 – 315
North Coast	23	4016	964	11025	11025	120 – 332
Central Interior	9	1132	272	2892	2892	130 – 234
Kelly/Nicola	22	3489	837	8886	8886	130 – 176
Revelstoke	4	644	155	1674	1674	126 – 154
Vancouver Island	13	1111	267	3143	3143	120 – 216
Lower Mainland	1	90	22	249	249	146
Selkirk	2	83	20	194	194	144 – 236
East Kootenay	2	138	33	324	324	147 – 157
Total	**121**	**16,425**	**3,942**	**46165**	**46,165**	**96 – 332**

NOTE:
[a] The UECs shown do not include a wind integration cost adder of about $10/MWh

5.5.2.3 Offshore Wind

In addition to onshore wind potential, BC Hydro examined the potential of offshore wind turbines located in ocean substrate depths of up to 40 m. Onshore and offshore wind assessments are undertaken separately because of the differences in methodologies used to assess the resource potential, as well as differences in the financial cost assumptions.

Technical and Financial Attribute Overview: The analysis is based on averaged wind speeds at 80 m hub height from the Canadian Wind Atlas, and gridded bathymetric data provided by the Canadian Hydrological Services. Modelled wind speeds from the Canadian Wind Atlas were compared to long-term wind speed estimates based on actual offshore observations. Garrad Hassan provided representative costs for offshore wind projects as a function of water depth. A summary of the technical and financial results for offshore wind are contained in Table 5.28.

Table 5.28 Summary of Offshore Wind Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
North Coast	36	12,873	3,090	41,991	41,991	208 – 734
Vancouver Island	7	2,466	592	8,270	8,270	190 – 279
Total	**43**	**15,339**	**3,681**	**50,261**	**50,261**	**190 – 734**

5.5.2.4 Wood-Based Biomass

Wood-based biomass electricity is generated from the combustion or gasification of organic materials as fuels. In developing the potential of wood-based biomass, the following categories of fuels were considered:

- Standing timber (including wood killed by mountain pine beetles)

- Roadside wood waste (wood already harvested, but left in the forest or on the roadside; some is wood killed by mountain pine beetles)
- Sawmill wood waste

To date, BC Hydro bioenergy EPAs have typically had terms of between 10 to 15 years.

Environmental Attribute Overview: Biomass is a clean or renewable resource, as defined by Section 1 of the *Clean Energy Act*. Combustion of biomass produces local air contaminants such as particulate matter and oxides of nitrogen. The amount of carbon dioxide released when biomass is burned is nearly the same as the amount required to replenish the plants grown to produce the biomass. Thus, in a sustainable fuel cycle, there would be no net emissions of carbon dioxide, although some fossil-fuel inputs may be required for planting, harvesting, transporting, and processing biomass. Footprint impacts can also include new access roads and transmission lines. The environmental attributes used in the portfolio analysis only include the footprint for the facility site – the footprint for fuel harvesting is not included.

Technical and Financial Attribute Overview: BC Hydro engaged consultants from Industrial Forest Services Ltd., together with industry experts, to conduct a modelling study to estimate the long-term energy potential, costs, and possible locations for wood-based biomass projects. Overall, the study found that the amount of standing timber available for fuel was forecast to decline significantly over the next 15 years, but then stabilize after that. In addition, the study identified the availability of significant volumes of roadside and sawmill wood waste, but indicated that there was uncertainty regarding the actual potential that could be realized.

Generally, when a secure fuel supply contract is in place, the installed capacity of wood-based biomass projects is considered dependable, and the annual energy production is considered firm. Biomass is generally not dispatchable.

A summary of the technical and financial results for wood-based biomass is presented in Table 5.29. BC Hydro has undertaken two wood-based biomass power acquisition processes, resulting in the following pricing:

- Bioenergy Phase I Call Request for Proposals (RFP) (2008/2009) with a levelized plant gate firm energy price of $111/MWh ($F2013). The Bioenergy Phase I Call RFP resulted in four EPAs for a total of 579 GWh/year of firm energy.
- Bioenergy Phase II Call RFP (2010/2011) with a levelized plant gate firm energy price of $123/MWh ($F2013). The Bioenergy Phase II Call RFP resulted in a total of 754 GWh/year of firm energy.

Table 5.29 Summary of Wood-Based Biomass Potential

Transmission Region	Number of Potential Sites*	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
Standing Timber						
Peace River	2	112	112	892	892	175 – 232
North Coast	4	201	201	1,602	1,602	165 – 985
Kelly/Nicola	1	25	25	201	201	172
Vancouver Island	1	358	358	2,850	2,850	185
Lower Mainland	1	358	358	2,850	2,850	185
Selkirk	1	4	4	29	29	180
East Kootenay	1	3	3	23	23	167
Subtotal	11	1,060	1,060	8,447	8,447	165 – 985
Roadside Debris & Wood Waste						
Peace River	1	31	31	248	248	141
North Coast	3	89	89	707	707	130 – 143
Central Interior	1	31	31	244	244	139
Kelly/Nicola	1	51	51	408	408	144
Vancouver Island	1	80	80	641	641	125
Lower Mainland	1	80	80	641	641	129
Selkirk	1	39	39	312	312	137
East Kootenay	1	37	37	298	298	141
Subtotal	10	439	439	3,499	3,499	125 – 144
Total	**21**	**1,499**	**1,499**	**11,946**	**11,946**	**125 – 985**

NOTE:
For wood-based biomass, this reflects the number of fibre delivery locations considered in the study. The capacity figures shown reflect the total potential power generation (using multiple plants) based on the estimated fuel supply. In general, there is one fibre delivery location assumed for each forestry sub-region unless the potential is small.

Wood-based biomass is considered further in the portfolio analysis. The only exception is the standing timber portion of wood-based biomass, which has been excluded due to cost and other uncertainty.

5.5.2.5 Biomass – Municipal Solid Waste

Municipal solid waste biomass refers to the conversion of municipal solid waste into a usable form of energy, such as electricity. Conventional combustion and gasification are the most commonly used municipal solid waste technologies. The municipal solid waste resource option potential is estimated based on fuel source availability, where an attempt was made to incorporate the zero waste philosophy that endeavours to minimize the amount of waste going to landfills by employing waste avoidance and diversion strategies. A summary of the technical and financial results for municipal solid waste is contained in Table 5.30.

Table 5.30 Summary of Municipal Solid Waste Biomass Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
Vancouver Island	1	12	12	101	101	194
Lower Mainland	1	34	33	285	285	117
Selkirk	1	14	13	112	112	259
Total	**3**	**60**	**58**	**499**	**499**	**117 – 259**

5.5.2.6 Biomass – Biogas or Landfill Gas

Landfill gas is created when organic waste in a municipal solid waste landfill decomposes under anaerobic conditions. Landfill gas can be captured, converted, and used as an energy source to help prevent methane from migrating into the atmosphere and contributing to global climate change. Technologies for producing electricity from landfill gas include internal combustion engines, gas turbines, and micro turbines.

In developing the landfill gas resource potential, BC Hydro reviewed a report by Golder (Golder 2008). A summary of the technical and financial results for biogas is presented in Table 5.31.

Table 5.31 Summary of Biogas Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
Central Interior	1	2	2	17	17	71
Kelly/Nicola	2	4	4	33	33	73 – 106
Vancouver Island	3	2	2	19	19	70 – 159
Lower Mainland	3	4	4	32	32	60 – 96
Selkirk	3	4	4	33	33	73 – 96
Total	**12**	**17**	**16**	**134**	**134**	**60 – 159**

Biogas is not included in the portfolio analysis in Section 5.5.4 because there has been only one biogas project with a small volume of energy bid into a 2003 BC Hydro power acquisition process, resulting in two EPAs.

5.5.2.7 Geothermal

Geothermal energy systems draw on natural heat from within the earth's crust to drive conventional power generation technologies. The primary source of geothermal energy is radioactive decay occurring deep within the earth, supplemented by residual heat from the earth's formation and heat generated by earth's gravitational forces pulling dense materials into the earth's core.

Geothermal electricity can be produced based on conventional or unconventional resources. Conventional resources are in the form of high or medium temperature steam or hot water associated with geological structures that bring heat relatively close to the earth's surface. Only conventional hydrothermal resources using flash or binary technologies are considered within BC Hydro's resource option assessment. There may be potentially significant unconventional resources that could increase the potential

geothermal resource base of B.C., including hot dry rock or low temperature hydrothermal resources in the sedimentary basin.

Environmental Attribute Overview: Geothermal is a clean or renewable resource, as defined by Section 1 of the *Clean Energy Act*. Geothermal resources can have an effect on groundwater flow. Footprint impacts can include new access roads and transmission lines.

Technical and Financial Attribute Overview: BC Hydro reviewed a number of external studies to develop its assessment of geothermal potential. A summary of the technical and financial results for the geothermal resource option is contained in Table 5.32. The geothermal cost estimates are based on generic capital and operating/maintenance costs using U.S. industry experience, with an adjustment for climate and topography in B.C. These values do not account for a relatively higher exploration risk that is expected for B.C. greenfield geothermal resources. Development of greenfield geothermal resources is associated with a relatively higher rate of drilling program failure in the exploration stage, which can add to the development costs and the UEC of a given project, especially for smaller projects. Due to this expected higher exploration risk and the higher costs associated with failed exploration wells of B.C. resources relative to the generic U.S. industry average, the estimates shown are likely to be low.

Table 5.32 Summary of Geothermal Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
Peace River	1	20	20	140	140	119
North Coast	3	270	270	2,111	2,111	90 – 121
Kelly/Nicola	1	20	20	140	140	125
Revelstoke	1	20	20	140	140	127
Vancouver Island	2	70	70	534	534	132 – 581
Lower Mainland	5	320	320	2,505	2,505	88 – 124
Selkirk	3	60	60	420	420	118 – 166
Total	**16**	**780**	**780**	**5,992**	**5,992**	**88 – 581**

NOTE:
The summary table excludes two sites that are technically inaccessible (e.g., within a protected area or within an area that exceeds technical criteria established for road or transmission access)

B.C.'s geothermal resource is estimated to total more than 700 MW of potentially cost-effective clean or renewable power. However, BC Hydro has not included the geothermal resource option in the portfolio analysis in Section 5.5.4 for the following reasons:

- As described above in Section 5.5.2.1, historically, resource options with the lowest unadjusted UECs values have not always bid into BC Hydro's power acquisition processes. Despite its relatively low cost (an unadjusted UEC of $88/MWh in $F2013), geothermal resource developers have never bid into BC Hydro's power acquisition processes. From the 2010 Resource Options Report, BC Hydro understands that there are some challenges with geothermal development in B.C. related to the risk/reward of making a significant upfront capital investment at the early exploration and initial production drilling stages.

- There are no commercial geothermal electricity projects in B.C. at this time. Since 2002, the B.C. Ministry of Energy, Mines and Natural Gas has released geothermal permits to developers at 12 locations in the province, but these have not resulted in any significant investments in exploration. The only significant private sector investment in exploration was led by Sierra Geothermal (now Ram Power) in 2004 at South Meager Creek; however, the multi-million dollar drilling program failed to yield geothermal wells useful for geothermal power production.

5.5.2.8 Natural Gas-Fired Generation and Cogeneration

Natural gas-fired units generate electricity using the heat released by the combustion of natural gas:

- CCGTs are an energy and capacity resource. CCGTs use the combination of combustion and steam turbines to generate electricity. Exhaust gases from a combustion turbine flow to a heat recovery steam generator that produces steam to power a steam turbine, resulting in higher efficiencies than those achievable by operating the combustion or steam turbines individually. CCGTs have a relatively high efficiency in converting fuel to electricity in comparison to other thermal generation. Conversion efficiencies are typically about 55% to 60% for CCGTs.
- SCGTs are a capacity resource. SCGTs are stand-alone generating plants that use combustion gases to propel a turbine similar to a jet engine connected to an electrical generator. SCGTs are less efficient than CCGTs in converting fuel to electricity. Conversion efficiencies are typically about 35% to 40% for SCGTs.
- Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power generation and a steam/thermal "host" to use the excess heat produced from the generating process. Steam/thermal hosts may include industries and institutions that need heat such as pulp mills, greenhouses, or hospitals. The efficiency of cogeneration plants is typically about 80% or less, depending on the nature of the steam host.

Large hydroelectric resources such as the Project, with hydroelectric conversion efficiencies of up to 95%, are more efficient at power generation than thermal resources such as natural gas.

Natural gas-fired generation raises unique legal and policy issues in B.C.

Clean Energy Act Considerations

Section 2 of the *Clean Energy Act* sets out two of British Columbia's energy objectives which are relevant to the role of natural gas-fired generation:

- The first, described in Part 1, is found in Subsection 2(c) and provides: "to generate at least 93% of the electricity in British Columbia from clean or renewable resources…". The definition of "clean or renewable resources" in Section 1 of the *Clean Energy Act* does not include natural gas-fired generation.
- The second, described in Part 2, is contained in Subsection 2(g) of the *Clean Energy Act,* setting out the B.C. Government's legislated GHG emission reduction targets

Part 1: *Clean Energy Act* Clean or Renewable Target

BC Hydro currently has five natural gas-fired generating facilities in its system: 1) Burrard [However, as described above, no energy is assumed from Burrard for planning purposes as a result of Subsection 3(5) and 6(2)(b) of the *Clean Energy Act*. Burrard cannot be relied on for dependable capacity after Mica Unit 6 goes into service in about 2016 as a result of the Burrard Thermal Electricity Regulation.], 2) Fort Nelson Generating Station, 3) Prince Rupert Generating Station, 4) Island Generation Plant (IPP), and 5) McMahon Cogeneration Plant (IPP). These facilities contribute 3,520 GWh/year of firm energy to the system, and account for more than 5% of the space currently available for natural gas-fired generation under the 93% clean or renewable target. Thus, little space is left for developing new natural gas-fired generation.

Table 5.33 sets out the maximum GWh of new natural gas-fired generation that could be built in F2022, assuming the 2012 Load Forecast after DSM without LNG load. Table 5.33 also shows the number of MW of new natural gas-fired generation that could be built by F2022 (the Project's earliest in-service date).

Table 5.33 Determination of Permissible Natural Gas-Fired Generation

Year	F2022
Space available for natural gas-fired generation (7% of total generation energy requirements used as a proxy for generation)	4,356 GWh
Energy contribution from existing natural gas-fired generation (GWh)	3,520 GWh
Permissible volume of new natural gas-fired generation that could be built (GWh)	836 GWh
Associated MW of new natural gas-fired generation (CCGT) (90% capacity factor)	106 MW
Associated MW of new natural gas-fired generation (SCGT) (18% capacity factor)	530 MW

Therefore, neither CCGTs nor SCGTs are an alternative to the Project on their own; they must be combined with clean or renewable resources to compare against the Project's 5,100 GWh/year of average energy and 1,100 MW of dependable capacity. Refer to the portfolio analysis in Section 5.5.4. BC Hydro is relying on the remaining GWh of natural gas-fired headroom to facilitate future SCGT capacity needs under contingency circumstances (refer to Section 5.2.3).

Part 2: GHG Offset Requirement

Subsection 2(g) of the *Clean Energy Act* sets out the B.C. Government's legislated GHG emission reduction targets. In addition, Policy Action No. 18 of the 2007 Energy Plan provides that all new natural gas-fired generation must have zero net GHG emissions. This requirement is legislated pursuant to Part 6.1 of the B.C. *Environmental Management Act*. While, to date, regulations to bring Part 6.1 of the *Environmental Management Act* have not been enacted, it is likely that as part of the BCEAA process, which would be triggered by a proposal to construct a CCGT or SCGT with a nameplate capacity of 50 MW or greater, a 100% offset requirement would be imposed through EAC conditions. BC Hydro has factored in GHG offset costs into the UEC values.

Environmental Attributes Overview: Natural gas-fired generation can have land use impacts for the facility itself and extension to the transmission grid. The environmental attributes only include the footprint of the facility itself – the footprint for fuel extraction is not included.

The products of natural gas combustion include the following air contaminants: NO_x, sulphur dioxide (SO_2), carbon monoxide, and PM. These are known as primary emissions. In addition, NO_x is a precursor to ground-level ozone and can lead to its formation in the ambient air. Along with SO_2, NOx is also a precursor of secondary particulate matter. There are known health and environmental effects associated with all of the aforementioned contaminants.

Natural gas-fired generation also emits carbon dioxide, methane, and nitrous oxide, which are GHGs. The GHG emissions of a SCGT facility with a nameplate capacity of 500 MW (18% capacity factor) are about 376,000 tonnes of CO_2e/year. (The SCGT GHG emission factor is about 477 tonnes of CO_2e per GWh).

Metro Vancouver, the regulator in the Lower Mainland, has taken the position that it will not approve any new natural gas-fired generation in the Lower Mainland. Accordingly, for EIS alternative comparison purposes, BC Hydro assumed that a CCGT or SCGT will not be located in the Lower Mainland. The following provides a high level overview of the major permitting requirements for natural gas-fired generation outside the Lower Mainland.

CCGT: Siting a 100 MW CCGT triggers the following material regulatory approvals:

- An EAC under BCEAA from the B.C. Minister of Energy, Mines and Natural Gas, and the B.C. Minister of Environment, as the replacement CCGT will exceed the B.C. Reviewable Projects Regulation threshold of a new powerplant with a nameplate (rated) capacity of 50 MW or greater
- Air emission permit from the B.C. Ministry of Environment under EMA. CCGTs emit NO_x, coarse and fine PM, sulphur dioxide, and ammonia (the latter as part of the select catalytic converter process to reduce NO_x emissions), all of which can impact human health, as well as livestock and agricultural crops. The impact would depend in part on ambient (background) air quality. The public would be involved pursuant to the Public Notification Regulation (B.C. Reg. 202/94).

Assuming permitting could be secured and no legal challenges to the issuance of permits, the 2010 Resource Options Report indicates that lead times for new CCGTs would be about five years.

SCGT: BC Hydro's 2010 Resource Options Report indicates similar lead times for SCGTs as CCGTs. With one exception, SCGTs would trigger similar regulatory approvals for siting CCGTs, including the requirement for an air emission permit from the B.C. Ministry of Environment. As the associated MW of SCGTs is over 200 MW under the *Clean Energy Act* clean or renewable target (see Table 5.33), in the context of this alternative analysis, SCGTs would also trigger CEAA, because the alternative SCGT is a fossil fuel-fired electrical generating station with a production capacity of 200 MW or more (Regulations Designating Physical Activities SOR/2012-147, schedule, Section 2):

- It may be easier to site SCGTs, given that they do not run as often as CCGTs and therefore do not emit as many air contaminants
- However, the newly released performance standard for coal-fired generation of 420 tonnes of CO_2e per GWh contained in the Federal Government's Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations (SOR/2012-167) may challenge new SCGTs. The 420 tonnes of CO_2e per GWh performance standard is the GHG emission intensity level of a CCGT.

Technical and Financial Attribute Overview: Natural gas-fired generation is dispatchable, that is, natural gas-fired generation can adjust power output on demand. The time periods in which dispatchable natural gas-fired generation can be turned on or off may vary, but can be considered in time frames of minutes or hours. This may be contrasted with intermittent clean or renewable resources such as run-of-river and wind, which cannot be controlled by operators. Natural gas-fired generation provides firm energy and dependable capacity.

In contrast to the Project and other clean or renewable resources such as run-of-river, a material portion of the costs of natural gas-fired generation is incurred during operations, due mainly to the cost of fuel. For example, the Project construction and development costs are about 85% of the overall costs, with operating, sustaining capital, and fuel costs (mainly water rentals) comprising the other 15%. For SCGTs, construction and development costs are about 20% of the overall costs, with operating and fuel costs comprising the remaining 80% of the overall costs. Refer to Section 7.1.3 in Volume 1 Section 7 Project Benefits for additional detail.

As a result, natural gas-fired generation has greater variable cost uncertainty when compared to clean or renewable resources. The two material variable cost risks are:

- Fuel price risk: This is the risk that the price of natural gas used to generate electricity will exhibit variability over the course of the 25-year to 30-year expected life of a natural gas-fired generating station. Among the fuels most commonly used to generate electricity, natural gas is the most volatile in price. The most significant recent development to affect natural gas prices has been the emergence of shale gas; long-term natural gas prices have dropped due to advancements in gas extraction technologies and the increase in shale reserves. Because there is future natural gas price uncertainty, BC Hydro does not rely on a single natural gas price forecast. Rather, BC Hydro uses a scenario-based approach employing a range of future natural gas prices developed by Ventyx. The mid Ventyx forecast for natural gas at the Sumas, B.C., hub price is between about $3 per gigajoule (GJ) to $7/GJ ($F2013) over the next 30 years and is used in the portfolio analysis in Section 5.5.4.

- Regulatory risk: GHG costs. The requirement that all new B.C.-based natural gas-fired generation have zero net GHG emissions is discussed above. The financial risks associated with GHG regulatory actions – the market price for GHG offsets – turns on the flexibility of compliance mechanisms. For example, is there flexibility to offset GHG emissions outside the Province of British Columbia? While the B.C. *Greenhouse Gas Reduction (Cap and Trade) Act* (S.B.C. 2008, c.32) contemplates such flexibility through eventual linkage of a B.C.-based cap-and-trade system (the B.C. cap-and-trade system would come into force by issue of a government regulation, which is currently in the consultation stage) to other systems, to date there is no western regional or continent-wide GHG cap-and-trade system. A GHG market confined to B.C. is likely to be more costly than a larger market. BC Hydro adopted a scenario approach to the impact of GHG offset price variability based on Ventyx's GHG price forecast. The GHG price forecasts provide a wide range of possible future GHG offset prices that capture a range of economic and policy scenarios. The low GHG price is the carbon tax at $30/metric tonne of CO_2e, and is used in the portfolio analysis in Section 5.5.4. The high GHG price is about $173/metric tonne of CO_2e ($F2013, levelized between 2022 and 2046) and is

reflected in the upper financial attribute values for CCGTs (UEC, Table 5.34) and SCGTs (UCC, Table 5.35).

Combined Cycle Gas Turbines and Cogeneration

BC Hydro undertook an in-house update of the cost and performance characteristics of gas-fired generation units potentially located in the Kelly Lake/Nicola area in the interior of B.C. BC Hydro also undertook an in-house update for potential cogeneration units in the Lower Mainland. A summary of the technical and financial results for these natural gas-fired generation resource options is contained in Table 5.34.

Table 5.34 Summary of CCGT and Small Cogeneration Gas-Fired Generation Potential

Resource Option	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	Unit Energy Cost at POI ($F2013/MWh)
50 MW CCGT in Kelly/Nicola	1	56	49	300	386	111 – 166
250 MW CCGT in Kelly/Nicola	1	263	236	1,450	1,861	79 – 131
Small cogeneration in Lower Mainland	20	200	200	1,600	1,600	75 – 127

NOTES:

Representative project used to characterize the resource option. Energy is based on a 90% capacity factor and UECs include associated fuel and GHG costs.

Natural gas-fired generation options are based on natural gas price estimates for the 2022–2046 period using the Ventyx spring 2012 medium levelized forecast of $5.37/GJ ($F2013), which is the most likely forecast

Simple Cycle Gas Turbines

BC Hydro undertook an in-house update of the cost and performance characteristics of a representative 100 MW SCGT unit in Kelly/Nicola. The UCC range is shown in Table 5.35.

Table 5.35 Summary of SCGT Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Unit Capacity Costs at POI ($2013/kW-year)
100 MW SCGT in Kelly/Nicola	1	103	98	89 – 121

NOTES:

UCCs for SCGTs are based on an 18% capacity factor and include associated fuel and GHG costs

Natural gas-fired generation options are based on natural gas price estimates for the 2022-2046 period using the Ventyx 2012 spring medium levelized gas price forecast of $5.37/GJ ($F2013)

5.5.2.9 Resource Smart

BC Hydro's Resource Smart program identifies potential efficiency gains at existing BC Hydro hydroelectric facilities. Resource Smart projects result in 1) increased turbine efficiencies, and/or 2) increased nameplate capacity of turbines.

Resource Smart opportunities are limited to BC Hydro's 30 existing hydroelectric facilities. In recent years, BC Hydro has implemented or is implementing a number of

such opportunities. Examples already included in BC Hydro's resource stack as committed resources (discussed above in Section 5.2.1.2) are:

- The addition of an approximately 500 MW fifth unit at Revelstoke Generating Station in the B.C. Interior (Revelstoke Unit 5, in-service in F2011)
- Two additional approximately 500 MW units at Mica Generation Station (increasing capacity by approximately 1,000 MW) in the B.C. Interior (Mica Units 5 and 6, expected to be in-service in F2015 and F2016, respectively)
- G.M. Shrum Units 6 to 8, providing capacity Increase of about 90 MW (in-service in F2012) on the Peace River
- Replacing the runners at Ruskin Generating Station in the Lower Mainland, with about a 9 MW dependable capacity increase and 28 GWh/year of additional energy

The largest remaining Resource Smart project identified in terms of additional dependable capacity is Revelstoke Unit 6. Revelstoke Unit 6 is not an alternative to the Project, as it is a resource that is already included in the LRBs for purposes of this EIS; refer to Section 5.2.2.2 above.

Environmental Attribute Overview: Resource Smart projects generally occur within the existing hydroelectric facility footprint. Resource Smart projects may change hydroelectric facility operations (i.e., reservoir fluctuations and/or downstream flows).

Technical and Financial Attribute Overview: Table 5.36 is a list of potential additional Resource Smart projects.

Table 5.36 Summary of Resource Smart Potential

Resource Smart Option	Energy (GWh)	UEC at POI ($/MWh, $F2013)	Capacity (MW)	UCC at POI ($/kW-year, $F2013)
G.M. Shrum Units 1–5 capacity increase (Peace River)	0	N/A	220 (about 44 MW per unit)	28
Cheakamus generator upgrade (Whistler area, Lower Mainland)	45	36	22	74
Strathcona additional unit (Campbell River, Vancouver Island)	0	N/A	31	118
Ladore additional unit (Campbell River, Vancouver Island)	8	336	9	299
Ash River additional unit (Ash River, Vancouver Island)	30	100	9	334
Puntledge additional unit (Puntledge River, Vancouver Island)	18	82	10	149
Duncan Dam new generation (Duncan River/Columbia River area)	103	115	30	396
Lajoie additional unit (Bridge River/Fraser River area)	80	125	30	333
Replace runners at Seven Mile Generating Station (Pend-d'Oreille River, Interior)	26	411	32	334

Resource Smart projects contained in the above table would typically be implemented at the time of other necessary safety and reliability-related upgrades at the named

BC Hydro hydroelectric facilities. Resource Smart projects typically require BCUC approval prior to implementation; two recent examples are the Ruskin Dam and Powerhouse Upgrade Project and the John Hart Generating Station Replacement Project (BCUC decision pending).

BC Hydro is not currently anticipating undertaking the G.M. Shrum Units 1–5 Capacity Increase project because over the next 10 years, BC Hydro will be upgrading most of the 10 G.M. Shrum Generating Station units through other projects, making the undertaking of the GM Shrum Units 1–5 Capacity Increase project difficult during that time frame. BC Hydro notes that the G.M. Shrum Units 1–5 Capacity Increase project is not an alternative on its own to the Project, as it only defers the need for capacity by two years.

5.5.2.10 Pumped Storage

Pumped storage hydro units are capacity resource options and use electricity from the grid, typically during light load hours, to pump water from a lower elevation reservoir to an upper elevation reservoir. The water is then released during heavy load hours to generate electricity. Reversible turbine/generator assemblies or separate pumps and turbines are used in pumped storage facilities. Pumped storage units are a net consumer of electricity due to inherent inefficiencies in the pumping-generating cycle, which result in recovery of about only 70% of the energy used.

Environmental Attribute Overview: The construction of greenfield pumped storage facilities usually creates reservoirs, thus leading to land loss and impacting vegetation and wildlife. It may be possible to use natural bodies of water for reservoirs or using pre-existing dams, thus minimizing this impact. BC Hydro looked at both potential greenfield pumped storage facilities in the Lower Mainland and on Vancouver Island, and at the possibility of pumped storage at BC Hydro's existing Mica Generating Station in the Interior. Operationally, pumped storage can lead to rapid and frequent changes in water reservoir levels, which can impact fish and fish habitat through reduction in the wetted littoral zone (close to shore to about a maximum of 10 m or so in depth, where a large part of biological production occurs), changes to water velocity/directions and temperature, and increased erosion. Pumped storage facilities can create changes in land use through an extension to the transmission line grid.

There are no commercial pumped storage facilities in B.C., and only one pumped storage facility operating in Canada, which was permitted in the 1950s. Siting a pumped storage facility in B.C. triggers a number of regulatory/government agency approvals, including:

- A Course of Action Decision under CEAA, because in the context of this EIS, pumped storage is a hydroelectric generating station with a production capacity of 200 MW or more (Regulations Designating Physical Activities SOR/2012-147, schedule, Section 2)
- An EAC under BCEAA, because pumped storage facilities will exceed the B.C. Reviewable Projects Regulation threshold of a new powerplant with a nameplate (rated) capacity of 50 MW or greater

Technical and Financial Attribute Overview: The ability to store water and release it during times of system need makes pumped storage a useful capacity resource. Pumped storage hydro units can respond quickly to variations in system demand and

can provide ancillary services such as voltage regulation. As described above, pumped storage consumes energy due to the inefficiencies in the pumping-generation cycle.

BC Hydro engaged Knight Piésold Ltd. to identify greenfield pumped storage potential in the Lower Mainland and Vancouver Island regions, and engaged Hatch Ltd. to assess the cost of installing a pump-turbine or a pump at Mica Generating Station. A summary of the technical and financial results for the pumped storage resource option is contained in Table 5.37. As pumped storage is considered a capacity option, only the unit capacity cost is shown.

Table 5.37 Summary of Pumped Storage Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Unit Capacity Costs at POI ($F2013/kW-year)
Kelly/Nicola	4	4,000	4,000	235 – 279
Mica	1	500	465	216
Vancouver Island	84	79,000	79,000	242 – 440
Lower Mainland	105	105,000	105,000	232 – 407
Total	**194**	**188,500**	**188,465**	**216 – 440**

NOTE:
UCCs for pumped storage include fuel costs using an 18% capacity factor and 30% energy loss factor

5.5.2.11 Summary of Available Resources

The UEC results are summarized in Table 5.38. The UEC for the Project are included for comparison purposes.

Table 5.38 UECs of Available Energy Resource Supply Options

Energy Resource	Total FELCC Energy (GWh/year)	Total DGC or ELCC Capacity (MW)	Unit Energy Costs at POI ($F2013/MWh)
Biomass – wood based	11,946	1,499	125 – 985
Biomass – biogas	134	16	60 – 159
Biomass – municipal solid waste	499	58	117 – 259
Wind – onshore	46,165 ~~38,885~~	3,942	96 – 332
Wind – offshore	50,261	3,681	190 - 734
Geothermal	5,992	780	88 – 581
Run-of-river	33,619 ~~35,880~~	1,018 ~~1,074~~	82 – 600
Site C Clean Energy Project	4,700	1,100	94
CCGT and cogeneration	7,623	964	75 – 166

The UCCs of the supply-side capacity resource options are summarized in Table 5.39.

Table 5.39 UCCs of Available Capacity Resource Supply Options

Resource Type	Capacity Options	Dependable Capacity (MW)	Unit Capacity Costs at POI ($F2013/kW-year)
SCGT	Various Locations	98	89 – 121
Pumped Storage	Various Locations	1,000	216 – 440
Resource Smart	Various Locations	About 390	28 – 370

5.5.3 Portfolio Modelling Framework

In addition to assessing available resources as reflected in Section 5.5.2, BC Hydro analyzed the available resources through portfolio analysis to determine whether the Project is the preferred option to serve the need identified in Section 5.2:

- Section 5.5.3 provides details regarding the portfolio-related models, modelling constraints, and input parameters
- Section 5.5.4 discusses the portfolio results. The portfolio results indicate that the Project is a cost-effective resource option compared to the available resources.

5.5.3.1 Introduction to Portfolio Analysis

Portfolio analysis is a process of developing and evaluating resource portfolios, each consisting of a sequence of supply-side and demand-side resources to meet the energy and capacity needs of BC Hydro's customers. In its 2006 IEP/LTAP Decision, the BCUC stated "that a portfolio analysis is consistent with the Commission's Guidelines", and "is a best practice for IEP or IRP analysis" (BCUC 2006).

In general, portfolios were created in this analysis for the planning period from F2015 to F2041. Each portfolio contains BC Hydro's current DSM target. The portfolio analysis for the Project examined how the Project compares to combinations of available resources. This analysis was conducted by comparing portfolios including the Project against portfolios of resources that excluded the Project but combining available resources that provide approximately the same amount of energy and capacity. In general, these alternatives are composed of multiple available resource projects, as most alternatives to the Project are not capable of delivering comparable amounts of energy and dependable capacity on their own. BC Hydro compares portfolios based on portfolio technical, financial, environmental, and economic development attributes.

Figure 5.8 shows a schematic of the overall process for developing portfolios and analyzing the results. The following sections provide a more detailed discussion of the components of the process.

5.5.3.2 Portfolio Analysis Process and Models

BC Hydro's portfolio analysis uses a suite of models:

- Hydrological system simulation model (HYSIM)
- System Optimizer
- Multi-Attributes Portfolio Analysis

HYSIM is a BC Hydro-developed model. It is a system production cost model, which runs through 60 years of water records in modelling the large hydro system. HYSIM provides insight on how water variability may impact portfolio performance. It develops the monthly generation profile for the large hydro system that is an input to System Optimizer. For additional details on HYSIM, please see Section 11.4 in Volume 2 Section 11 Environmental Background.

Resource portfolios were developed using System Optimizer, a product of Ventyx that has been adopted by several utilities in North America. System Optimizer is a deterministic linear optimization model that selects an optimal resource expansion sequence (referred to as a portfolio) of generation and transmission additions for a given set of input assumptions. System Optimizer minimizes the present value of net costs, including the incremental fixed capital and operating costs for new resources and total system production costs (inclusive of trade revenues), to meet a given load based on BC Hydro's planning criteria. System Optimizer does not capture either resource delivery risk, or the value of ancillary benefits (such as the ability to integrate intermittent resources and firming capability), which could be significant for resources such as the Project. The benefits of the Project are described in Volume 1 Section 7 Project Benefits.

Multi-Attributes Portfolio Analysis is a BC Hydro-developed model. It takes the portfolio output from System Optimizer and tracks the various attributes (e.g., environmental and economic development attributes as described in Section 5.5.1) for the portfolios.

5.5.3.3 Modelling Constraints

The portfolios created satisfy good utility practice (e.g., they meet reliability criteria). Two *Clean Energy Act* objectives are treated as constraints: 1) achieve self-sufficiency, and 2) meet the 93% clean or renewable energy target described in respect of natural gas-fired generation in Section 5.5.2.8. In addition, the 2007 Energy Plan requirement that natural gas-fired generation GHG emissions be completely offset is treated as a modelling constraint.

As discussed in Section 5.2.2.2, the *Clean Energy Act* objective of BC Hydro to reduce the increase in demand for electricity by the year 2020 by at least 66% is reflected in the DSM Target. As a result, all portfolios considered have at least 66% of forecast demand met by DSM based on the December 2012 mid Load Forecast.

5.5.3.4 Financial Parameters

Costs are expressed on a present value basis to capture the impact of the timing of costs and trade revenues over the planning horizon. The portfolio analysis results are expressed in $F2013 dollars. The present values of the portfolios reflect the costs (or levelized costs, where appropriate) for the planning period F2015 to F2041. It is expected that extending the planning period beyond F2041 would increase the additional value of a portfolio with Project relative to one without the Project, reflecting the Project's long expected life.

The key financial parameters in the portfolio analysis are described below.

Inflation Rate

Where nominal and real dollar conversion was necessary, a rate of 2% was assumed as the average inflation rate outlook. This inflationary assumption is consistent with the B.C. Consumer Price Index, which is provided in the Province of B.C. 2012 Budget and Fiscal Plan. Aside from the annual inflationary assumption, the portfolio analysis assumes no other incremental cost escalation or inflationary allowance for capital costs.

Discount Rate

BC Hydro used a 6% real discount rate in the portfolio cost assessments.

Cost of Capital

Policy Action #13 of the Provincial Government's 2002 Energy Plan (page 30) provides that the private sector (i.e., IPPs) will develop new electricity generation, with BC Hydro restricted to improvements at existing plants (such as Resource Smart projects) and the Project. The BCUC in its 2006 IEP/LTAP Decision, page 205, found:

> "…the [BCUC] panel agrees with BC Hydro [and the customer intervenors] that project evaluation methodology must consider the actual costs, benefits, risks and other characteristics of individual projects that may be relevant to cost-effectiveness, and should not seek to artificially compensate for real differences in projects costs, *including possible differences in the cost of capital between BC Hydro and other developers. With respect to the cost of capital, BC Hydro projects will clearly have an advantage as a result of…access to the Province's high credit rating*." [Emphasis added].

BC Hydro is an agent of Her Majesty the Queen in the right of the Province of British Columbia. BC Hydro's borrowing is guaranteed by the Province; BC Hydro can also borrow directly from the Province. BC Hydro's weighted average cost of capital (the overall costs of combined debt and equity capital used to finance an acquisition) is 5.5% (real), which is rounded upwards to 6% (real) for purposes of this EIS and the portfolio alternatives evaluation.

It is widely acknowledged that the private sector, including IPPs, has higher borrowing costs than governments such as the B.C. Government. Consistent with the BCUC's 2006 IEP/LTAP Decision, BC Hydro used a higher weighted average cost of capital for the available resource portfolios, as these would be developed by IPPs. Based on its experience with negotiating with IPPs and other third-party developers, BC Hydro used a weighted average cost of capital of 8% (real) for IPPs for purposes of this EIS. In a study for the Western Electric Coordinating Council, Energy + Environmental Economics used an after tax weighted average capital cost for IPPs of 8.25% (Energy + Environmental Economics 2012).

U.S./Canadian Exchange Rate

Assumptions about the U.S. to Canadian dollar are required for the conversion of market price forecasts. The conversion rate assumption is $0.97 U.S/Cdn.

GHG Offset Cost

BC Hydro has explicitly considered the cost to offset GHG emissions from natural gas-fired generation because this will become financial liabilities for BC Hydro customers as a result of the requirement to completely offset such GHG emissions. BC Hydro conservatively used the lowest GHG offset cost of $30/t of CO_2e, based on the B.C. carbon tax for the portfolio analysis. Refer to Section 5.5.2.8 for a discussion of higher GHG offset price scenarios.

Soft Cost Adder

As described above in Section 5.5.1.1, the Project cost estimate includes costs for mitigation measures, regulatory review, First Nation consultation, and public engagement. The UECs and UCCs for available resources set out in Section 5.5.2 do not include such costs.

Implementation of the available resources would entail mitigation, regulatory review, First Nation consultation, and public engagement costs (called soft costs). For example:

- Replacing the Project's dependable capacity contribution of 1,100 MW requires either 1) a large replacement pumped storage facility, which would trigger both CEAA and BCEAA, and would have environmental effects described in Section 5.5.2.10, or 2) a combination of SCGTs and pumped storage. A replacement SCGT would trigger BCEAA, CEAA, and air emission permitting requirements (refer to Section 5.5.2.8).
- Replacing the Project's average energy contribution of 5,100 GWh/year would entail acquiring clean or renewable intermittent resources such as wind resources. All wind projects awarded EPAs triggered BCEAA because they have a nameplate capacity of 50 MW or greater; refer to Table 5.40 below. The table of mitigation-related commitments appended to EAC E06-03 issued in respect of Dokie Wind Project is several pages in length.

Table 5.40 BC Hydro EPA Wind Projects and BCEAA Trigger

Project	Nameplate Capacity (MW)
Bear Mountain	102
Dokie Wind	144
Quality Wind	142
Cape Scott	99
Tumbler Ridge	45
Wildmare	77
Meikle	117
Bull Moose	60

BC Hydro has put a cost adder of 5% on available resource portfolios to reflect the fact that implementing the available resource options would entail soft cost expenditures. BC Hydro chose 5% on the basis of its experience; for example, the environmental assessment, First Nation, and stakeholder engagement costs of a sample of recent representative BC Hydro capital projects ranged from 0.02% to about 10%.

Sunk Costs

A key concept in understanding the portfolio analysis is the concept of incremental costs. The incremental cost approach focuses on examining how costs change based on potential alternatives. Sunk costs, which are costs that have been incurred prior to the current analysis, are not relevant for purposes of the incremental cost analysis. Accordingly, the Project-related sunk costs (about $5/MWh) have been removed for purposes of the portfolio analysis.

5.5.3.5 Load, Market and Transmission Parameters

Load/Resource Balance Assumptions

Portfolios were created and evaluated across the base LRB gap (Mid-level 2012 Load Forecast, existing and committed resources, the current BC Hydro DSM target, Revelstoke Unit 6; refer to Section 5.2.2.2).

Market Energy Price Assumptions

Using costs to compare portfolios requires estimating the costs and trade revenues of each portfolio operating over the planning time frame. These operating costs and revenues are affected by market price assumptions, including the market prices of natural gas, GHG, and electricity. BC Hydro used the Ventyx Spring 2012 market price forecast in the portfolio analysis. This Ventyx forecast assumes slower economic growth and is the basis for BC Hydro's most likely market price forecast. The forecast of Mid-Columbia spot market electricity price is the hourly price for buying and selling surplus electricity at a trading hub near the Washington/Oregon border. In the portfolio analysis in Section 5.5.4 BC Hydro uses a forecast of Mid-Columbia spot market electricity prices ranging from about $25/MWh to $50/MWh (with a further adjustment for the costs of wheeling and losses to the B.C. border) over the next 30 years.

Transmission Assumptions

The analysis of the long-term transmission requirements is based on BC Hydro's Integrated System Planning Criteria. These criteria define BC Hydro's guidelines for planning a reliable transmission network that is adequate for dispatching designated generation resources to serve the forecasted demand. For system performance under normal and emergency conditions, BC Hydro's planning criteria conform to the BCUC-approved North American Electric Reliability Corporation (NERC) Reliability Standards for transmission planning.

In accordance with the criteria, the System Optimizer identifies where and when incremental transmission capacity will be required for a particular portfolio. System Optimizer first selects a set of applicable wire or non-wire transmission options for removing congestion from an existing transmission path by adding incremental transfer capacity to the constrained path. The result is reviewed and, if needed, the reinforcement requirements are adjusted. The present values of the portfolios reflect these adjustments.

5.5.3.6 Characterization of Portfolio Attributes

Once the System Optimizer creates portfolios for each scenario, the Multi-Attributes Portfolio Analysis process is used to determine the financial, technical, environmental, and economic development characteristics of each portfolio. Please see Section 5.5.1 for a more detailed description of the attributes.

The portfolio attributes are summarized at a level appropriate for comparing the Project against other portfolios using consequence tables. A consequence table is a collection of the above information arranged in a matrix format so that the Available Resource options considered are displayed as column headers, the relevant decision objectives are displayed as row labels, and for each row, the specific units of measurement are provided. While some judgment is required to reduce the full analysis down to a

condensed level, this view allows a reader to easily see the relative impacts of Available Resource options across alternatives and decision objectives.

5.5.3.7 Uncertainties and Risks Not Captured by Portfolio Modelling

Key uncertainties and risks include the following:

- Current DSM Target – The portfolio modelling assumes that the current DSM target will deliver the expected energy and dependable capacity savings
- Expected Life – The Project is expected to have a life of more than 100 years. In contrast, EPAs with IPPs for available resources have varying durations that are shorter, ranging from 15 to 40 years (refer to Section 5.5.2 for each available resource that has been the subject of prior BC Hydro power acquisition processes such as run-of-river, wind and bioenergy). As described in Section 5.2.3, at the end of EPA terms, there is significant supply and price risk to BC Hydro because there is no assurance that 1) IPP available resource-related projects will continue operations past the expiry of EPAs, 2) that IPPs will contract with BC Hydro if they do continue to operate, or 3) that IPPs will contract at a price comparable to their current real-dollar prices.
- IPP Attrition Risk – The portfolio modelling does not reflect the relatively high IPP attrition rate that BC Hydro has observed through its power acquisition processes. If BC Hydro were to pursue some combination of available resources instead of the Project, it would likely have to award EPAs representing more energy than the lost Project contribution of 5,100 GWh/year of average energy.
- Regulatory Risk – The portfolio model does not account for available resource development and regulatory risk. If BC Hydro were to pursue available resources, the EPAs with IPPs must be filed with the BCUC for acceptance pursuant to Section 71 of the *Utilities Commission Act.* BC Hydro qualitatively described available resource development and regulatory risks above in Section 5.5.2; see, for example, SCGTs (air emission permitting) and pumped storage (only one such facility permitted to date in Canada).

5.5.4 Portfolio Evaluation Results

This section compares the technical, financial, environmental, and economic development attributes of portfolios with and without the Project.

Volume 1 Appendix D Part 4 Portfolio Attributes provides additional detail on the full suite of attributes described in Section 5.5.1. High-level environmental footprints and economic development attributes are used for comparison of resource options across provincial-scale portfolios, and act as proxies for more detailed environmental, social, and heritage effects of potential projects. Since detailed site-specific information is unknown for the majority of the potential sites in the database, detailed environmental, social, and heritage attributes are not possible, or intended to be used, for individual site-specific resource option evaluations and comparisons.

5.5.4.1 Portfolio Development

To compare the Project to available resources, BC Hydro built a number of portfolios including the Project and excluding the Project. Three categories of portfolios were established, using different assumptions regarding available resources:

- **Site C Portfolios** that include the Project, with the remaining energy and capacity gap being filled using clean or renewable generation resources

- **Clean Generation Portfolios** that exclude the Project and fill the energy and capacity gap using clean or renewable generation resources. As referenced in Section 5.5.2, available clean or renewable resources for portfolio purposes are wind, run-of-river, and biomass to provide energy and capacity, with pumped storage providing backup capacity but representing an energy consumer.

- **Clean + Thermal Generation Portfolios** that exclude the Project and fill the energy gap using clean or renewable generation resources as in the Clean Generation Portfolio, while backup capacity is provided by thermal generation (in the form of SCGTs) up to the 93% clean or renewable target, as well as pumped storage. It should be noted that the partial replacement of the dependable capacity provided by the Project with SCGTs would use up all of the 7% non-clean headroom. As a result, BC Hydro's ability to use natural gas-fired generation for contingency resource planning purposes is foregone. This value is not fully represented in the portfolio analysis undertaken.

A number of assumptions are consistent through all portfolios, including:

- LRB is based on 2012 Load Forecast with no LNG load
- Electricity and gas market scenario based on Ventyx's spring 2012 price forecast
- The current BC Hydro DSM target is used in every portfolio
- The cost of most alternatives is based on 2010 Resource Options Report data using an 8% weighted average cost of capital (refer to Section 5.5.3.4)
- Wind costs are based on the 2012 wind cost update (see Section 5.4.1.2)

Refer to Figure 5.9 for a representation of the portfolios considered.

Once the portfolios were constructed, BC Hydro compared the technical, financial, environmental, and economic development attributes between these portfolios.

5.5.4.2 Technical Attributes

The portfolios used to compare alternatives to the Project are constructed to have similar overall technical attributes (i.e., each portfolio is built to fill the energy and capacity gaps identified in Section 5.2.2). However, there are some differences between these portfolios that are important to highlight.

Energy: BC Hydro's portfolio building exercise identified wind as the primary energy technology to provide energy in both the Clean Generation portfolios and the Clean + Thermal Generation portfolios. The balance of energy requirements are mostly provided by biomass resources in the Clean Generation portfolio, while both biomass and SCGTs provide energy in the Clean + Thermal Generation portfolio. Run-of-river resources provide only a minor amount of energy. This result is not aligned with the results of previous BC Hydro power acquisition processes – in these calls, run-of-river was the primary resource bid in. This is generally due to the lower wind costs resulting from the wind cost update discussed in Section 5.4.1.2. If wind costs are left at the levels in the Resource Options Report, run-of-river hydro and/or biomass would provide higher proportions of energy for the portfolio.

The Clean Generation portfolio requires more energy resources in total due to the requirement to offset energy losses from pumped storage. That is, an additional 700 GWh/year of energy generation resources are required in the Clean Generation portfolio, due to the net energy consumption from the pumped storage capacity resource.

Figure 5.10 shows the comparison of the energy provided by the Project to a 5,100 GWh/year block of energy resources that are similar to those selected in the Clean Generation and Clean + Thermal Generation portfolios.

Capacity: In both the Clean Generation and Clean + Thermal Generation portfolios, capacity is partially provided by the DGC of biomass and the ELCC of wind resources. The balance of the capacity requirements are provided by DGC from pumped storage in the Clean Generation portfolio, while SCGTs and pumped storage provide DGC in the Clean + Thermal Generation Portfolio.

ELCC has a greater level of uncertainty than the DGC of a dependable capacity resource such as the Project, which is set as part of the project design. A portfolio that relies significantly on the contribution of intermittent clean or renewable generation to ELCC has the potential to overstate the available capacity due to an expected capacity contribution versus having dependable capacity that is known to be available when the system requires it.

Both the Clean Generation and Clean + Thermal Generation portfolios rely significantly on intermittent resources for the energy contribution. There may be additional firming and/or shaping capability required from the BC Hydro system that is not included in the portfolio analysis.

Figure 5.11 shows the comparison of the dependable capacity provided by the Project to an 1,100 MW block of energy resources that are similar to those selected in the Clean Generation and Clean + Thermal Generation portfolios.

5.5.4.3 Financial Attributes

The analysis evaluated the cost-effectiveness of the Project by comparing the present value of the costs between portfolios with and without the Project. This represents the financial benefits over the 30-year analysis period. This present value calculation was performed for a range of in-service dates for the Project to evaluate whether the Project was cost-effective both at F2022 and at F2024. Table 5.41 shows the results of this present value analysis. Note that the present value analysis is based on a no LNG load scenario and on the current DSM target. The present value analysis does not take DSM or other resource delivery risk into account.

Table 5.41 Portfolio Present Value Comparison

Portfolio Comparison	Project In-Service Date	Portfolio Present Value Differential ($ million)
Site C portfolio compared to Clean Generation portfolio	F2022	460 ~~450~~
	F2024	660
Site C portfolio compared to Clean + Thermal Generation portfolio	F2022	(150)
	F2024	180

NOTES:
Positive values indicate that the Site C portfolio has lower costs than the alternative portfolio
Present value calculated at 6% discount rate
All values in F2013 dollars, rounded to nearest $10 million

This present value analysis shows that the Project is cost-effective at its earliest in-service date, saving about $450 million in present value, compared to a Clean

Generation portfolio. The Project is more expensive than a Clean + Thermal Generation portfolio at a F2022 in-service date; however, the Project becomes more cost-effective than a Clean + Thermal Generation portfolio with a F2024 in-service date. A change to BC Hydro's load-resource balances that accelerated the capacity and/or energy gap would create a similar change to the Project present value benefits.

In addition to the present value analysis, BC Hydro evaluated the adjusted UEC of the Project against the adjusted UEC of a comparable block of 5,100 GWh/year of energy and 1,100 MW of capacity. This adjusted UEC represents the present value of the amount BC Hydro's customers pay per unit energy delivered, and is a proxy for the financial benefits over project life. Table 5.42 provides the difference in portfolio UEC between portfolios with and without the Project in F$2013.

Table 5.42 Adjusted Unit Energy Cost Comparison

	Clean Generation	Clean + Thermal Generation	Project
Adjusted UEC ($/MWh, $F2013)	181	155~~6~~	110

NOTE:
UEC values include transmission-related costs to the Lower Mainland, wind integration costs, soft costs, and costs of capacity backup, and exclude sunk costs

5.5.4.4 Environmental Attributes

Portfolios with and without the Project were compared based on their environmental attributes. More details of the measures can be found in Section 5.5.1. Table 5.43 shows the differences in the environmental attributes between the Project and a 5,100 GWh/1,100 MW block of power from the Clean Generation and Clean + Thermal Generation portfolios.

Note that the environmental attributes for the Project are unique within the range of resource options under analysis, given the advanced level of project definition for the Project and accompanying accuracy in the project footprint. The portfolios without the Project are populated with forecast generic 'typical' projects with estimated footprints. The portfolio values include the impacts of associated transmission requirements to the POI.

Table 5.43 Environmental Attribute Comparison

Environmental Attribute	Clean Generation	Clean + Thermal Generation	Project
Land footprint (ha)	2,230	2,430	5,660
Affected stream length (km)	15	15	125
Reservoir created (ha)	0	0	9,300
Operational GHG Emissions (t/year, 000s)	200	650	0
Local Air Emissions (t/year, 000s)			
NOx	0.5	0.6	0
Carbon Monoxide	0.4	1.3	0

NOTE:
All values are rounded

Land and freshwater footprint: The environmental attributes for the Project are unique compared to the alternatives shown as a result of the advanced level of project definition for the Project, which allows a higher level of accuracy in determining the Project footprint. The portfolios without the Project are populated with forecast "typical" projects with estimated footprints. As a result, the differences in environmental attributes between portfolios shown in this section compare a defined attribute for the Project to a representative estimate for IPPs. The actual difference in attributes between portfolios cannot be known with certainty.

Both the Clean and the Clean + Thermal Generation portfolios identified wind resources as the primary alternative source of energy. Based on these portfolio compositions, the comparison of environmental attributes shows that the Project could have a larger land footprint than portfolios without the project. However, the difference between the portfolios is less than the full 5,660 ha Project land footprint, as a portfolio without the Project must employ different supply-side resources to meet energy and capacity needs, which also have environmental footprints.

As with the land footprint, based on the wind-heavy portfolio composition of the Clean and the Clean + Thermal Generation portfolios, the Project could have a larger freshwater footprint than the portfolios that do not include the Project.

The land and freshwater footprint of the Project 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 of alternative resources. As a result, portfolios with the Project include the creation of a 9,330 ha reservoir, while portfolios without the Project do not. It should be noted, however, that pumped storage, an alternative capacity-rich option and net energy consumer, is assumed to occur on existing water bodies with no reservoir footprints for this modelling analysis. Since, to date, no pumped storage project has ever been permitted in B.C., this is a conservative assumption.

The differences in land and freshwater footprint are highly dependent on the mix of energy resources. The portfolios of available resources 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 Project. This is because wind and biomass resources generally have smaller footprints per unit energy delivered than either the Project or run-of-river hydro.

It is also important to note that the land footprints in Table 5.43 only include the footprint of the primary generation site. For hydroelectric projects such as the Project and run-of-river resources, this footprint therefore includes the structures to capture the fuel (i.e., the water) for generation purposes. For other available resource options such as natural gas-fired generation and biomass, the fuel collection footprint is not included in the land footprint.

GHG Emissions: The portfolio analysis compared the operating phase GHG emissions due to fuel combustion between the portfolios. The operating phase GHGs are sufficient for planning-level analysis. A full assessment of the life-cycle GHGs of the Project may be found in Volume 2 Section 15 Greenhouse Gases.

The portfolio including the Project has lower operational GHG emissions than both portfolios not including the Project. The Clean Generation portfolio selects a municipal

solid waste 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.

Local Air Emissions: The portfolio including the Project has lower local air emissions than both portfolios not including the Project. The Clean Generation portfolio selects both wood-based biomass and municipal solid waste 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, as a result, has the highest level of local air emissions.

Marine Attributes: Due to the location and characteristics of the Project, there are no significant differences in the marine attributes between portfolios with and without the Project.

Location of Portfolio Footprint: The locations of the environmental attributes used in the analysis of alternatives were compared between portfolios. The Project is located solely in the Northeast Development Region (NEDR), while the available resources are located in a range of locations across the province. However, the portfolio analysis identified wind as the primary source of energy to the system, and more than 90% of wind resources identified were located in the NEDR. As a result, more than 50% of the land footprint in both the Clean and the Clean + Thermal Generation portfolios would be located in the NEDR, with the balance in the Lower Mainland and on Vancouver Island.

5.5.4.5 Economic Development Attributes

Portfolios with and without the Project were compared based on their economic development attributes, including jobs and GDP. Table 5.44 shows the differences in the economic development attributes between the Project and a 5,100 GWh/1,100 MW block of power from the Clean Generation and the Clean + Thermal Generation portfolios. The portfolio values include the impacts of associated transmission requirements to the POI.

Table 5.44 Economic Development Attribute Comparison

Economic Development Attribute	Clean Generation	Clean + Thermal Generation	Project
Construction jobs (total jobs)	33,200	28,500	44,200
Construction GDP ($ million)	2,600	2,200	3,500
Operations jobs (jobs per year)	1,175	1,025	75

NOTE:
All values rounded

The portfolio with the Project generally increased measures of economic development during construction as compared to portfolios without the Project. Jobs and GDP related to construction are higher for the portfolio including the Project, due to the high job intensity of the construction period. Jobs and GDP during operations are lower for the portfolio including the Project, as a result of the low operating costs for the Project.

These estimates are high level for use in comparing the resource options at a portfolio level, and as with the environmental attributes, the exact difference between the economic development attributes is uncertain.

5.5.5 Summary and Rationale for Project Selection

There is a need for new energy and capacity resources within the next 10 to 15 years of BC Hydro's planning horizon in order to meet forecast customer demand, as demonstrated in Section 5.2.2. New energy and capacity resources may be required at the Project's earliest in-service date in scenarios where BC Hydro is required to meet LNG facility non-compression load, if BC Hydro's current DSM target does not deliver anticipated energy and/or capacity volumes, or if higher than mid-load forecasts are experienced. BC Hydro has an obligation to meet this customer demand, and has evaluated a range of different options to do so.

The Project is the most cost-effective manner in which BC Hydro can meet this need, as shown by the portfolio analysis in Section 5.5.4. The Project would also provide the additional benefits of economic development and employment, and would generate electricity with comparatively low GHG emissions per unit energy.

- Portfolios including the Project generally have a lower present value of costs to ratepayers, as compared to portfolios including only clean or renewable resources, and portfolios including both clean and thermal resources
- The environmental footprint analysis shows that the Project may have a larger land and freshwater footprint than portfolios of alternative resource options; however, this is dependent on the mix of resources that would replace the Project
- The Project would have a lower amount of greenhouse gas emissions and local air emissions than portfolios of alternative resource options, which would involve the combustion of fuel at municipal solid waste and/or natural gas facilities
- The economic development attributes of the portfolio analysis show that portfolios including the Project provide higher amounts of provincial GDP and employment during construction

Based on this portfolio analysis, BC Hydro believes that the Project provides the best combination of financial, technical, environmental, and economic development attributes and is therefore a preferred option to meet the need for energy and capacity within BC Hydro's planning horizon.

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