Integrated Resource Plan

Chapter 3

Resource Options

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3.1 Introduction

This chapter provides a summary of BC Hydro's assessment of the resource options potential in B.C. and the characteristics or attributes of the resource options. BC Hydro's existing system, including the generation and storage Heritage assets listed in Schedule 1 to the *Clean Energy Act* (***CEA***), has finite storage and shaping capability. To augment the existing system and minimize the overall cost of electricity supply to its customers within the parameters set out in the *CEA*, BC Hydro needs to select new energy and capacity resources.

New energy resources impact the existing system's performance in different ways. This chapter describes all potential energy resources and assesses them with respect to impact on the system, cost to integrate (e.g., wind), and whether the energy can be delivered to the system during a period when it is needed. The resource options information – namely the technical, financial, environmental and economic development attributes – is used in the portfolio analysis shown in Chapter 6, where the costs and impacts of the new resource additions required to meet the energy and capacity needs of BC Hydro's customers are assessed on a system-wide basis over the planning period.

3.1.1 2013 Resource Options Report Update

The 2010 Resource Options Report (**ROR**) reflected BC Hydro's understanding of the resource potential in December 2010. BC Hydro developed the 2010 ROR attributes and costs based on information from BC Hydro's project experience, consultant studies, and First Nations and stakeholder input, including input from people with relevant technical expertise and information such as Independent Power Producers (**IPPs**). A consultation report summarizing this input is contained in Appendix 3A-2 of the Integrated Resource Plan (**IRP**). In addition, technical studies were conducted by BC Hydro and its consultants on a number of options, including coal-fired generation with carbon capture and sequestration (**CCS**), run-of-river hydroelectric, wood-based biomass and pumped storage. These studies are referenced under each individual resource option.

For the 2013 ROR Update, information obtained in the 2010 ROR was reviewed for material changes to availabilities and costs. BC Hydro resources and those resource options bid into previous acquisition processes by IPPs have been reviewed and updated. These updates include three of the five Demand Side Management (**DSM**) options, some Resource Smart projects such as the GM Shrum (**GMS**) generating station Units 1-5 Capacity Increase, and updates to available resource options including wood-based biomass, municipal solid waste (**MSW**), onshore/offshore wind, run-of-river and natural gas-fired generation. There have also been updates to other resources such as geothermal, pumped storage and solar.

The Unit Energy Costs (**UECs**) and Unit Capacity Costs (**UCCs**) have been updated for all resource options using BC Hydro's updated Weighted Average Cost of Capital (**WACC**) to reflect long-term forecasts of project borrowing costs and the lower financing costs available in the markets. For BC Hydro-owned projects, a 5 per cent real cost of capital was utilized. For third party developed projects, a 7 per cent real cost of capital was used. The private sector, including IPPs, has higher borrowing costs than governments, such as the B.C. Government. The WACCs for BC Hydro and third party resource developers are discussed in greater detail in section 3.2.2. Chapter 6 includes a sensitivity analysis reflecting a third party WACC of 6 per cent real.

The resource options information in the 2013 ROR Update is generally at a level of detail and accuracy that is appropriate for long-term resource planning and portfolio analysis. For most resource options, this level of information is not considered sufficiently accurate to establish the characteristics of site-specific resource options for development or acquisition purposes. Conducting resource options assessments is an ongoing part of BC Hydro's resource planning work and the information is updated on a regular basis to reflect new findings or to support a particular planning process.

The complete 2013 ROR Update is attached as Appendix 3A. The 2013 ROR Update looks out 20 to 30 years[1] and assesses the DSM, supply-side generation and transmission resource options that are consistent with the policy and legislated objectives of the B.C. Government, including those specified in the *CEA*.

3.1.2 Chapter Structure

The following sections summarize the resource options attributes (section 3.2); the resource options potential including DSM (section 3.3); supply-side generation (section 3.4); transmission (section 3.5); and other resources that have potential application in B.C. (section 3.6). This chapter concludes with a description of those resource options that BC Hydro has determined are not viable at this time (section 3.7).

3.2 Resource Options Attributes

Resource options attributes are characteristics that describe a resource option (and can be summarized to describe a portfolio) and are used to assess performance in meeting the IRP planning objectives. Resource options attributes include technical, financial, environmental and economic development.

3.2.1 Technical Attributes

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

- Dependable generating capacity (**DGC**), which is used for non-intermittent resources and is the amount of megawatts (**MW**) a plant can reliably produce when required, assuming all units are in service

[1] BC Hydro’s long-term planning period extends 20 years for DSM and generation resources and 30 years for transmission options.

- Effective load carrying capability (**ELCC**), which is used for intermittent or variable generation resources and is the maximum peak load (measured in MW) that a generating unit or system of units can reliably supply such that the loss of load expectation will be no greater than one day in 10 years
- Installed capacity (measured in 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 gigawatt hours (**GWh**) per year
- Average annual energy (measured in GWh/year)
- Monthly per cent of average annual energy.

BC Hydro uses ELCC to represent the capacity contribution from intermittent clean or renewable IPP resources such as wind and run-of-river hydro. This method evaluates wind and run-of-river capability using 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 resources. The incremental ELCC contributions of intermittent clean or renewable resources will decrease as more of these intermittent resources come into service.

A summary of the generation reliability assumptions and methods of determination is presented in Table 3-1.

Table 3-1 Generation Reliability Assumptions and Methods

Potential Generation Resources	DGC and ELCC Assumptions and Methods of Determination	FELCC Assumptions and Methods of Determination
Run-of-River	ELCC: Weighted average of approximately 60 per cent of the forecasted average MW of potential in the December/January period	Region specific factors applied to the average annual energy
Biomass	DGC: 100 per cent of installed capacity for wood-based biomass; 97 per cent of installed capacity for MSW; and 95 per cent of installed capacity for biogas	100 per cent of average annual energy
Wind – Onshore	ELCC: 26 per cent of installed capacity	100 per cent of average annual energy
Wind – Offshore	ELCC: 26 per cent of installed capacity	100 per cent of average annual energy
Geothermal	DGC: 100 per cent of installed capacity	100 per cent of average annual energy
Natural Gas-Fired Generation and Cogeneration	DGC: Varies from 88 per cent to 100 per cent of installed capacity	Based on 90 per cent capacity factor for Combined Cycle Gas Turbine (**CCGT**) and a minimum 18 per cent capacity factor for Simple Cycle Gas Turbine (**SCGT**) [refer to section 6.2]
Site C	DGC: 1,100 MW	4,700 GWh/year
Pumped Storage	DGC: 100 per cent of installed capacity	Not applicable
Wave	ELCC: 24 per cent of installed capacity	100 per cent of average annual energy (same as offshore wind)
Tidal	ELCC: 40 per cent of installed capacity	100 per cent of average annual energy (same as offshore wind)
Solar	ELCC: 24 per cent of installed capacity	100 per cent of average annual energy
Resource Smart (GMS Units 1-5 Capacity Increase)	DGC: 220 MW	To be determined but likely to be small
Resource Smart (Revelstoke Unit 6)	DGC: 488 MW	26 GWh/year
Coal-Fired Generation with CCS	DGC: 75 per cent of installed capacity	100 per cent of average annual energy

Note: Site C value is based on information provided in the Site C Environmental Impact Statement (**EIS**) filed in January 2013 with the Canadian Environmental Assessment Agency (**Agency**) and the B.C. Environmental Assessment Office (**EAO**).

3.2.2 Financial Attributes

- Financial attributes describe the cost of resource options which are as follows: UEC: reflects the levelized cost of a unit of energy[2] from a resource option, in dollars per megawatt hour (**$/MWh**). The values serve as an initial ranking of energy resources for scheduling to fill a load/resource gap.
- UCC: reflects the levelized cost of a unit of capacity[3] from a resource option in dollars per kilowatt per year (**$/kW-year**).

The UEC and UCCs are calculated adopting the annualized cost method, which is unchanged from the 2008 LTAP. Some key assumptions or methods of determination used to develop the financial attributes include:

- Resource options costs are presented in this chapter as UECs and UCCs at the point of interconnection (**POI**)[4] and are not attributed with the additional costs of: (1) delivering resources to the Lower Mainland (BC Hydro's major load centre); (2) firming and integrating intermittent resources; or (3) the costs of meeting potential future greenhouse gas (**GHG**) regulatory requirements. However, these are important cost considerations and therefore the adjusted firm energy UECs are shown in section 3.4.3 and the adjusted costs are factored into the portfolio analysis described in Chapter 6 of the IRP.
- The UECs and UCCs are presented in real dollars as of January 1, 2013 ($2013). A two per cent inflation factor is used in instances where it was necessary to inflate dollar values to $2013.

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[2] Levelized UECs are calculated by taking the present value (**PV**) of the total annual cost of an energy resource and dividing by the PV of its annual average energy benefit. The one exception is for natural gas-fired generation where the divisor is replaced by the firm energy amount, given the potential large discrepancy between the physical capability of a natural gas-fired generation facility and its realistic operations.

[3] Levelized UCCs are calculated by taking the PV of the total annual cost of a capacity resource divided by the resource's dependable capacity.

[4] 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.

Most of the resource options data presented, including UECs or UCCs, are the result of survey-level assessments, with varying levels of confidence that depend on the level of study, and uncertainties related to resource type and cost. The criteria used to define the levels of confidence are summarized in Appendix 3A-1. The level of study was the main driver for assigning the cost uncertainty, and as a result, all of the resource options have a medium or high cost uncertainty assignment, which can change UECs or UCCs from -10 per cent to +40 or 60 per cent, respectively. A summary of the uncertainties for the supply-side resource options is presented in Table 5-20 of Appendix 3A-1. With the exception of Site C, the cost estimates for supply-side resources in this chapter 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. The Site C cost estimate of $7.9 billion has a Class 3 (budget authorization or control) degree of accuracy. The cost classifications are as defined by the Association for the Advancement of Cost Engineering.[5]

Neither the technical attributes listed in section 3.2.1, nor the adjusted or non-adjusted UECs, capture the value of plant dispatchability. Generation from clean or renewable intermittent resources, such as run-of-river hydro or wind, is determined by environmental conditions such as river flows or wind speeds. As a result, intermittent resources cannot be dispatched to run in response to changes in customer demand or market prices. In contrast, non-intermittent resources such as large hydroelectric (Site C), natural gas-fired generation, Resource Smart, and pumped storage are dispatchable, as discussed in section 3.4 . Biomass may also have limited dispatchability, depending on the ability to time the delivery of fuel or store surplus fuel. Differences in the ability to dispatch resources based on customer demand and market prices are largely captured in Chapter 6.

[5] AACE International Recommended Practice No. 69R-12, *Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Hydropower Industry* (January 25, 2013), page 3 of 14.

Weighted Average Cost of Capital

Policy Action No.13 of the B.C. 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 Site C.

The WACC (the overall cost of combined debt and equity capital) used to finance a resource acquisition has been updated from the 2010 ROR. Real cost of capital rates of 5 per cent and 7 per cent are used in determining the UECs of BC Hydro resources and IPP resources, respectively:

- The 6 per cent real cost of capital used in the 2012 Draft IRP[6] was revised in April 2013 to a 5 per cent real rate to reflect an expected long-term reduction in BC Hydro's WACC. The BC Hydro WACC is calculated using a deemed capital structure of a 70 per cent debt and 30 per cent equity. The forecasted cost of debt is provided by the B.C. Ministry of Finance and the cost of equity is based on BC Hydro's allowed rate of return. The 5 per cent real rate corresponds to a 7 per cent nominal rate, using an average rate of inflation of 2.0 per cent.[7]
- Based on its experience with IPPs and other third-party developers, BC Hydro uses a WACC of 7 per cent (real) for IPPs for the purpose of resource costing. A 2 per cent WACC differential was established in the Site C EIS, where a 6 per cent real rate was used for BC Hydro compared to an 8 per cent real rate for IPPs. Given that the recent lowering of borrowing costs is applicable to both the public and private sectors, the estimated IPP WACC was reduced from 8 per cent real to 7 per cent real. The WACC differential is attributable to BC Hydro's role as an agent of the Province of B.C. in that its borrowing is

[6] BC Hydro revised its F2014 WACC by 50 basis points in April 2013. Prior to this change, BC Hydro's WACC was at 5.5 per cent (real), which was rounded up to 6 per cent for the purpose of long-term planning.

[7] Financial forecasts of Consumer Price Index (**CPI**) and Canadian long-term interest rate are provided by the Treasury Board of the Province of B.C.

guaranteed by the Province and BC Hydro can also borrow directly from the Province.

- In its 2006 Integrated Electricity Plan/Long-Term Acquisition Plan (**LTAP**) Decision (page 205), the BCUC found that the cost of debt for IPPs is higher than BC Hydro's debt cost:

> "…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, <u>*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*</u>." [Emphasis added].

This BCUC finding is supported by BC Hydro's observations based on open-book Electricity Purchase Agreement (**EPA**) negotiations. Furthermore, in a study for the Western Electricity Coordinating Council (**WECC**) an after-tax WACC for IPPs of 8.25 per cent was used.[8]

3.2.3 Environmental Attributes

Environmental attributes provide high-level information on the environmental footprint of the resource options. To develop the environmental attributes used in the IRP, BC Hydro retained the services of Kerr Wood Leidal Associates Ltd., Hemmera Envirochem Inc. and HB Lanarc. The environmental attributes were selected based upon the following criteria:

- Appropriate for provincial-scale portfolio comparisons
- Science-based and defendable

8 "Cost and Performance Review of Generation Technologies – Recommendations for WECC 10- and 20-Year Study Process", 2012, Energy + Environmental Economics, page 55 to 56.

- Measurable in a quantity-based approach that facilitates comparison between portfolios of resource options
- 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 developed were grouped into four environmental categories – land, atmosphere, freshwater and marine – and were further broken down into indicators as described in Table 3-2.

Table 3-2 Environmental Attributes

Environmental Category	Indicator	Unit of Measure	Classifications
Land	Net Primary Productivity (gC/m^2/year)[9]	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	Greenhouse Gas Emissions	tonnes/GWh	Carbon Dioxide equivalent (**CO_2e**)
	Air Contaminant Emissions	tonnes/GWh	Sulphur Dioxide
			Oxides of Nitrogen
			Carbon Monoxide
			Volatile Organic Compounds

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

Environmental Category	Indicator	Unit of Measure	Classifications
			Fine Particulates: PM[10] 2.5 (reported when data is available)
			Fine Particulates: PM 10 (reported when data is available)
			Fine Particulates: PM Total
			Mercury
Freshwater[11]	Reservoir Aquatic Area[12]	ha	Site C (Pumped Storage and Resource Smart if applicable or available)
	Affected Stream Length[13]	kilometres (**km**)	Run-of-river and Site C (Pumped Storage and Resource Smart if applicable/available)
	Priority Fish Species (number of priority fish[14] 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)
Marine[15]	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

These high-level environmental footprints are appropriate for comparison of resource options across provincial-scale portfolios. Since detailed site-specific information is unknown for the majority of the potential sites in the database, these environmental attributes are not appropriate, or intended to be used, for individual

10 PM = particulate matter.

11 Same as the 2010 ROR; the freshwater attribute to address the riparian footprint was dropped due to lack of data for potential run-of-river sites and pumped storage which would have made the comparisons ineffectual.

12 “Reservoir Aquatic Area” is an indicator specifically applicable to Site C.

13 “Affected Stream Length” is an indicator applicable to run-of-river projects and Site C.

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

15 Same as the 2010 ROR; the marine attribute of bathymetry, which is a descriptor of water depth, was not used for IRP purposes given that it added negligible value compared with the other two marine attributes.

site-specific resource option evaluations and comparisons. For additional information on the environmental attributes of individual resource options refer to Appendix 3A-3 of the IRP. For information on the environmental footprint of resource portfolios refer to Chapter 6.

3.2.4 Economic Development Attributes

Economic development attributes describe the contributions that resource options make to the provincial economy. The economic development attributes selected are categorized into three groups: Provincial gross domestic product (**GDP**), employment, and Provincial Government revenue. These groups are further broken down into sub-categories as described in Table 3-3.

Table 3-3 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[16]	Direct
			Indirect
			Induced
Provincial Government Revenue	Construction/Operation	$ and $/year	Direct
			Indirect
			Induced

For additional information on the economic development attributes of individual resource options, refer to Appendix 3A-5. For information on the contributions of resource portfolios to economic development refer to Chapter 6.

16 "Jobs" is also referred to as person years. This measure reflects the average jobs in the affected industries and may not always be defined as full-time employment. In general, construction jobs are shorter-term and higher in number, whereas operating jobs are longer-term and last for the life expectancy of the project.

3.3 Demand Side Management Options Summary

Section 1 of the *CEA* defines DSM (referred to as 'demand-side measures'*)* 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."

BC Hydro's DSM tools focus on conserving energy, promoting energy efficiency and other measures to reduce the customer demand that BC Hydro must serve. Capacity-focused options are designed to deliver additional capacity savings during BC Hydro's peak load periods through voluntary programs that manage and control customers' electricity demand rather than energy consumption.

Two sets of DSM options were developed for the 2010 ROR: (a) five energy and capacity options (DSM Options 1 through 5); and (b) two capacity-focused options (industrial load curtailment and capacity-focused programs).

As described below in section 3.3.1, the 2013 ROR Update provides a targeted update to energy and capacity Options 1, 2 and 3 to reflect new information including: economic/market conditions, customer participation, load forecast and economic conservation potential. Options 1, 2 and 3 have the same parameters as in the 2010 ROR:

- BC Hydro's current DSM target of 7,800 GWh/year and 1,400 MW is DSM Option 2, which was built from the DSM targets established in the 2008 LTAP
- Option 1 continues to be designed to meet the *CEA* subsection 2(b) objective of reducing BC Hydro's expected increase in electricity demand by 2020 by at least 66 per cent

- Option 3 continues to target more electricity savings than Option 2 by expanding program efforts while keeping the level of activity for codes and standards, and conservation rate structures, consistent with Option 2

Energy and capacity Options 4 and 5 and capacity-focused options were not updated for the 2013 ROR Update, because they are not viewed as being viable for long-term planning purposes at this time; refer to section 3.7.

The five energy and capacity options are created as integrated packages of DSM tools that are interrelated and employed in concert to achieve a particular path of energy savings over time. The specific tools include codes and standards, conservation rate structures and programs.

- Codes and standards are public policy instruments enacted by governments to influence energy efficiency. Examples include building codes, energy efficiency regulations, tax measures, and local government zoning and building permitting processes.
- Conservation rate structures are inclining block (stepped) rate structures. BC Hydro has conservation rates in place (or planned for implementation) for over 90 per cent of its domestic load. Over the past seven years, BC Hydro implemented four conservation rate structures for residential, commercial, and industrial customers.
- Programs are designed to support codes and standards and rate structures, as well as to address the remaining barriers to energy efficiency and conservation after codes and standards and rate structures, thereby capturing 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 self-generation.

In addition to these tools, there are a number of supporting initiatives – public awareness and education, community engagement, technology innovation, 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 options employ all of the tools described above, albeit at different intensities of activity. The options were also developed in consideration of a strategic framework where DSM initiatives can be targeted to different contexts: individual, market and social.

3.3.1 DSM Updates

Options 1, 2 and 3 have been updated to reflect new information on the cost and energy savings performance of the DSM tools (codes and standards, conservation rate structures, programs) and supporting initiatives.

As part of the first component of the update, BC Hydro updated the savings potential to reflect new information, including economic/market conditions, customer participation and a reduced 2012 mid Load Forecast as compared to the 2010 mid Load Forecast. In the 2008 LTAP proceeding, BC Hydro provided evidence that a reduced load forecast impacts DSM economic potential.[17] For example, it is generally acknowledged that industrial DSM participation and energy efficiency will increase during economic growth and decrease in recessionary periods.[18] In addition, different industries have varying economic and technical potential to provide DSM based on specific equipment and processes.

The second component of the update looked at whether there was an ability to make adjustments to the DSM level of activity in the near term. As part of its portfolio cost management efforts, BC Hydro is interested in understanding how expenditures could be reduced in the near term while still retaining the ability to ramp back up to achieve longer-term energy savings targets (i.e., Alternative Means). DSM programs and supporting initiatives are more flexible in the near term than codes and

[17] Exhibit B-10 in the 2008 LTAP proceeding, section 2.4.2.
[18] Refer, for example, T.Ernst and O.Dancel, "Macroeconomc Impacts on DSM Program Participation", 2011 ACEEE Summer Study on Energy Efficiency in Industry), page 1-81.

standards and conservation rate structures; therefore adjustments were targeted to programs and supporting initiatives (i.e., in other words, codes and standards and conservation rates were not reduced). BC Hydro explored DSM Options 1, 2 and 3 for the potential to be adjusted in the near term. BC Hydro revised Option 1 and Option 2 to reflect lower levels of expenditures in the near term. The framework used to arrive at these lower levels of expenditures in the near term is described in Chapter 4. A version of Option 3 with near term reductions was not included in the analysis. Option 3 would only be selected if needed to fill the resource gap beyond Option 2. If that higher resource level was required, BC Hydro would not reduce Option 3 expenditures in the near term due to the deliverability risk in recovering to Option 3 savings levels (uncertainty with the ramp rate assumptions).

The next sections provide a description of Options 1, 2, 3, 4 and 5, with their energy and capacity savings shown in Figure 3-1 and Figure 3-2, respectively. These options are described in comparison to Option 2, which is BC Hydro's recommended DSM target.

3.3.1.1 Option 1

In the 2010 ROR, Option 1 was developed explicitly to meet 66 per cent of the forecasted load growth with DSM, which would be the minimum required to meet the *CEA* objective of reducing BC Hydro's "expected increase in demand for electricity by the year 2020 *by at least* 66%" [emphasis added]. The planning parameter for the updated Option 1 is similar to those in the 2010 ROR: that is, reduce expected load growth by at least 66 per cent in F2021, and on average for the remaining portion of the planning period (F2022 to F2032). The updated Option 1 targets 6,100 GWh/year of energy savings and 1,200 MW of associated capacity savings by F2021.

At the time of the 2010 ROR, the calculation of the amount of DSM required to reduce the expected increase in demand for electricity by F2021 by at least

66 per cent was based on the 2010 Load Forecast. Based on the 2012 mid Load Forecast[19] (the reference forecast for the 2013 IRP), load growth has declined such that a lower level of energy savings is required in F2021 to reduce the expected increase in demand by at least 66 per cent. Accordingly, BC Hydro updated Option 1 with the new load forecast information.

Option 1 also reflects adjustments to near-term expenditures to reflect the lowest level of DSM possible while still being able to ramp up to meet the *CEA* objective of reducing load growth by at least 66 per cent in F2021. By F2016, expenditures are reduced to a base level of $100 million. In F2021, energy savings just meet the 66 per cent objective. The level of near-term expenditures is lower than in Option 2. To reach this lower level of expenditures, additional adjustments were made to programs and supporting initiatives in the following areas:

- Residential – Expenditures are reduced by a further 12 per cent by F2016 relative to Option 2 through targeted reductions to a few programs
- Commercial – Program expenditures are reduced by a further 24 per cent by F2016 through limiting participation and reducing program costs for most programs
- Industrial – Relative to Option 2, program expenditures are reduced by 22 per cent in F2016 and 29 per cent in F2017. These reductions are achieved through lower levels of activity in the load displacement program and other programs
- Supporting Initiatives – An additional reduction of 19 per cent by F2016 was made to supporting initiative expenditures

3.3.1.2 Option 2

In the 2010 ROR, Option 2 was an updated version of the DSM Plan that was included in BC Hydro's 2008 LTAP filing with the BCUC. The updated Option 2

19 Not including load from Liquefied Natural Gas (LNG).

target continues to be the 2008 LTAP target, which is 7,800 GWh/year of energy savings and 1,400 MW of associated capacity savings by F2021.

As set out in section 3.3.1, Option 2 was first updated to reflect new information, such as the 2012 mid Load Forecast and current economic conditions. This provided a new baseline for the energy savings potential for Option 2.

In addition, BC Hydro wanted to maintain the 2008 LTAP DSM target over the long term while exploring whether expenditures could be adjusted in the near-term to manage energy portfolio costs. The framework used to examine reductions is described in Chapter 4.

The following parameters were used to modify DSM Option 2 for IRP purposes:

- First, reduce expenditures in the near term (F2014-F2016) and by doing so, reduce energy savings as well
- Second, ramp up to generally return to LTAP energy savings levels by F2021
- Third, generally remain at the LTAP energy savings levels post-F2021 within +/- 10 per cent[20]

The near-term adjustments result in a reduction of $230 million (46 per cent for F2015 and F2016) relative to the DSM Plan in the F2012-F2014 Revenue Requirements Application and approximately $330 million by F2022 in expenditures relative to the update to the Option 2 baseline described above. For the balance of the IRP, the DSM reductions are described in relative terms to the update to the Option 2 baseline (see the discussion in Chapter 4 on the Alternative Means to reach the DSM target). This reduction is reflected in the portfolio analysis presented in Chapter 6 and in the Recommended Actions in Chapter 9.

With regard to the specific tactics employed for DSM Option 2:

[20] Minor variances from LTAP energy savings levels (generally in the order of +/- 10 per cent) can be expected from year to year because they are P50 estimates. Refer to Chapter 4 for more information on the risk assessment process.

- Codes and standards are those that have been enacted, announced or planned by the federal or provincial governments
- Conservation rate structures are those that are in place or planned. These include the Transmission Service Rate (**TSR**) for large industrial customers, the Residential Inclining Block (**RIB**) rate for residential customers, a conservation rate structure for large commercial and small industrial customers in the former Large General Service (**LGS**) rate class, and a conservation rate structure for the Medium General Service (**MGS**) rate class
- Programs target residential, commercial and industrial customer classes. Programs were the primary lever for determining the near-term adjustments. The specific adjustments are provided in Table 3-4.
- Supporting initiatives expenditures are reduced over the near term to align with program levels of activity. Activities are re-prioritized to focus on understanding the potential for new energy efficient technologies over the longer term.

Table 3-4 Near-Term Program Adjustments for Option 2

Program	Near-Term Adjustments
Residential	
Refrigerator Buy-Back	· Reduce market presence in F2014 · Return to market in F2020
Lighting Appliances Electronics	· Combine the programs into a new Retail Program that targets the three product categories on a rotation basis and at a significantly reduced expenditure level
New Home	· Assess whether program can be extended cost-effectively · If program is not extended, maintain developer education component (through codes and standards) to enhance code compliance and builder/developer relationship
Smart Meter Infrastructure In-Home Feedback (Web Portal & In-Home Devices)	· Defer in-home display · Continue to support Web Portal
Low Income	· Maintain provision of energy savings kits · Maintain current participation levels in Energy Conservation Assistance Program, while looking for process improvements

Program	Near-Term Adjustments
Commercial	
Power Smart Partner and Product Incentive Program (**PIP**)	· Continue with both programs but combine application process and IT infrastructure · Cap incentive funding · Reduce funding for energy study and energy managers. · Eliminate screw-in category and short savings persistence opportunities · Continue existing continuous optimization activities but reduce new participants · Offer future continuous optimization contract renewals for a shorter term to maintain flexibility and limit new growth · Defer customer Voltage and VAR Optimization opportunities
New Construction	· Continue with program but find cost reductions · Eliminate short persistence technologies
Lead By Example	· Reduce employee engagement and re-scoped projects · Maintain policy activities
Industrial	
Power Smart Partner – Transmission	· Screen projects with incentives over $1 million; eliminate incentive offers over $5 million · Cap incentive offer · Cap annual incentive funding and energy managers
Power Smart Partner – Distribution	· Eliminate least cost-effective end uses and short persistence projects · Cap incentive funding · Increase performance metrics for energy managers
Load Displacement	· Continue with committed projects · Defer new projects to F2019

Finally, the energy savings for revised DSM Option 2 were adjusted for uncertainty. Information on the adjustment process can be found in Chapter 4.

3.3.1.3 Option 3

In the 2010 ROR, DSM Option 3 was constructed to target more electricity savings by expanding program efforts, while keeping the level of activity and savings for codes and standards and conservation rate structures the same as Option 2. Program activities were expanded with increased incentives, advertising or technical support to address customer barriers, thereby increasing customer participation. For the 2013 IRP, Option 3 is based on a similar construct. Program activity was expanded based on allowing program incremental cost-effectiveness to increase beyond BC Hydro's current Long Run Marginal Cost.

The updated Option 3 targets 8,300 GWh/year of energy savings and 1,500 MW of associated capacity savings by F2021. As set out in section 3.3.1, BC Hydro's updated Option 3 reflects new information. Codes and standards and conservation rate structures reflect the same level of activity as updated Option 2 described in section 3.3.1.2.

3.3.1.4 Options 4 and 5

DSM Options 4 and 5 were designed in collaboration with BC Hydro's Electricity Conservation and Efficiency Advisory Committee and were intended to look at a fundamental shift in BC Hydro's approach to saving electricity. These options place much greater emphasis on tactics that change market parameters and societal norms and patterns that influence electricity consumption and conservation. As new and untested approaches to saving electricity, both Option 4 and Option 5 are subject to considerable uncertainty regarding government, customer and BCUC acceptance and, ultimately, their effectiveness at generating additional cost-effective electricity savings.

BC Hydro did not update Options 4 and 5 at this time because they are currently not technically feasible options; refer to section 3.7.

Option 4

DSM Option 4 is founded on new or more aggressive conservation rate structures, and significant government regulation in the form of codes and standards, to generate additional savings. Option 4 targets about 9,500 GWh/year of energy savings and 1,500 MW of associated dependable capacity savings by F2021. Large industrial customers would be exposed to a much larger extent to marginal cost price signals because the Transmission Service Rate would change from a 90/10 to an 80/20 split between Tier 1 and Tier 2 prices, thereby increasing the amount of energy consumption that is subject to Tier 2 pricing. 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 higher marginal rates. Commercial customers would be subject to efficiency-based pricing through either a connection fee tied to building energy performance, or an initial baseline rate structure for new buildings. Rate structures would need to be tied to a house or building's rated energy performance.

Option 5

Option 5 is the most aggressive DSM resource option considered by BC Hydro. Option 5 targets about 9,600 GWh/year of energy savings and 1,600 MW of associated dependable capacity savings by F2021. This option aims to create a future 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 are pervasive throughout society and ingrained in a business decision-making culture. This shift is reflected through wide-spread district energy systems and micro-distributed generation; smaller, more efficient housing and building footprints; community densification; distributed workforce and hoteling (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 contributes to the culture shift. All BC Hydro customers would be exposed to marginal cost price signals to a greater extent. For the industrial sector, a market transformation to certified plants occurs, supported with expanded regulation.

3.3.2 Capacity-Focused Options

While the five DSM options described above generate associated capacity savings, additional capacity savings may be achievable through capacity-focused DSM, which specifically targets capacity savings. The capacity-focused options were not updated for this IRP; however, BC Hydro recommends implementing a voluntary industrial load curtailment program during F2015 to F2018 to determine how much capacity savings can be acquired and therefore relied upon over the long term.

This represents BC Hydro's first major exploration of capacity-focused DSM and as a result, experience will need to be gained to increase certainty of the expected electricity savings. For capacity-focused DSM, two options[21] were considered. These options are constructed of building blocks that could be sequentially selected in combination with each other:

- Industrial Load Curtailment: This option targets large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods. BC Hydro implemented a load curtailment program targeted at shorter term (one to three years) operational 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 a longer term.
- Capacity-Focused Programs: This 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-focused programs include load control of water heaters, heating, lighting and air conditioning. The participation rate and savings per participant are key aspects of the uncertainty of capacity savings.

[21] At the time of the 2010 ROR development BC Hydro also considered Time-Based Rates as a category of capacity resource option; since then, in accordance with government policy, BC Hydro has no plans to implement Time-Based Rates to address capacity requirements for residential and commercial customers. With respect to industrial customers, by letter dated June 19, 2013 the B.C. Minister of Energy and Mines asked the Industrial Electricity Policy Review (**IEPR**) Task Force to "review current models of industrial 'Time of Use' pricing from relevant jurisdictions and comment on their effectiveness and applicability in [B.C.]. This review is to stay strictly within the bounds of industrial customers only …". BC Hydro awaits the final recommendations of the IEPR Task Force and the government's response.

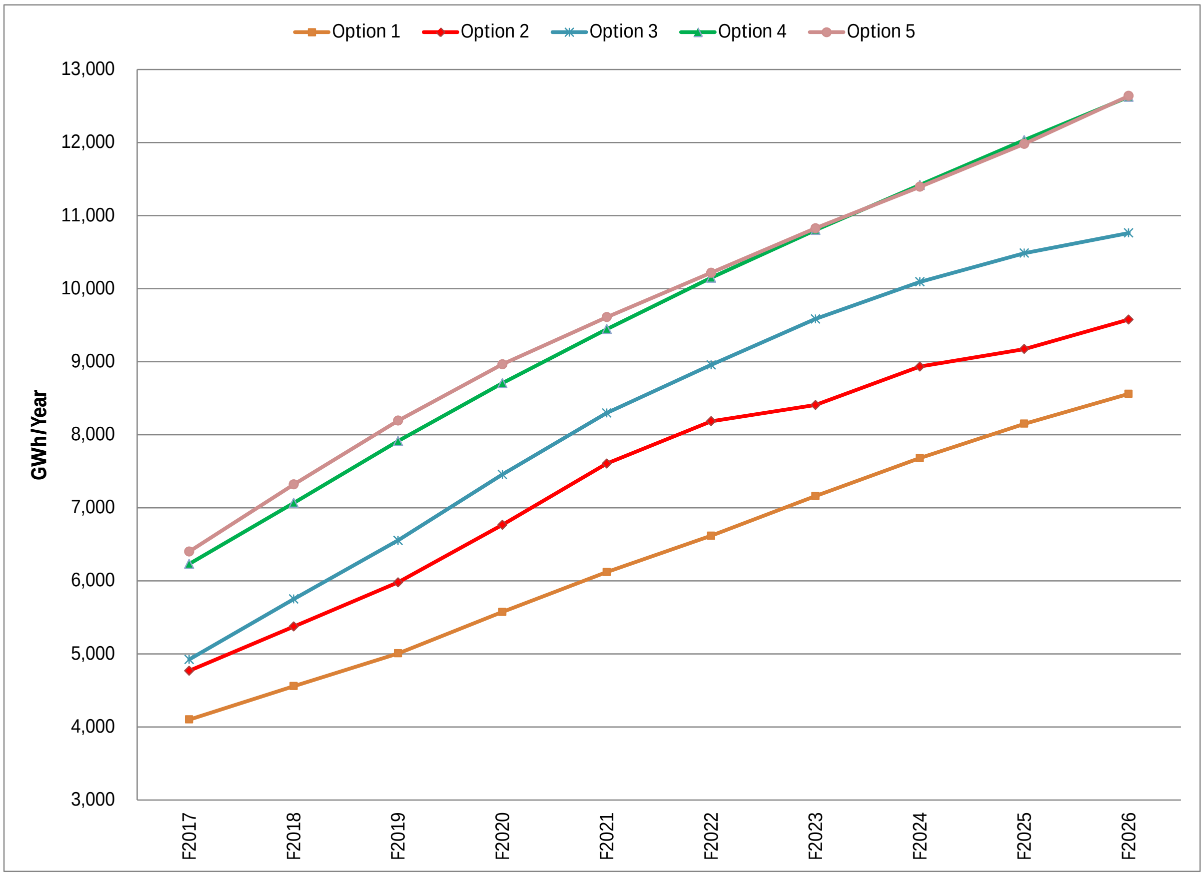
1 ### 3.3.3 Summary of DSM Options

2 This section provides a summary and comparison of the energy and capacity DSM
3 options on a cost, energy savings and capacity savings basis.

4 #### *3.3.3.1 Summary of Energy DSM Options 1 to 5*

5 Figure 3-1 compares the energy savings obtained from Options 1 to 5 over the time
6 horizon of the analysis.

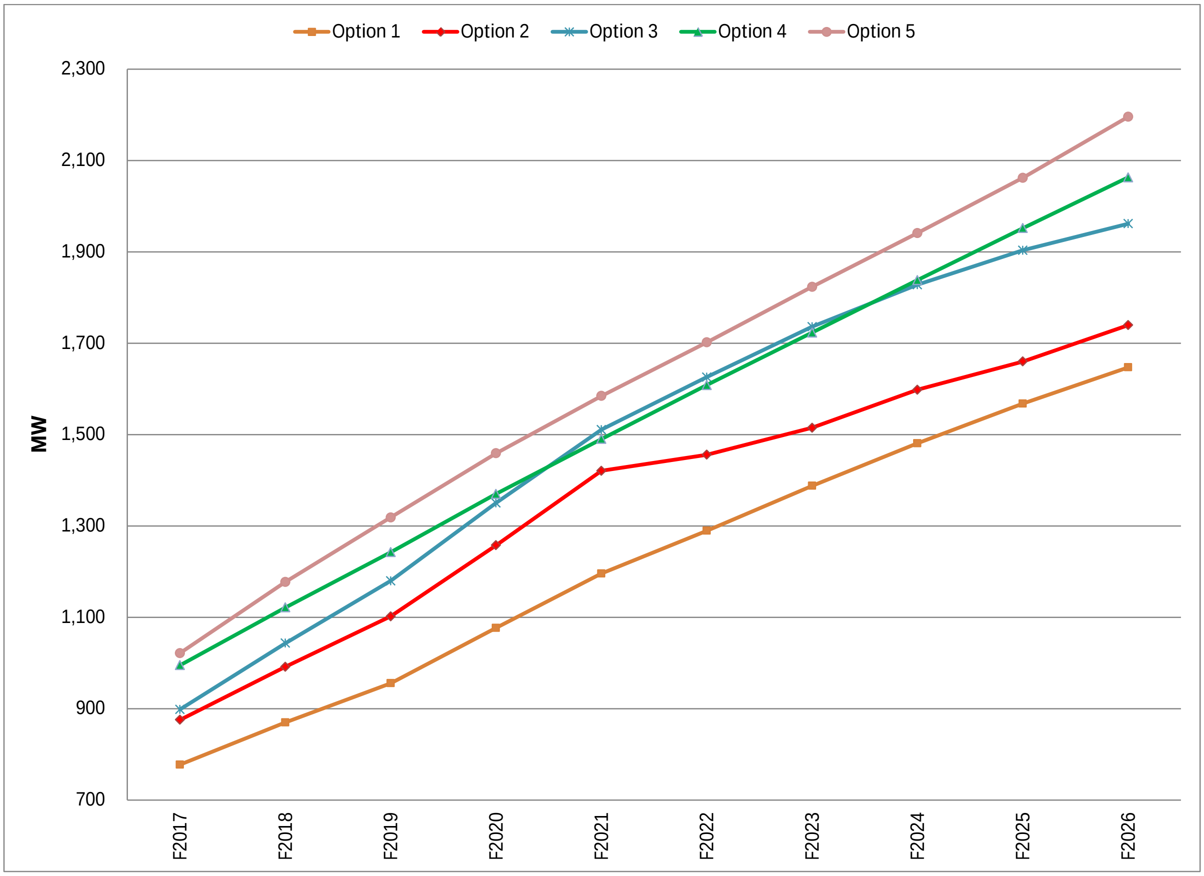
7 **Figure 3-1 DSM Energy Savings**[22]



8 The associated capacity savings from Options 1 to 5 are provided in Figure 3-2.

[22] The energy savings shown for Options 1 through 5 have been adjusted for uncertainty.

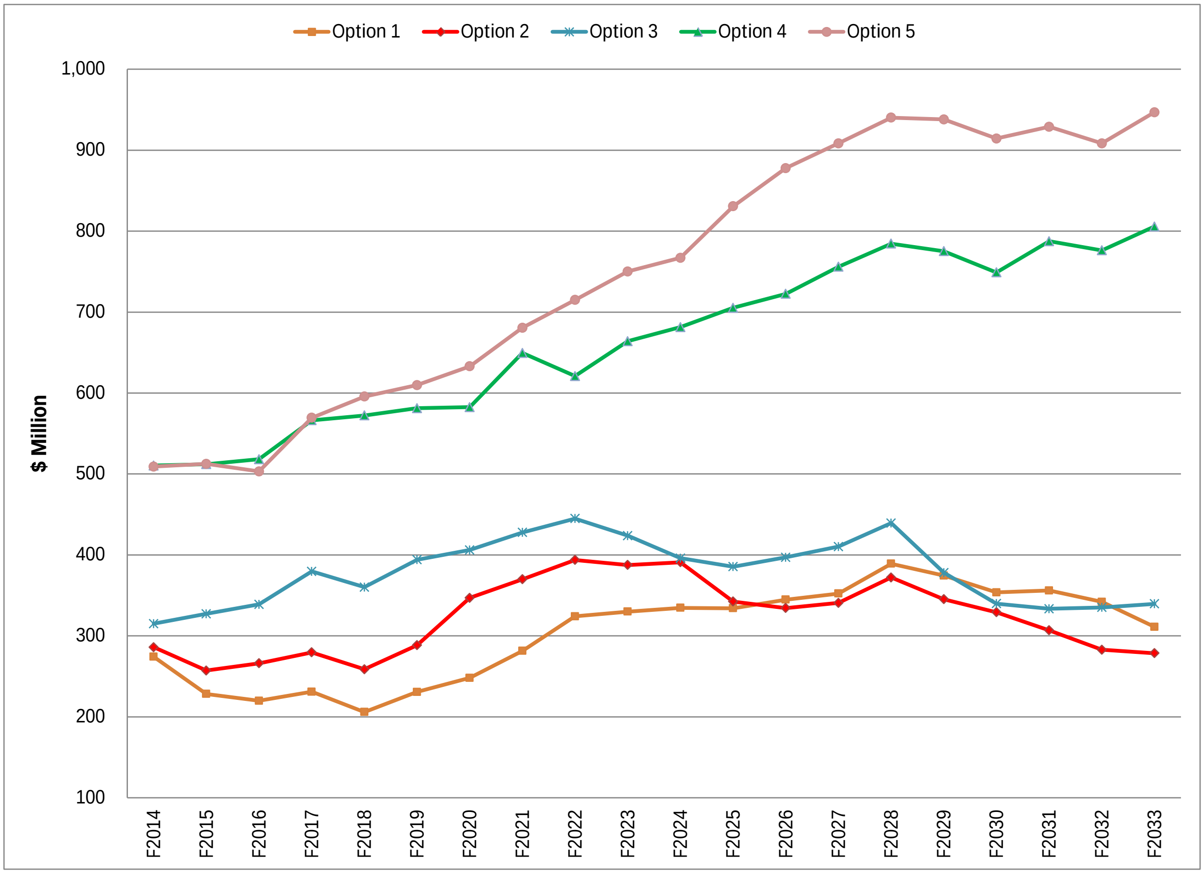
1 **Figure 3-2 DSM Associated Capacity Savings**[23]



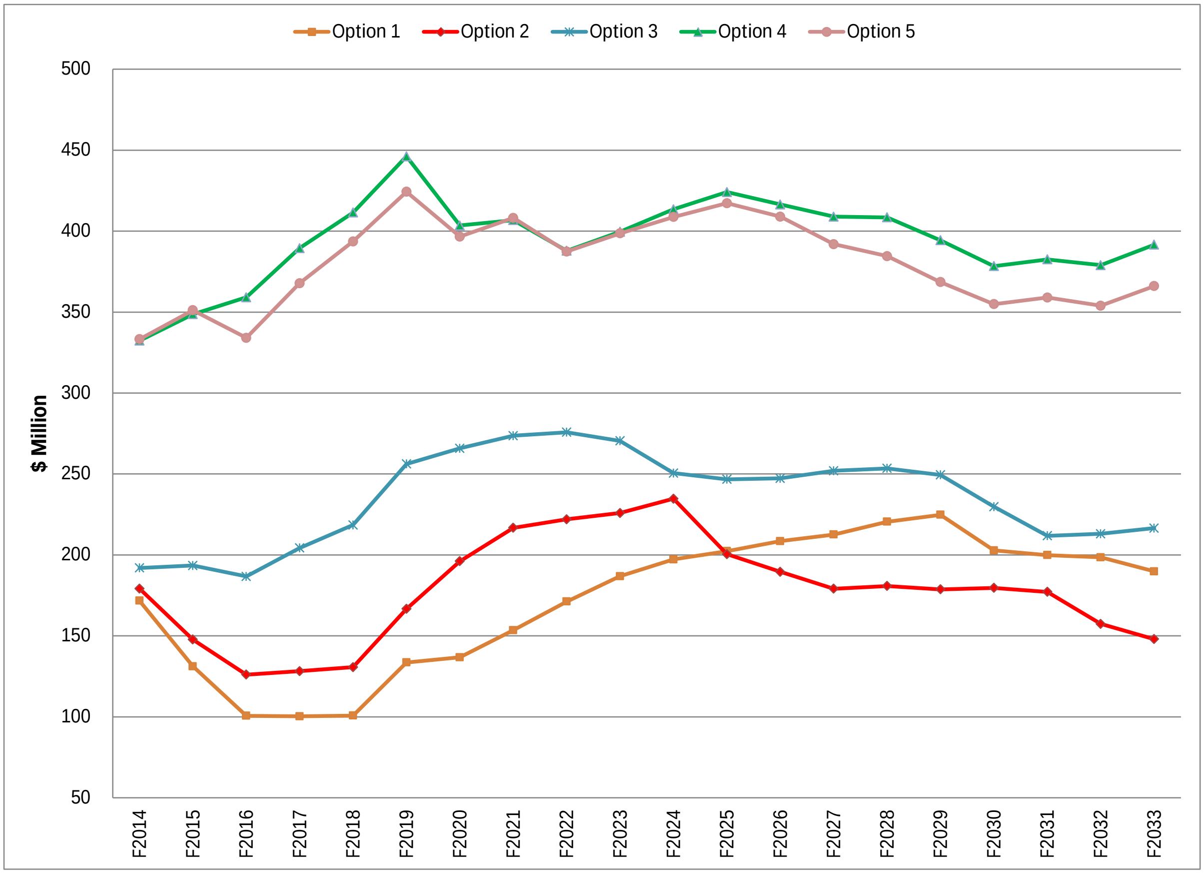
2 Figure 3-3 shows the resource investment (total resource costs or TRC) in DSM for
3 the various options, and Figure 3-4 shows the corresponding utility cost (**UC**) for the
4 various options.

[23] The capacity savings shown for Options 1 through 5 have been adjusted for uncertainty.

1 **Figure 3-3 Total Resource Costs**



1 **Figure 3-4 Utility Costs**



2 The UECs from TRC (gross TRC, i.e., cost before netting of any benefits) and UC
3 perspectives for each of DSM Options 1 to 5 are provided in Table 3-5. The TRC
4 cost-effectiveness test is described below in section 3.3.4.1.

5 **Table 3-5 TRC and UC for DSM Options 1 to 5**

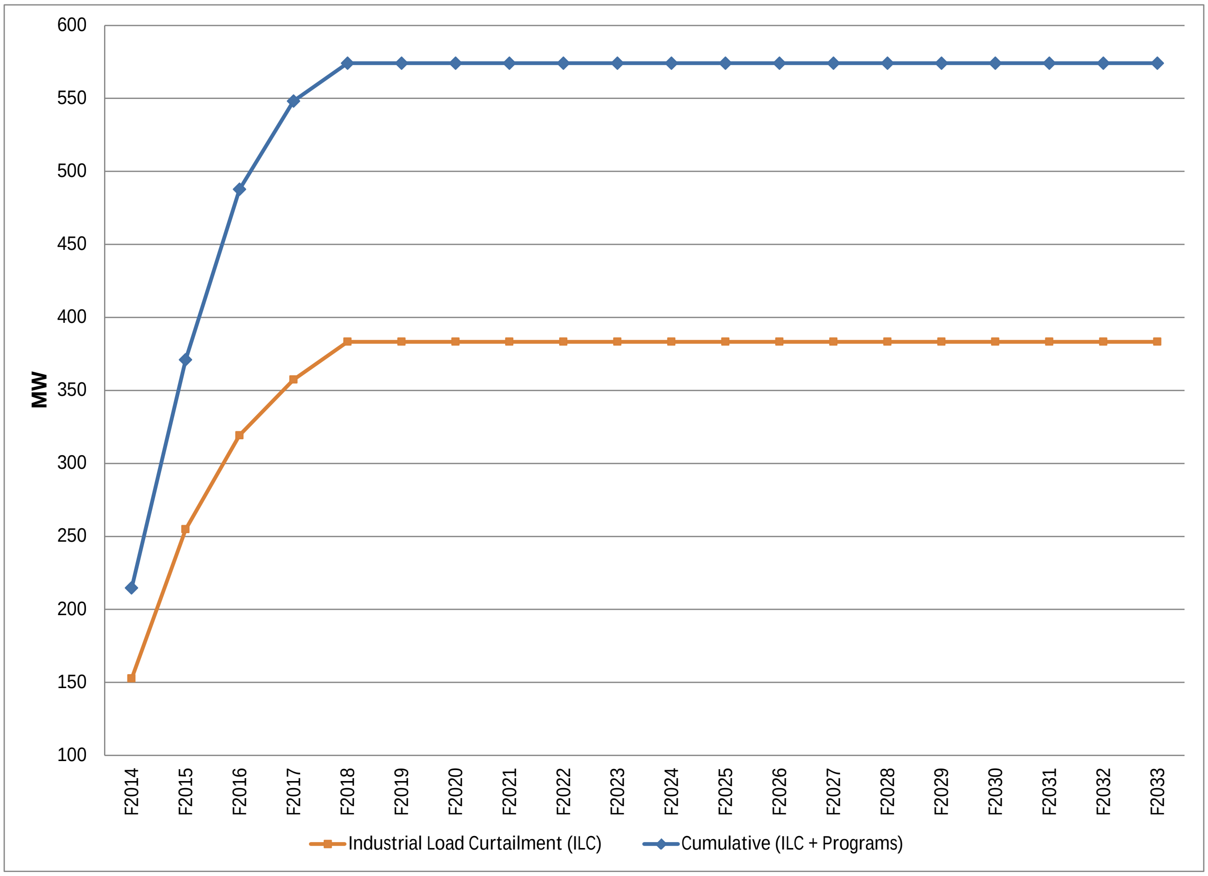
DSM Option	TRC ($/MWh)	UC ($/MWh)
1	32	18
2	32	18
3	35	22
4	47	30
5	49	29

6 Note: Includes transmission and distribution loss savings estimates.

3.3.3.2 Summary of Capacity-Focused DSM Options

The capacity-focused DSM options are summarized in Figure 3-5. While the capacity programs are independent, the curves for each option are shown on a cumulative basis to provide an overview of the potential combined savings.

Figure 3-5 Cumulative Capacity Savings



The UCCs from TRC and UC perspectives for the two capacity-focused DSM options are provided in Table 3-6.

Table 3-6 TRC and UC for Capacity-Focused DSM

Capacity-Focused DSM Option	TRC* ($/kW-year)	UC* ($/kW-year)
Industrial Load Curtailment	31	45
Capacity-Focused Programs	55	69

* Includes transmission and distribution loss savings estimates.

3.3.4 Additional DSM Information

3.3.4.1 DSM Cost-Effectiveness Tests and DSM Benefits

As described in section 1.2.1, subsection 3(1) of the *CEA* requires that BC Hydro submit an IRP to the Minister "that is consistent with good utility practice". Consistent with good utility practice, among other things BC Hydro is guided by the TRC and UC tests as described by the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*,[24] (**California Standard Practice Manual**) to screen DSM. BC Hydro identifies the cost and benefit components and cost-effectiveness calculation procedures for DSM as follows:

- The TRC measures the overall economic efficiency of a DSM initiative from a resource options perspective, including both participant and utility costs. In addition to the benefits of avoiding supply-side electrical energy costs, the California Standard Practice Manual and many other jurisdictions also recognize that DSM results in a range of other benefits, such as a reduction in electrical capacity costs (i.e., capacity at the generation, bulk transmission, regional transmission and distribution level), specific non-energy benefits (e.g., operation and maintenance savings resulting from the installation of an energy efficient measure) and avoided participant costs aside from electric utility bills (such as natural gas savings) –Inclusion of these benefits increases the cost-effectiveness of DSM. BC Hydro presents the gross TRC (i.e., cost before netting of any benefits) in Chapter 3, and net TRC (i.e., cost net of various benefits) in chapters where applicable. Refer to section 6.3.3 for a description of the TRC used in portfolio analysis.
- The UC measures the costs of the DSM initiative from the utility's perspective, excluding any costs of the participant. The benefits are similar to the TRC utility benefits (avoided supply costs and capacity). The UC test result indicates the change in total utility bills (revenue requirements) due to DSM.

[24] October 2001; available at the California Energy Commission's website at www.energy.ca.gov.

The BCUC has determined that individual programs should be assessed to determine if they pass a TRC benefit/cost ratio of 1.0, and that those programs with a TRC ratio of less than 1.0 must be justified. Refer to section 9.2.1 for this analysis.

The BCUC's determination of DSM cost-effectiveness is also guided by the Demand-Side Measures Regulation[25] (**DSM Regulation**). The DSM Regulation contains among other things modifications to the TRC test (referred to as the **modified TRC**) that the BCUC must follow when assessing DSM expenditure schedules submitted by public utilities pursuant to subsection 44.2(1)(a) of the *Utilities Commission Act*. The DSM Regulation provides a deemed value for natural gas savings and a deemed non-energy benefit adder of 15 per cent. The application of the DSM Regulation will be addressed in BC Hydro's F2014-F2016 DSM expenditure filing with the BCUC.

3.3.4.2 DSM Amortization Period

The IRP analysis uses the DSM amortization period to annualize DSM costs such that costs are aligned with realized DSM savings. Consistent with section 1(vi) of BCUC Order No. G-77-12A dated June 20, 2012[26], the DSM amortization period has been changed from a 10-year to a 15-year period. The IRP portfolio analysis reflects the updated 15-year amortization period.

[25] B.C. Reg. 326/2008 (including amendments up to B.C. Reg. 228/2011).

[26] Order reflects Direction No. 3 to the BCUC issued by the Lieutenant Governor in Council on May 2, 2012 with respect to BC Hydro's F2012 to F2014 Revenue Requirements Application.

3.3.4.3 Elasticity

In generating the conservation estimates for residential and non-residential customer conservation rate structures BC Hydro continues to use a year-over-year elasticity estimate of -0.1.[27] The -0.1 elasticity has been derived from a third party consultant review of other comparable low cost winter peaking jurisdictions. The -0.1 price elasticity is reasonable for forecasting the demand impacts of year over year expected changes in electricity prices; separate estimates of conservation induced by both DSM programs and changes in government codes and standards are generally additive to produce a net load forecast after DSM.

The topic of elasticity was addressed as part of BC Hydro's 2008 LTAP proceeding. BC Hydro retained consultant Energy and Environmental Economics Inc. (**E3**) to provide a recommendation with respect to price elasticity estimates. E3 provided the following recommendations to the 2008 LTAP:

- BC Hydro should use a single year-over-year price elasticity for forecasting rate-induced conservation for each year, with separate accounting for the longer term impacts of changes to government codes and standards and BC Hydro DSM programs
- BC Hydro should adopt a price elasticity estimate of -0.1 to estimate the aggregate impact of rate changes for residential and non-residential customers[28]
- It is reasonable for BC Hydro to use -0.05 as the price elasticity estimate for decomposing the total rate-induced conservation impact into rate increase-

[27] One exception is the TSR, where electricity savings are not derived from an elasticity estimate, but on a customer-by-customer basis. Due to the uniqueness of the customer operations within the transmission voltage class, the use of a generic elasticity value to estimate savings from TSR would not be appropriate. Instead, the TSR savings forecast is separated into three general categories: incremental self-generation, load aggregation and other savings. For customers with self-generation, a forecast of incremental self-generation beyond customer-specific generation baselines and other contractual obligations is made. Load aggregation provides customers with multiple sites the ability to shift production or processes from less efficient sites to more efficient sites. An estimate is made in this efficiency gain in the form of energy savings as a result of load aggregation. The "others" category is based on assumptions in operational improvements incented by the rate structure.

[28] Orans, R. Direct Testimony, Appendix E to the 2008 LTAP, section 3, pages 14 to 21.

induced and conservation rate structure-induced conservation. Separation of rate increase-induced and conservation rate structure-induced savings was done so rate impacts are: (1) accounted for and appropriately allocated between DSM and natural conservation caused by rate increases; and (2) not double counted. The -0.05 price elasticity estimate is used in the December 2012 Load Forecast.

E3's recommendation of the use of the -0.1 price elasticity estimate is based on E3's comprehensive review of published studies of measured price response results from jurisdictions most comparable to B.C. These studies were drawn from a comprehensive, industry-wide review of over 100 residential and 60 non-residential price elasticity studies:

- E3 found that the four residential studies[29] most comparable to B.C. – for Washington State, Wisconsin, Bonneville Power Administration[30] (**BPA**) and Ontario – report elasticity estimates of between zero and -0.28 with three of the four studies reporting estimates below -0.1

[29] M. Bernstein and J, Griffin (2005), "Regional Differences in the Price-Elasticity of Demand for Energy", pages 82 to 84 (Washington State; data sample is annual consumption by state for 1977-2004, elasticity of -0.079); J. Herriges and K. King (1994), "Residential Demand for Electricity Under Block Rate Structures: Evidence from a Controlled Experiment", Journal of Business and Economic Studies, 12(4), pages 419 to 430, table 4 (Wisconsin; data sample is monthly billing for rate experiment for 1500 customers in 1984-85,summer elasticity of -0.02 and winter elasticity of -0.04); C. Hsiao and D.C. Mountain (1994), "A Framework for Regional Modelling and Impact Analysis: An Analysis for the Demand of Electricity by Large Municipalities in Ontario, Canada", Journal of Regional Science, 34(3), pages 361 to 385, table 3 (data sample is monthly sales by Ontario municipal utility in 1989,elasticity of -0.0 to -0.07); and S.E. Henson (1984), "Electricity Demand Estimates under Increasing-Block Rates", Southern Economic Journal, 51(1), pages 147 to 156, table 11 (BPA; data sample is monthly data for 1077 households observed during 1977-78, elasticity is -0.11 to -0.28).

[30] BPA is a U.S. agency based in the Pacific Northwest which markets wholesale electricity from 31 U.S. federal hydro projects in the Columbia River Basin, one non-federal nuclear plant and several other small non-federal power plants.

- The four non-residential studies[31] E3 viewed as most comparable to B.C. report estimates of between zero and -0.142.

E3 stated at the 2008 LTAP proceeding that the double counting issue stems from the fact that long-run price elasticity studies do not generate a pure long-run price elasticity effect. E3's view was that these studies cannot pick up all the individual utility DSM programs that happen and all the government enacted codes and standards, and while the studies are called long-run price elasticity studies, there is a comingling of codes and standards, DSM programs and long-term pricing..

BC Hydro also reviewed IRPs put out by electric utilities in the Pacific Northwest to determine, among other things, which if any such utilities set out price elasticities and whether such elasticities are in line with those adopted by BC Hydro. Avista Corp. used an elasticity estimate of -0.15 for residential customers and -0.1 for non-residential customers in its 2011 IRP[32].

In addition, in August and September 2013 BC Hydro examined the -0.1 price elasticity in the context of a review of its RIB Evaluation Report. Price elasticity was estimated with econometric models that explain how electricity consumption per account might have changed in response to the RIB, after controlling for other potential drivers of consumption, including weather, region, and DSM spending. Unlike other price elasticity estimates in the literature, the price elasticity estimates

[31] G. Angevine and D. Hrytzak-Lieffers (2007), Ontario Industrial Electricity Demand Responsiveness to Price, Fraser Institute, page 10 (data sample is hourly load data from 47 Ontario companies from May 2002 to August 2006, elasticity of -0.102 to -0.142 for on-peak hours); E3 (1997), Consumption response to optimal real time pricing, 04/07/97 memo to BC Hydro (B.C.; data sample is daily consumption data by time of use for nine customers during the period 04/01/94 to 01/31/97, elasticity of -0.041 for heavy load hours and -0.083 for light load hours); J. Ham et al. (1997), "Time-of-Use Prices and Elasticity Demand: Allowing for Selection Bias in Experimental Data", RAND Journal of Economics, 28(0), pages 113 to 141, table 5 (Ontario; data sample is 15-minute load data for 120 small customers in a time-of-use experiment from 1985 to 1987, elasticity of -0.04 to -0.09); and J.P. Acton and R.E. Park (1987), Response to Time-of-Day Elasticity Rates by Large Business Customers: Reconciling Conflicting Evidence, Rand Report R-3477-NSF, table 16 (California, Wisconsin, Illinois and New York; data sample is monthly data by time-of-use for large customers served by 10 utilities in the U.S. during 1977-1980, elasticity is -0.00 to -0.025).

[32] Avista August 31, 2011 IRP, page 2 to 8; available at www.avistautilities.com/inside/resources/irp/electric/Documents/2011%Electric%20IRP.pdf. Avista is a public utility serving electricity customers in most of urban and suburban areas of 24 counties of eastern Washington State and northern Idaho.

derived from this analysis are incremental to non-rate related DSM activities, such as codes and standards. As a result, use of these estimates does not result in double-counting of the effects of DSM activities. The weather and region normalization also prevents under- or over-estimation of price elasticity due to idiosyncrasies in regional climate conditions and building practices. Three different econometric models estimated a range of the RIB Step-2 price elasticity between -0.08 to -0.13. This estimated range encompasses the Step-2 elasticity assumption for the RIB of -0.1 for forecasting RIB impacts.

3.4 Supply-Side Generation Resource Options Summary

There is the potential in B.C. for many types of supply-side resource options to be developed. As illustrated in Table 3-7, BC Hydro has EPAs with a number of generation resources of different types such as hydro, natural-gas, wind, biomass and biogas.

Table 3-7 Supply-Side IPP Projects in B.C.[33]

	In Operation		**Under Development**	
Project Type	**EPAs**	**Contracted Energy (GWh/year)**	**EPAs**	**Contracted Energy (GWh/year)**
Biogas	5	82	1	8
Biomass	10	2,354	10	1,479
Energy Recovery Generation (Waste Heat)	3	140	0	0
Natural Gas-Fired	2	3,140	0	0
Municipal Solid Waste	1	131	1	745
Non-Storage Hydro	45	3,470	32	4,429
Storage Hydro	10	4,760	3	365
Wind	3	997	5	1,185
Total	**79**	**15,074**	**52**	**8,211**

This section presents an overview of the supply-side generation resource options. The identified resource option potential is minimally screened[34] in this chapter and

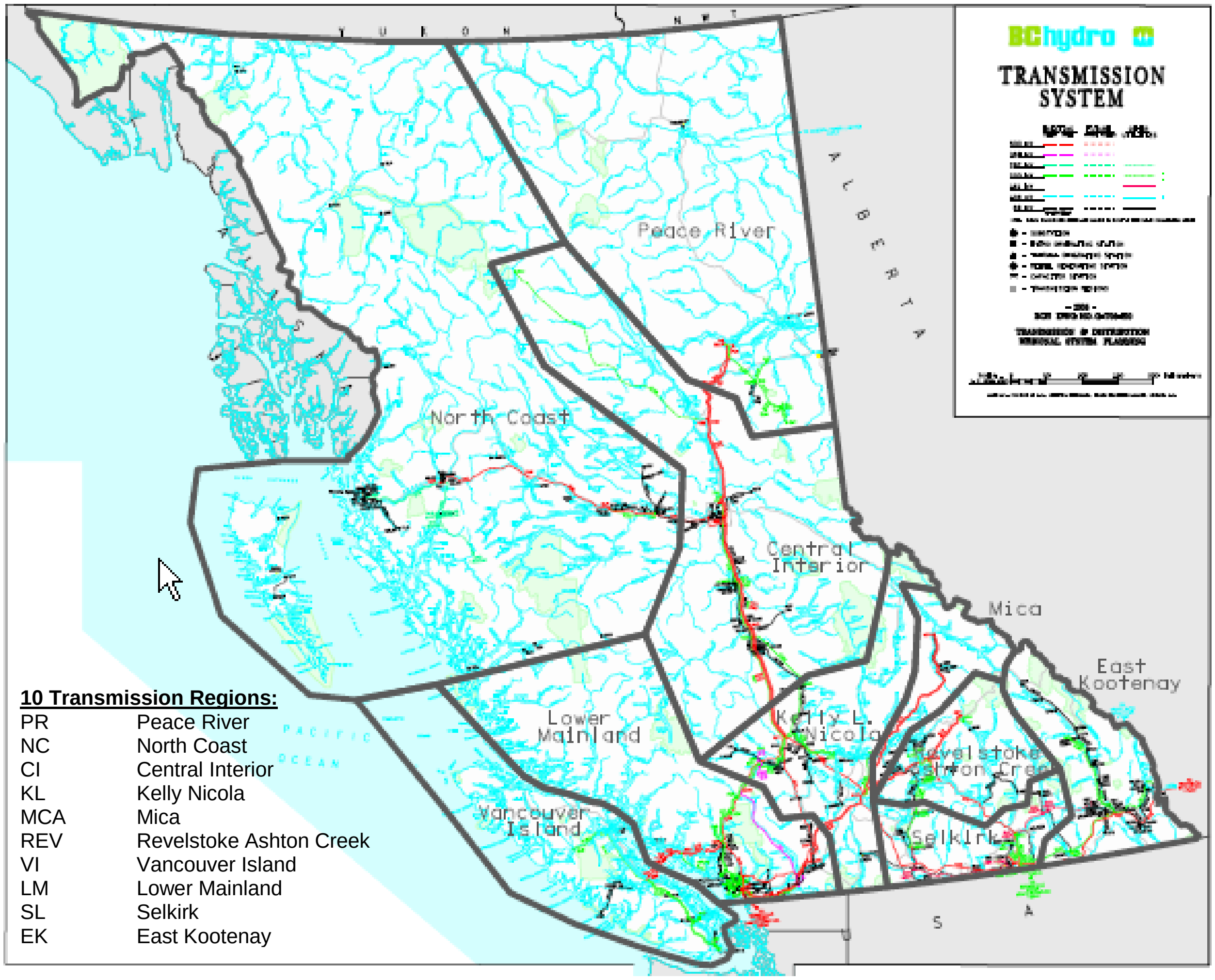
[33] As of April 1, 2013.

therefore results in a large volume of potential energy with a wide range of costs, which may or may not be developed in the future. Additional information on BC Hydro's investigations into emerging supply-side resource options is presented in section 3.6. Chapter 4 sets out the second screening process which is used to determine if a resource is viable or not.

The remainder of this section is organized according to energy and capacity resource options, presented in section 3.4.1 and 3.4.2 respectively. Technical and financial results are presented for each resource option where UECs and UCCs are shown at POI. In addition, resource option data are reported by transmission region where the interconnection occurs. Figure 3-6 below shows a map of the 10 transmission regions used in the 2013 ROR Update. Section 3.4.3 provides summaries of energy and capacity resource potential and costs, with the presentation of adjusted UECs to account for the costs described in section 3.2.2.

[34] Some base level screening was conducted to remove sites from consideration if they were located in an area where there would be legal or regulatory prohibitions e.g., projects located in legally protected areas (per B.C. Government's 2010 designation) or situated on a salmon-bearing stream.

Figure 3-6 BC Hydro's Transmission Planning Regions



3.4.1 Energy Resource Options

3.4.1.1 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 pine beetle-killed wood)
- Roadside wood waste (wood already harvested, but left in the forest or road side, some are pine beetle-killed wood)
- Sawmill wood waste

For the 2010 ROR, BC Hydro engaged a team of 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. For the 2013 ROR Update, BC Hydro engaged Industrial Forest Services Ltd. for an update to the 2010 modeling study following the same modeling methodology. The updated study found that the overall amount of standing timber available for fuel was forecast to decline significantly over the next 15 years, but then stabilize by 2025. 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.

A summary of the technical and financial results for wood-based biomass is presented in Table 3-8. BC Hydro has undertaken two wood-based biomass power acquisition processes in the form of a Request for Proposals (**RFP**), with the following results:

- Bioenergy Phase 1 Call RFP (2008/2009) which resulted in four EPAs for a total of 579 GWh/year of firm energy. The average levelized plant gate price for firm energy was $111/MWh ($F2013).
- Bioenergy Phase 2 Call RFP (2010/2011) which resulted in four EPAs for a total of 754 GWh/year of firm energy. The average levelized plant gate price for firm energy was $123/MWh ($F2013).

To date, BC Hydro bioenergy EPAs have typically had terms of between 10 to 15 years. 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 can be dispatchable but dispatchability depends on the ability of the proponent to interrupt fuel supply or stockpile while not impacting the debt obligations or investment returns of the plant.

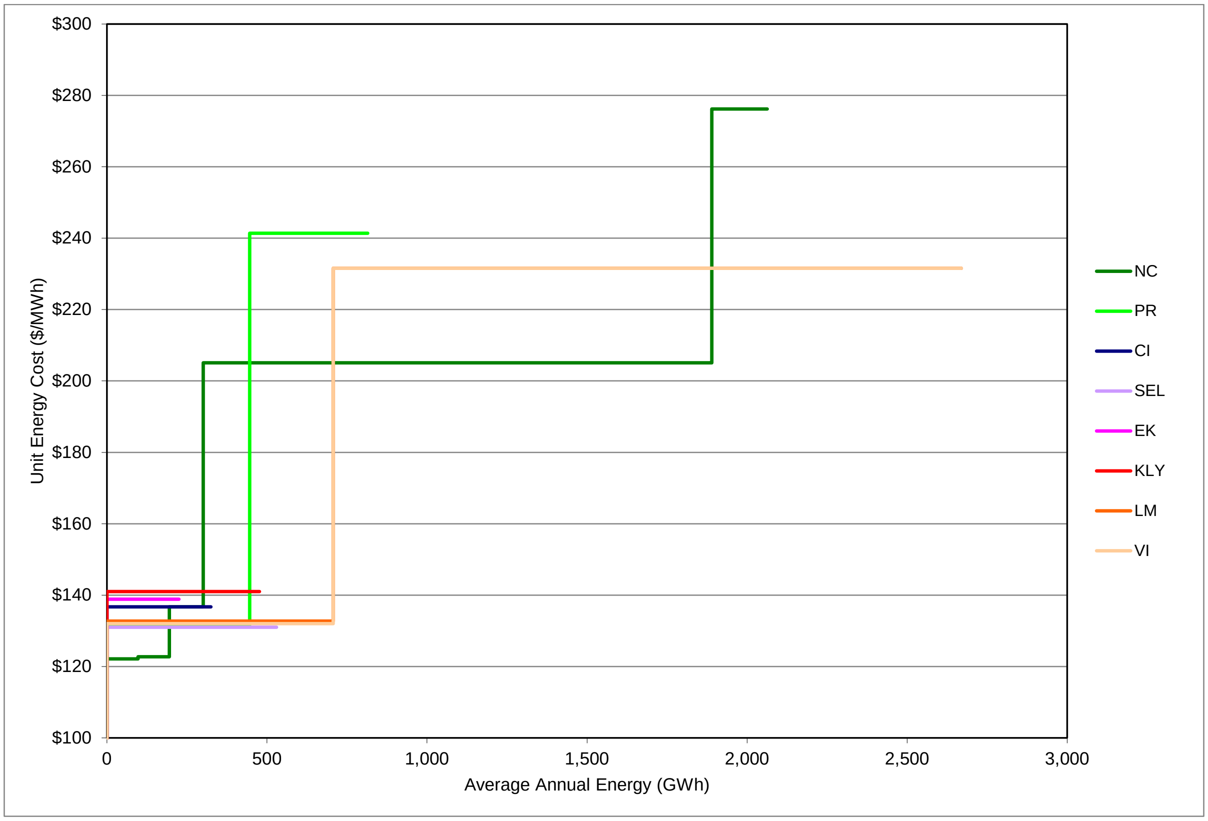
Table 3-8 Summary of Wood-Based Biomass Potential

Transmission Region	Number of Potential Sites[1]	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Standing Timber						
Peace River	1	46	46	368	368	241
North Coast	2	221	221	1,762	1,762	205 – 276
Vancouver Island	1	246	246	1,962	1,962	232
Lower Mainland	1	246	246	1,962	1,962	232
Sub-Total	5	759	759	6,054	6,054	205 – 276
Roadside Debris & Wood Waste						
Peace River	1	56	56	446	446	132
North Coast	3	38	38	301	301	122 – 137
Central Interior	1	41	41	325	325	137
Kelly Nicola	1	60	60	476	476	141
Vancouver Island	1	89	89	707	707	132
Lower Mainland	1	89	89	707	707	133
Selkirk	1	66	66	530	530	131
East Kootenay	1	28	28	225	225	139
Sub-Total	10	467	467	3,718	3,718	122 – 141
Total	**15**	**1,226**	**1,226**	**9,772**	**9,772**	**122 – 276**

1. 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. The boundary of forestry sub-regions and transmission regions do not align; as such, there can be more than one fibre delivery location within a given transmission region.

The supply curves for the wood-based biomass resource potential based on POI costs, by transmission region, are shown in Figure 3-7.

Figure 3-7 Wood-Based Biomass Supply Curves



3.4.1.2 Biomass – Biogas or Landfill Gas

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

In developing the landfill gas resource potential, BC Hydro reviewed a report by Golder Associates.[35] A summary of the technical and financial results for biogas is presented in Table 3-9. Although a viable resource, landfill gas is not included in the Chapter 6 portfolio analysis due to its small potential. The impact of the small

[35] "Inventory of Greenhouse Gas Generation from Landfills in British Columbia", by Golder Associates, 2008.

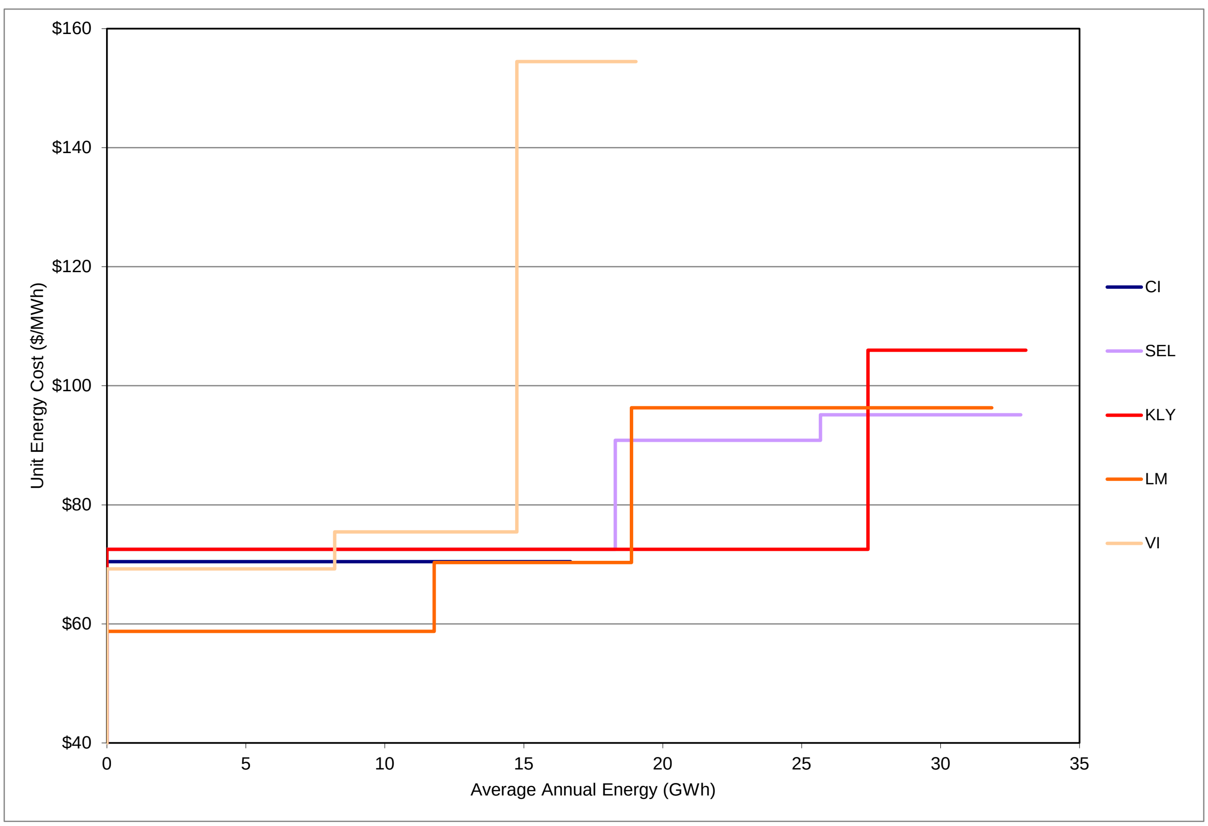
1 volume of energy and capacity from landfill gas potential on portfolio results would
2 be insignificant and would not impact the conclusions derived from the analysis.

3 **Table 3-9 Summary of Biogas Potential**

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Central Interior	1	2	2	17	17	70
Kelly Nicola	2	4	4	33	33	73 – 106
Vancouver Island	3	2	2	19	19	69 – 154
Lower Mainland	3	4	4	32	32	59 – 96
Selkirk	3	4	4	33	33	73 – 95
Total	**12**	**17**	**16**	**134**	**134**	**59 – 154**

4 The supply curves for biogas resource potential based on POI costs, by
5 transmission region, are shown in Figure 3-8.

6 **Figure 3-8 Biogas Supply Curves**



3.4.1.3 Biomass – Municipal Solid Waste

MSW biomass refers to the conversion of municipal solid waste into a usable form of energy, such as electricity. Conventional combustion and gasification are the most commonly used MSW technologies. The MSW resource option potential is estimated based on fuel source availability, whereby 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.

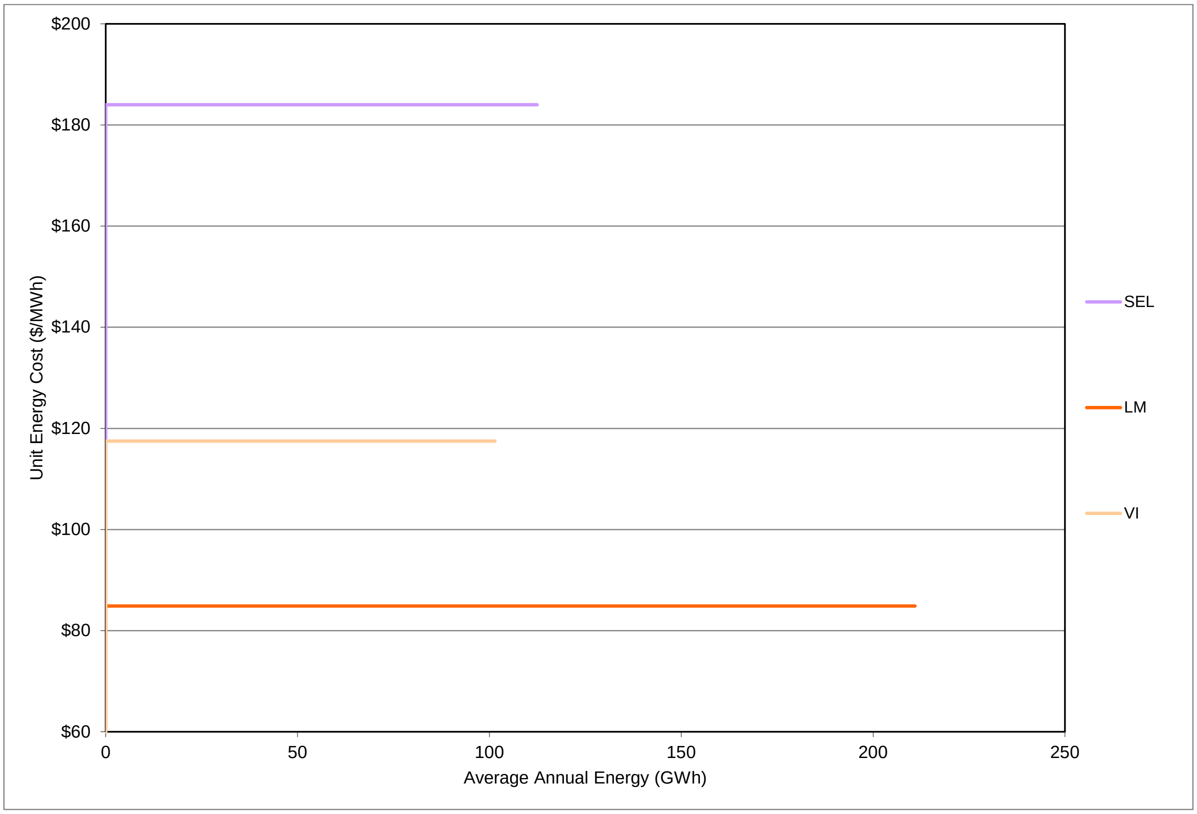
A summary of the technical and financial results for MSW is contained in Table 3-10.

Table 3-10 Summary of MSW Biomass Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Vancouver Island	1	12	12	101	101	117
Lower Mainland	1	25	25	211	211	85
Selkirk	1	14	13	112	112	184
Total	**3**	**51**	**50**	**425**	**425**	**85 – 184**

The supply curves for MSW resource potential based on POI costs, by transmission region, are shown in Figure 3-9.

Figure 3-9 MSW Biomass Supply Curves



3.4.1.4 Onshore Wind

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

For the 2010 ROR, BC Hydro engaged DNV Global Energy Concepts Inc. to complete the Wind Data Study (April 2009) and Wind Data Study Update (September 2009) to obtain detailed information on the wind resource potential in B.C., and engaged a consultant, Garrad Hassan to provide onshore wind cost assumptions (November 2010). For the 2013 ROR, the onshore wind resource potential and costs were updated to reflect the most recent trends in turbine efficiencies and pricing. This has resulted in lower wind costs in comparison to the 2010 ROR wind costs.

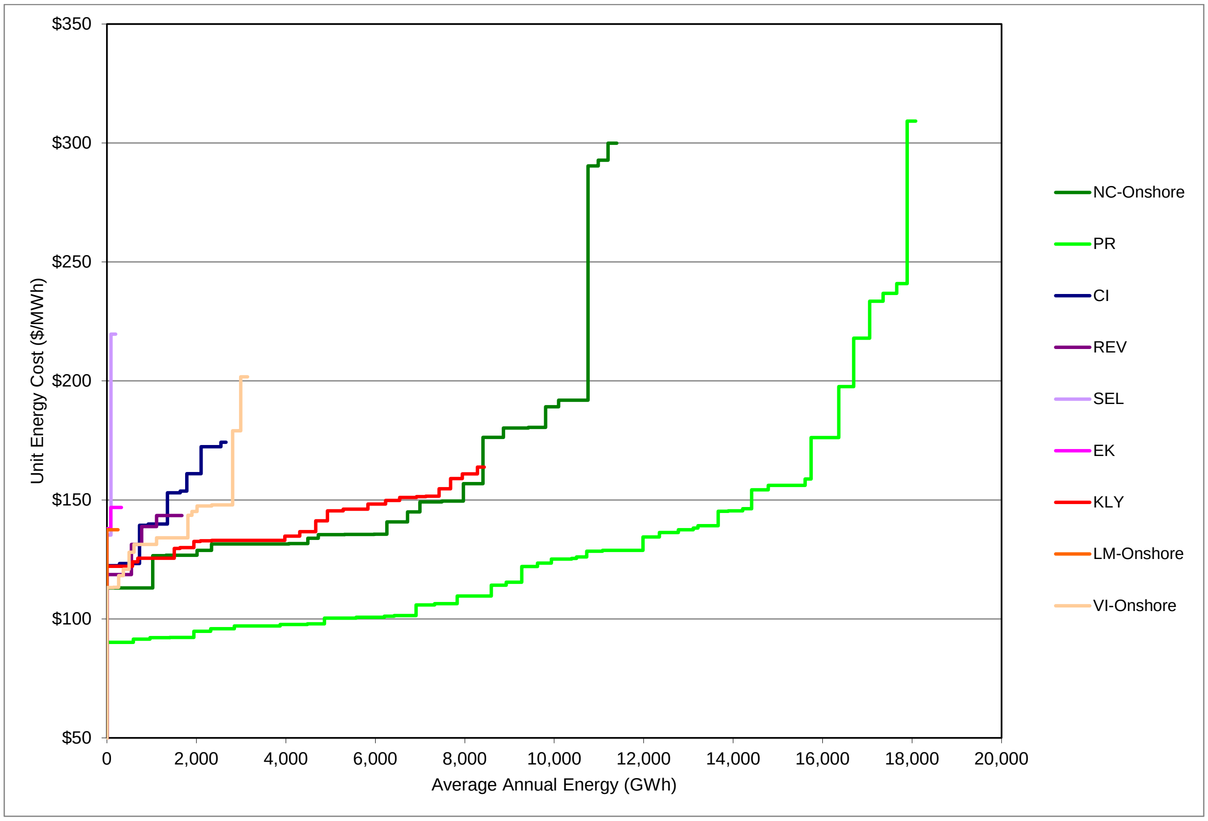
A summary of the technical and financial results for onshore wind is contained in Table 3-11. For comparison purposes, the average levelized plant gate cost for firm energy of the EPAs awarded for wind projects as part of BC Hydro's Clean Power Call is $108/MWh ($F2013). To date, BC Hydro wind EPAs have typically had terms of between 20 to 25 years.

Table 3-11 Summary of Onshore Wind Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Peace River	45	5,864	1,525	18,083	18,083	90 – 309
North Coast	23	4,085	1,062	11,400	11,400	113 – 300
Central Interior	9	1,049	273	2,660	2,660	122 – 174
Kelly Nicola	22	3,363	874	8,437	8,437	122 – 164
Revelstoke	4	644	167	1,674	1,674	119 – 143
Vancouver Island	13	1,111	289	3,143	3,143	113 – 202
Lower Mainland	1	90	23	249	249	137
Selkirk	2	83	22	194	194	135 – 220
East Kootenay	2	138	36	324	324	138 – 147
Total	**121**	**16,425**	**4,271**	**46,165**	**46,165**	**90 – 309**

The supply curves for onshore wind resource potential based on POI costs, by transmission region, are shown in Figure 3-10.

1 **Figure 3-10 Onshore Wind Supply Curves**



2 Onshore wind power generation is subject to natural variations in wind speed and
3 the amount of electricity generated is difficult to forecast. Wind power generation is
4 highly variable on time scales of seconds to minutes, requiring the electric system to
5 have additional highly-responsive capacity reserves to maintain system reliability
6 and security. The natural variability in wind power generation also makes it difficult to
7 predict wind in the hour- to day-ahead time frame, resulting in the need to set aside
8 system flexibility in order to address variations in wind power generation. These
9 requirements for system reserves and flexibility have cost implications that are
10 specific to wind power generation[36], and hence are captured through a wind
11 integration cost adjustment.

[36] Other renewable resources, such as solar and wave, are also highly variable in the short-term timescales. However, because they are not expected to participate or be selected in future acquisition processes in a significant manner, their integration costs have not been specifically estimated. The variability of run-of-river generation is largely contained within the monthly/seasonal time frame, which is captured in the IRP modeling tools.

BC Hydro first introduced the wind integration cost in the 2008 LTAP. Based on a preliminary analysis, a wind integration cost of $10/MWh was applied in the 2008 LTAP portfolio selection. In 2010, BC Hydro concluded a more detailed wind integration study, which is described in Appendix 3E. This study showed wind integration costs ranging from $5/MWh to $19/MWh, depending on the load year studied, geographic diversity level and wind penetration level. Given that the previous $10/MWh adjuster is within the cost range, BC Hydro is maintaining this figure as the wind integration cost in the IRP analysis. This value will be updated over time with further experience and data availability.

The $10/MWh wind integration cost is not reflected in the UEC values set out in Table 3-11, but has been included in Table 3-26 in section 3.4.3, and in the portfolio analysis described in Chapter 6.

3.4.1.5 Offshore Wind

In addition to onshore wind potential, BC Hydro also examined the potential of offshore wind turbines located in ocean substrate depths of up to 40 metres. 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.

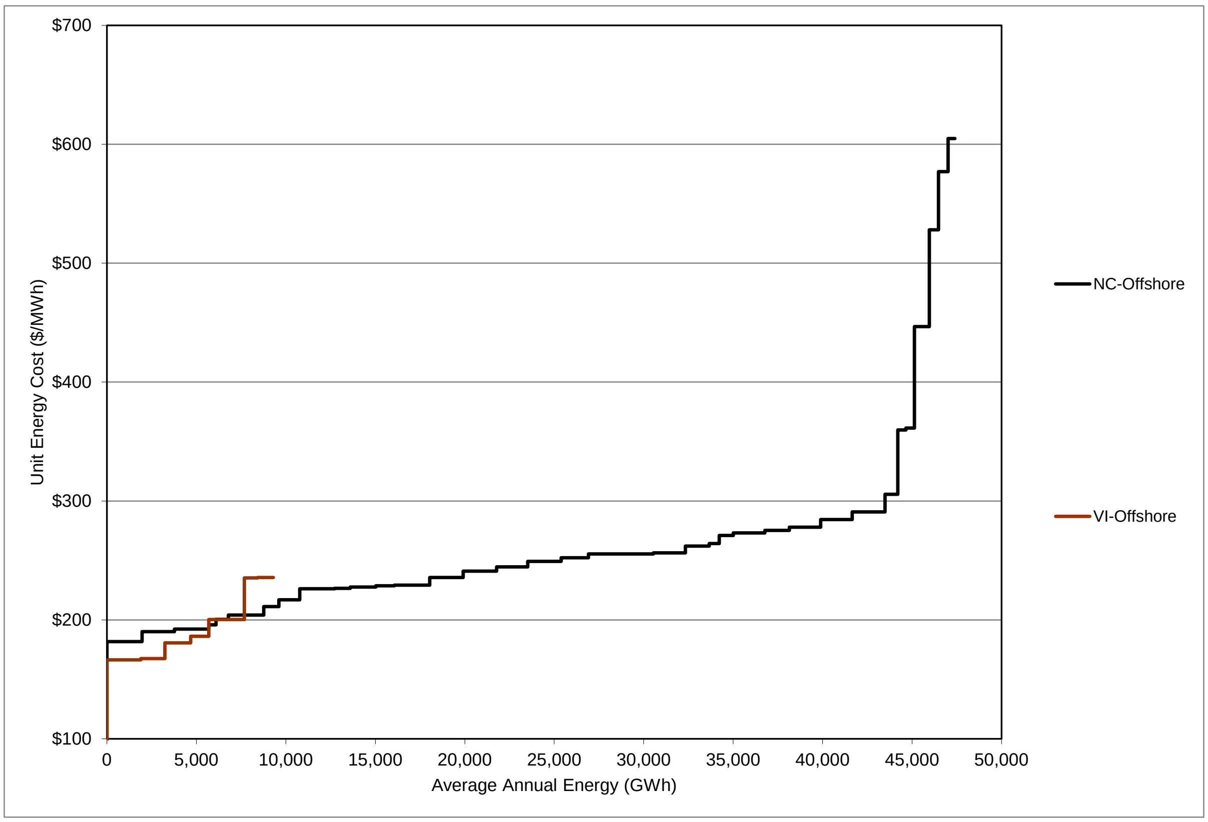
The analysis is based on averaged wind speeds at 80 metre hub height from the Canadian Wind Atlas and gridded bathymetric data provided by the Canadian Hydrological Services. Modelled wind speeds from the Canadian Wind Atlas were compared to long-term wind speed estimates based on actual offshore observations. 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 3-12. Similar to the onshore wind, offshore wind will incur a $10/MWh wind integration cost as well, which is not reflected in this table, but has been included in Table 3-26 in section 3.4.3, and in the portfolio analysis described in Chapter 6.

Table 3-12 Summary of Offshore Wind Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
North Coast	36	12,319	3,203	47,397	47,397	182 – 605
Vancouver Island	7	2,369	616	9,303	9,303	166 – 236
Total	**43**	**14,688**	**3,819**	**56,700**	**56,700**	**166 – 605**

The supply curves for offshore wind resource potential based on POI costs, by transmission region, are shown in Figure 3-11.

Figure 3-11 Offshore Wind Supply Curves



3.4.1.6 Run-of-River Hydroelectricity

A run-of-river hydro generation facility diverts a portion of natural stream flows and uses the natural drop in elevation of a river to generate electricity. A weir (i.e., a structure smaller than a dam used for storage hydro) is required to divert flows into the penstocks that lead to the power generation facilities. A run-of-river project either has no storage, or a limited amount of storage, in which case the storage reservoir is referred to as pondage.

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. In general, seasonal river flows are high during the late spring/early summer freshet period (May to July), which coincides with reduced demand and low electricity prices in external markets, and seasonal river flows are lower and less predictable in the winter when demand and prices for electricity are the highest. Generation drops during low flow periods.

The freshet issue is addressed through a firm energy adjustment whereby the amount of firm energy for each resource option during the freshet period is limited to 25 per cent of the total firm energy for the year. This adjustment is made in Table 3-26 as part of the adjusted UEC discussion in section 3.4.3 but not to Table 3-13.

The 2010 ROR (which was subsequently revised in 2013) for run-of-river resources was completed in collaboration with Kerr Wood Leidal Associates Ltd. The study used a Geographical Information System (**GIS**) 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 the run-of-river resource option is contained in Table 3-13.

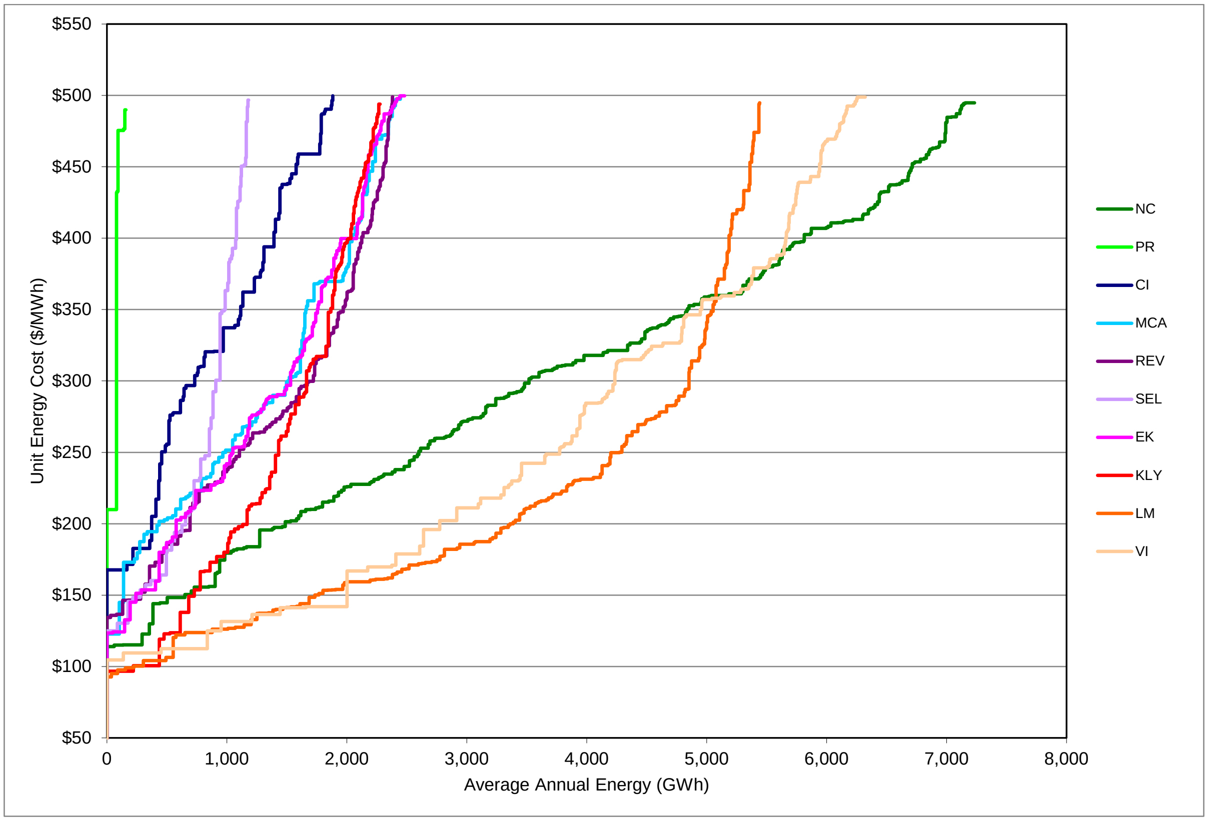
Table 3-13 Summary of Run-of-River Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Peace River	6	55	2	158	88	210 – 490
North Coast	260	2027	226	7232	5786	114 – 495
Central Interior	62	616	43	1950	1597	168 – 500
Kelly Nicola	101	783	31	2277	1809	97 – 494
Mica	101	786	32	2452	1928	123 – 499
Revelstoke	123	828	32	2383	1648	134 – 499
Vancouver Island	163	1754	420	6322	4802	105 – 499
Lower Mainland	173	1551	310	5443	4189	93 – 495
Selkirk	44	405	13	1182	835	125 – 497
East Kootenay	136	773	41	2481	1861	124 – 500
Total	**1,169**	**9,579**	**1,149**	**31,880**	**24,543**	**93 – 500**

Note: The table presents results for run-of-river resources under $500/MWh.

The supply curves for run-of-river resource potential based on POI costs, by transmission region, are shown in Figure 3-12.

Figure 3-12 Run-of-River Supply Curves



Note: This figure presents results for run-of-river resources under $500/MWh.

3.4.1.7 Large Hydro – Site C

Site C is a proposed third dam and hydroelectric generating station on the Peace River in northeastern B.C. Site C would be located downstream from the existing Williston Reservoir and the two existing BC Hydro generating facilities (GMS and Peace Canyon). It would include an earthfill dam, approximately 1,050 m in length, and 60 m high above the river bed. The reservoir would be 83 km long and would be, on average, two to three times the width of the current river. It would have relatively little fluctuation in water levels, with a proposed maximum normal operating range of 1.8 m.

Site C would provide approximately 1,100 MW of dependable capacity and produce more than 4,700 GWh/year of firm energy (5,100 GWh/year of average energy). As the third dam and generating station on the Peace River, Site C would gain significant efficiencies by taking advantage of water already stored in the upstream

Williston Reservoir to generate electricity. As a result, Site C would generate about 35 per cent of the electricity produced at the W.A.C. Bennett Dam, with only five percent of the reservoir area. Site C would be a publicly-owned Heritage asset, with a significant upfront capital cost, low operating costs and a long life of more than 100 years. Site C is a dispatchable resource.

The data in this chapter is based on the information provided in the Site C EIS submission filed with the EAO and the Agency in January 2013 and the Evidentiary Update submitted to the Site C Joint Review Panel in September 2013. Table 3-14 summarizes the technical and financial characteristics of Site C.

Table 3-14 Site C Summary

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Peace River	1	1,100	1,100	5,100	4,700	83

Note: Based on capital cost of $7.9 billion as per updated cost estimate provided in the Site C EIS submission filed in January 2013. The UEC is presented using a 5 per cent discount rate and includes sunk costs. For portfolio analysis, sunk costs to March 31, 2013 are removed, which reduces the UEC to $76/MWh in $2011.

3.4.1.8 Geothermal

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

Geothermal electricity can be produced based on conventional or unconventional resources. Conventional resources are in the form of steam or, much more commonly, hot water; while unconventional resources are found in rock that is hot but essentially dry, and commonly called hot dry rock resources. 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.

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 3-15. Cost parameters were assigned based on a high-level review of published costs for new geothermal projects globally, and adjusted to account for the challenging geographical conditions of B.C. sites and the higher risk of failed wells for B.C. greenfield sites relative to expansion projects of well-understood geothermal reservoirs. Even with this adjustment, given the high risks and challenges associated with the three stages of the development of geothermal resources – confirmation, drilling or feasibility, and construction – the estimates shown are likely to be low.

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 described in Chapter 6 for the following reasons:

- Historically, resource options identified through the ROR high-level screening process and that have the lowest unadjusted UEC values have not always been the projects that are developed and bid into BC Hydro's power acquisition processes. Despite its relatively low cost (an unadjusted UEC of $91/MWh in $F2013), geothermal resource developers have never bid into BC Hydro's power acquisition processes. From the 2010 ROR, 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 and Mines 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 Power Corp. (now Ram Power, Corp.) in 2004 at South Meager Creek; however, the multi-million dollar drilling program failed to yield geothermal wells useful for geothermal power production.

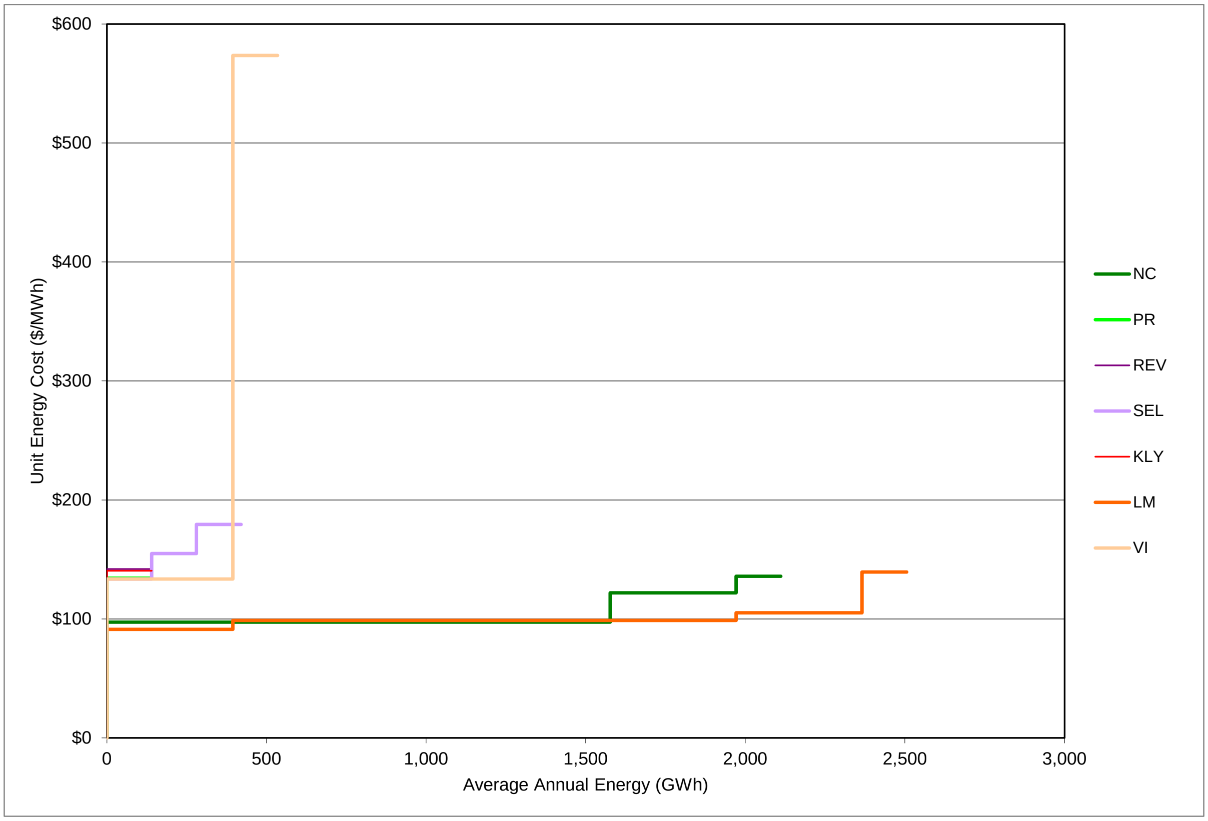
Table 3-15 Summary of Geothermal Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Peace River	1	20	20	140	140	134
North Coast	3	270	270	2,111	2,111	97 – 136
Kelly Nicola	1	20	20	140	140	141
Revelstoke	1	20	20	140	140	142
Vancouver Island	2	70	70	534	534	134 – 573
Lower Mainland	5	320	320	2,505	2,505	91 – 139
Selkirk	3	60	60	420	420	134 – 179
Total	**16**	**780**	**780**	**5,992**	**5,992**	**91 – 573**

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

The supply curves for geothermal resource potential based on POI costs, by transmission region, are shown in Figure 3-13.

Figure 3-13 Geothermal Supply Curves



3.4.1.9 Natural Gas-Fired Generation

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

- Combined cycle gas turbines or CCGTs are an energy and capacity resource. CCGTs use the combination of combustion and steam turbines to generate electricity. Exhaust gases from a combustion turbine flow to a heat recovery steam generator that produces steam to power a steam turbine, resulting in higher efficiencies than those achievable by operating the combustion or steam turbines individually. CCGTs have a relatively high efficiency in converting fuel to electricity in comparison to other thermal generation. Conversion efficiencies are typically about 55 per cent to 60 per cent for CCGTs.
- Simple cycle gas turbines or SCGTs are a capacity resource. SCGTs are stand-alone generating plants that use combustion gases to propel a turbine,

similar to a jet engine connected to an electrical generator. SCGTs are less efficient than CCGTs in converting fuel to electricity. Conversion efficiencies are typically about 35 to 40 per cent for SCGTs. SCGTs are discussed in section 3.4.2.2 because they are a capacity resource.

- Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power generation and a low pressure steam/thermal 'host' to use the excess 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 can be as high as 80 per cent depending on the nature of the steam host.

Natural gas-fired generation is dispatchable and provides firm energy and dependable capacity.

Clean Energy Act Considerations

Section 2 of the *CEA* sets out two of the B.C. energy objectives which are relevant to the role of natural gas-fired generation:

- The first objective is found in subsection 2(c) and provides: "to generate at least 93 per cent of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship, from clean or renewable resources…" The definition of "clean or renewable resources" in section 1 of the *CEA* does not include natural gas-fired generation.
- The second objective is contained in subsection 2(g) of the *CEA,* setting out the B.C. Government's legislated GHG emission reduction targets

CEA Clean or Renewable Resource Target

BC Hydro currently has five natural gas-fired generating facilities in its system:

- Burrard Thermal Generating Station (**Burrard**)

- Fort Nelson Generating Station
- Prince Rupert Generating Station
- Island Generation Plant (IPP owned)
- McMahon Cogeneration Plant (IPP owned)

No energy is assumed from Burrard for planning purposes as a result of subsections 3(5) and 6(2)(b) of the *CEA*. 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. The four other gas-fired facilities contribute 3,520 GWh/year of firm energy to the system, and account for more than 5 of the 7 allowance for natural gas-fired generation under the 93 per cent clean or renewable target. Thus, little space is left for developing new natural gas-fired generation.

Table 3-16 sets out the maximum GWh of new natural gas-fired generation that could be built by around F2024, assuming the 2012 Load Forecast after DSM and without LNG load. Table 3-16 also shows the number of MWs of new natural gas-fired generation that could be built by around F2024.

Table 3-16 Determination of Permissible Natural Gas-Fired Generation

Year	F2024
Space available for natural gas-fired generation (7 per cent of total generation energy requirements used as a proxy for generation)	4,430 GWh
Energy contribution from existing natural gas-fired generation	3,520 GWh
Permissible volume of new natural gas-fired generation that could be built	910 GWh
Associated capacity of new natural gas-fired generation (CCGT) (90 per cent capacity factor)	115 MW
Associated capacity of new natural gas-fired generation (SCGT) (18 per cent capacity factor)	577 MW

GHG Offset Requirement

Subsection 2(g) of the *CEA* sets out the B.C. Government's legislated GHG emission reduction targets. BC Hydro has not factored GHG costs into the UEC values set out in Table 3-17; however, a GHG cost of $30 per tonne of CO_2e has been factored into the section 3.4.3 adjusted UECs and the portfolio analysis described in Chapter 6. Refer also to section 5.4.2.2.

BC Hydro undertook an in-house update of the cost and performance characteristics of three representative CCGT units located in the Kelly Lake/Nicola area of B.C. – a 50 MW unit, a 250 MW unit and a 500 MW unit. BC Hydro also prepared an in-house update for potential cogeneration units in the Lower Mainland. A summary of the technical and financial results for the natural gas-fired generation resource options is contained in Table 3-17.

Table 3-17 Summary of CCGT and Small Cogeneration Potential

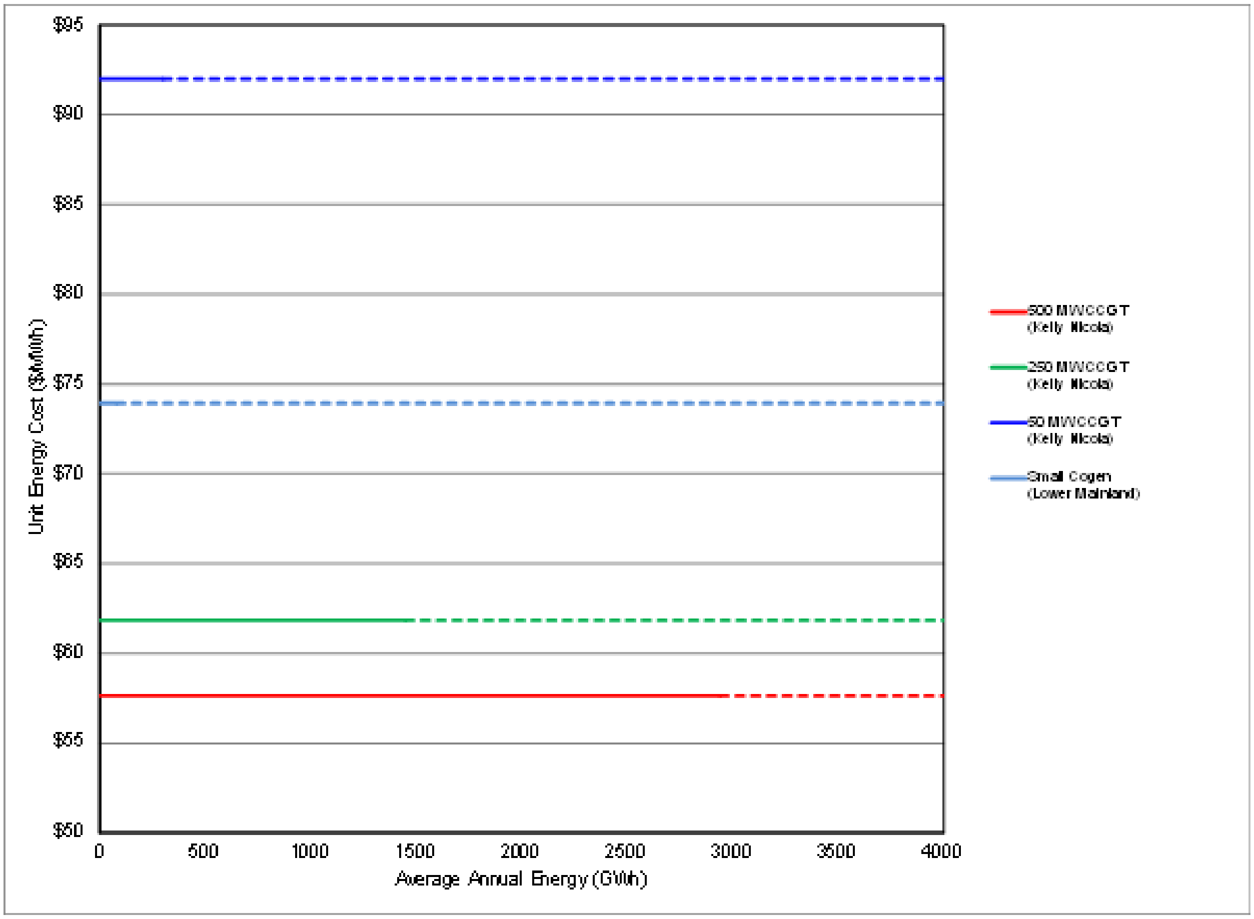
Resource Option	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
50 MW CCGT in Kelly Lake/Nicola	1	56	49	300	386	92
250 MW CCGT in Kelly Lake/Nicola	1	263	236	1,450	1,861	62
500 MW CCGT in Kelly Lake/Nicola	1	530	479	2,940	3,776	58
Small Cogeneration in Lower Mainland	1	10	10	80	80	74

Notes:

1. Representative project used to characterize the resource option.
2. UECs are based on natural gas price estimates from BC Hydro's 2013 Market Scenario 1, and do not include the cost of GHG offsets or the B.C. carbon tax.
3. Additional gas price scenarios and their likelihoods are provided in Chapter 5. The impact of these prices is addressed in the portfolio analysis described in Chapter 6.

The supply curves for the CCGT and small cogeneration resource options, based on POI costs, are shown in Figure 3-14.

Figure 3-14 CCGT and Small Cogeneration Supply Curves



Note: The solid line indicates the energy contribution of a single representative project. A dotted line indicates additional potential.

3.4.1.10 Coal-Fired Generation with CCS

Policy Action No. 20 of the 2007 BC 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. According to the Electric

Power Research Institute,[37] coal-fired generation plants with 90 per cent carbon dioxide emission capture and storage would not be commercially available until about 2028; this was also the conclusion of Powertech Labs Inc.[38] There is uncertainty with respect to the CCS, and with respect to what impact CCS 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 sequestration, 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 CCS 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.

In developing the potential of coal-fired generation with CCS resource option, BC Hydro relied upon reports prepared by Powertech Labs Inc. in 2009 and a 2007 National Energy Technology Laboratory report.[39] A summary of the technical and financial results for the coal-fired generation with CCS resource option is contained in Table 3-18.

Table 3-18 Summary of Coal-Fired Generation with CCS Potential

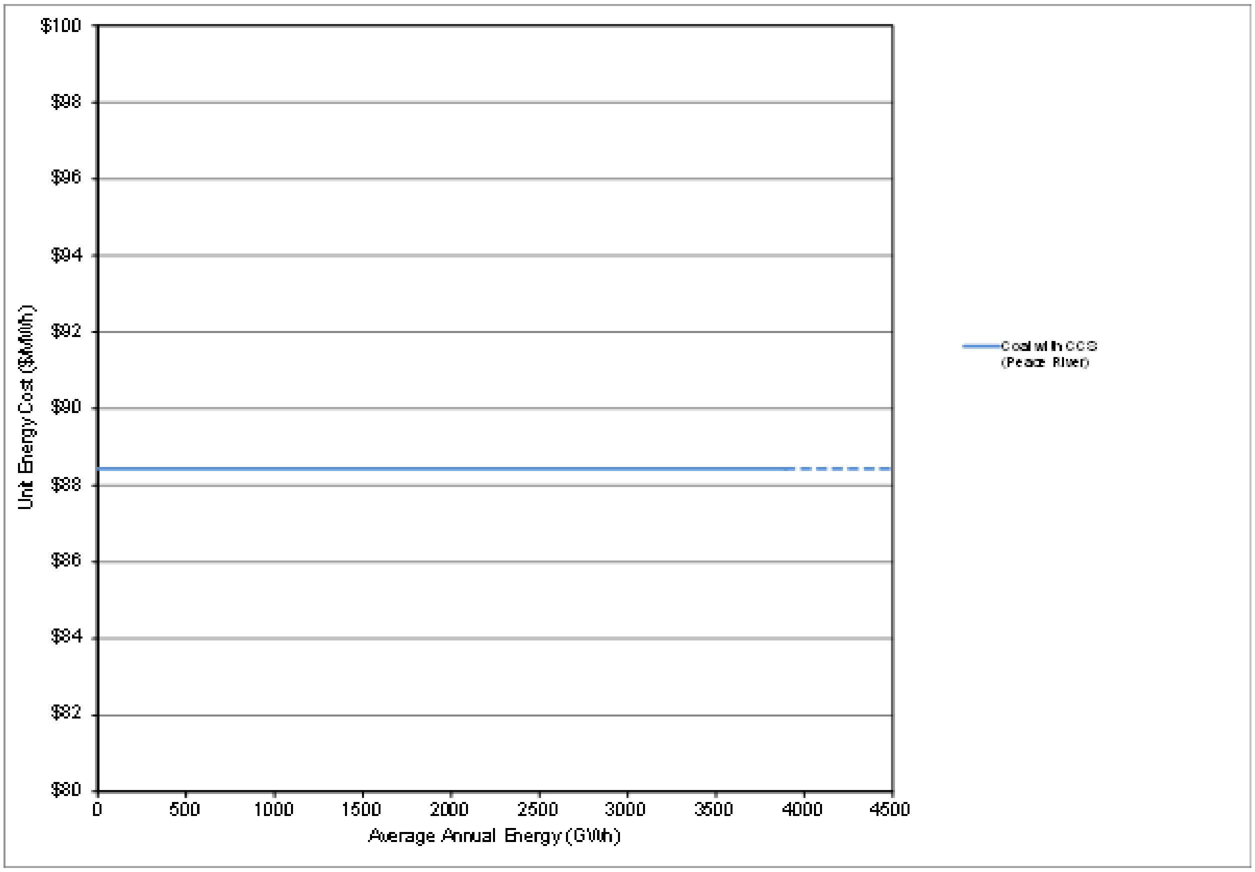
Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
Peace River	1	745	556	3,896	3,896	88

Note:
1. Representative project used to characterize the resource option.
2. The dependable capacity was discounted to account for the energy used up by the CCS process.
3. Coal-fired generation with CCS is an emerging technology. There is significant uncertainty around the cost estimates provided.

The supply curve for the coal-fired generation with CCS resource option, based on POI costs, is shown in Figure 3-15.

[37] EPRI Journal, "Pathways to Sustainable Power in Carbon-Constrained Future", Fall 2007, page 4-13.
[38] Powertech Labs Inc. 2009.
[39] "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report", Revision 1, August 2007.

Figure 3-15 Coal-Fired Generation with CCS Supply Curve



Note: The solid line indicates the energy contribution of a single representative project. A dotted line indicates additional potential.

3.4.1.11 Wave

Wave energy is generated by winds blowing over the surface of the ocean. Because ocean waves are a product of the interactions among variable local winds, occasional storms and the effects of distant sea conditions, wave energy is a complex and variable phenomenon. Currently, there are five approaches to capturing the wave energy resource, all of which are at the early stages of commercial development and with potential application in B.C. There are currently no wave energy projects in B.C. waters, although two demonstration projects have received support from provincial and federal innovative clean energy funding agencies.

BC Hydro relied on information in the GIS map of the Integrated Land Management Bureau tenure database, and the incoming wave power for the site from the Canadian Hydraulic Centre[40] report 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.[41] A summary of the technical and financial results for the wave resource option is contained in Table 3-19.

Table 3-19 Summary of Wave Potential

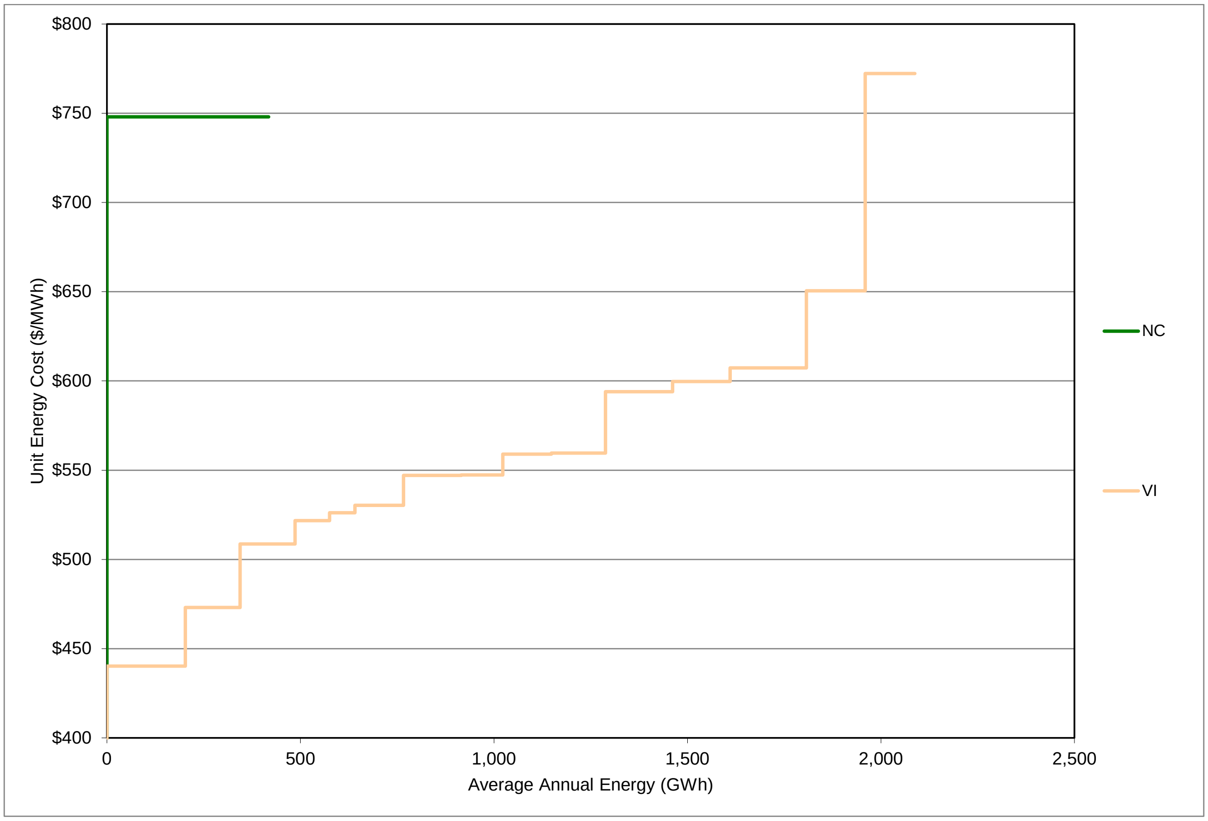
Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
North Coast	1	143	34	418	418	748
Vancouver Island	15	936	225	2,088	2,088	440 – 772
Total	**16**	**1,078**	**259**	**2,506**	**2,506**	**440 – 772**

The supply curves for the wave resource potential, based on POI costs, are shown in Figure 3-16.

40 Canadian Hydraulic Centre, Inventory of Canada's Marine Renewable Energy Resources, April 2006.

41 Future Marine Energy, Results of the Marine Energy Challenge: Cost Competitiveness and Growth of Wave and Tidal Stream Energy, Carbon Trust, January 2006.

Figure 3-16 Wave Supply Curves



3.4.1.12 Tidal

Tidal energy refers to the kinetic energy available in the flow of water driven by the rotation of the Earth in the gravitational fields of the sun and the moon. Tidal energy 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 viable prospect in B.C. This assessment focuses exclusively 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 referenced above in respect of wave resource to assess the costs of tidal development.

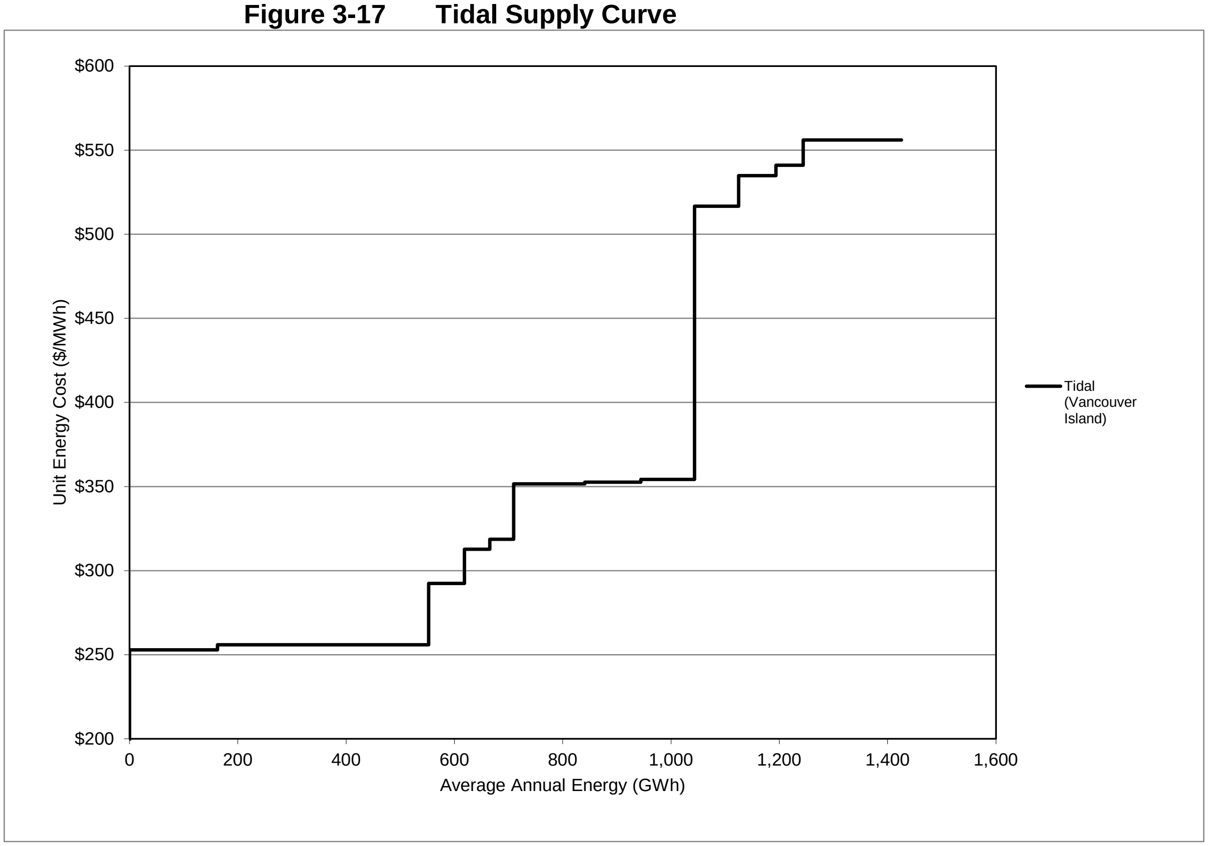
A summary of the technical and financial results for the tidal resource option is contained in Table 3-20.

Table 3-20 Summary of Tidal Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Vancouver Island	12	617	247	1,426	1,426	253 – 556
Total	**12**	**617**	**247**	**1,426**	**1,426**	**253 – 556**

The supply curve for the tidal resource option, based on POI costs, is shown in Figure 3-17.

Figure 3-17 Tidal Supply Curve



3.4.1.13 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 (**CSP**) technologies. Both the photovoltaic and CSP technologies are commercially proven. Globally costs for solar technologies have declined dramatically. While this trend is expected to continue, costs are not expected to become competitive in Canadian jurisdictions over the next 10 years in the absence of price support. There are no known commercial solar power installations in British Columbia. However, several BC Hydro customers have installed small solar panels.

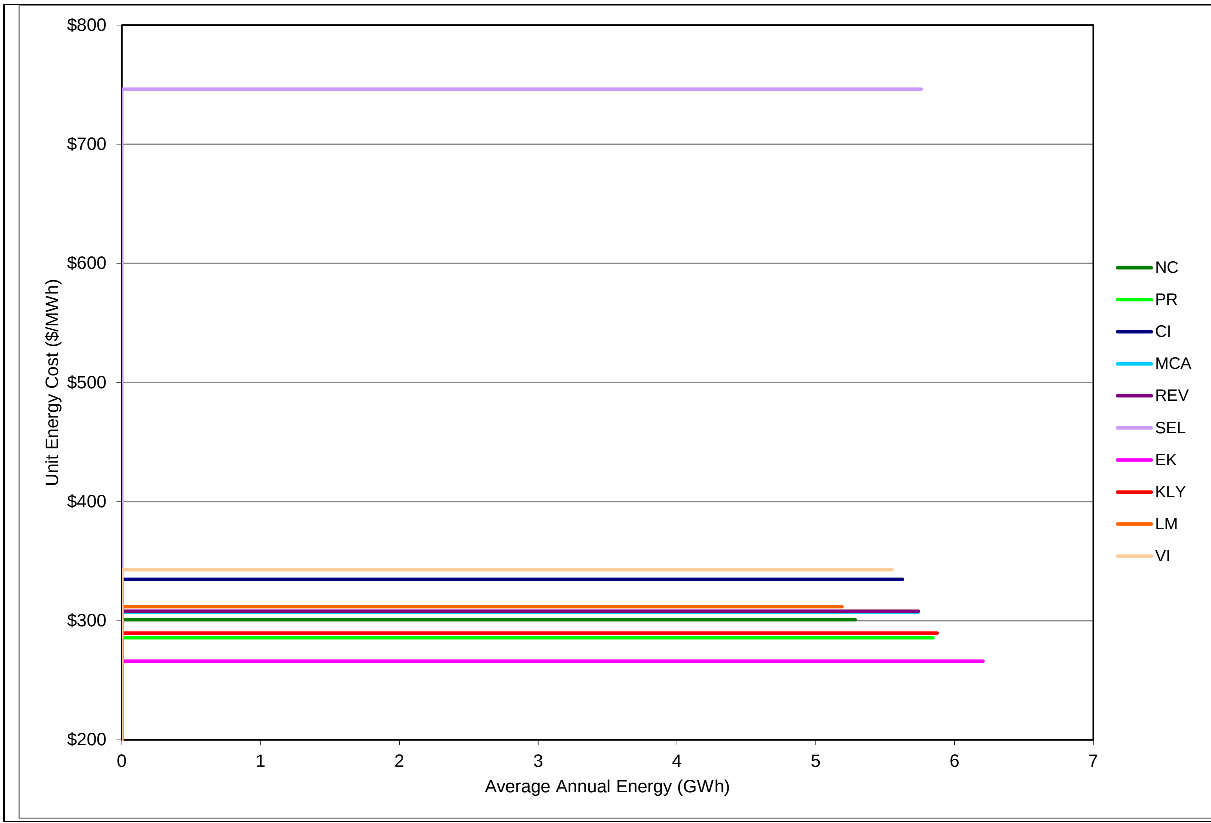
The solar resource option assessment focuses on utility-scale photovoltaic systems, which have the ability to modularly increase the size of the solar power installation size over time and thereby managing capital investment risk. CSP technologies are not included in this assessment due to the large upfront capital investment required for a utility scale implementation. The solar resource option 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 option is contained in Table 3-21.

Table 3-21 Summary of Solar Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
Peace River	1	5	1	6	6	286
North Coast	1	5	1	5	5	301
Central Interior	1	5	1	6	6	335
Kelly Nicola	1	5	1	6	6	290
Mica	1	5	1	6	6	307
Revelstoke	1	5	1	6	6	308
Vancouver Island	1	5	1	6	6	343
Lower Mainland	1	5	1	5	5	312
Selkirk	1	5	1	6	6	746
East Kootenay	1	5	1	6	6	266
Total	**10**	**50**	**12**	**57**	**57**	**266 – 746**

The supply curves for the solar resource potential based on POI costs, by transmission region, are shown in Figure 3-18.

Figure 3-18 Solar Supply Curves



3.4.1.14 Nuclear

Nuclear has not been investigated as a resource option given that Policy Action No. 23 of the 2007 BC Energy Plan provides that the B.C. Government “rejects nuclear power as a strategy to meet British Columbia’s energy needs”. This is reiterated in subsection 2(o) of the *CEA*, which specifies that B.C.’s energy objectives must be achieved without the use of nuclear power.

3.4.2 Capacity Resource Options

3.4.2.1 Pumped Storage

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

The ability to store water and release it during times of system need makes PS a potentially useful capacity resource. PS units can respond quickly to variations in system demand and can provide ancillary services such as voltage regulation. PS is the most widespread energy storage system in use on power networks with over 100,000 MW installed worldwide. However, there are no commercial PS facilities in British Columbia.

BC Hydro engaged Knight Piésold Ltd. to identify greenfield PS potential in the Lower Mainland, Vancouver Island and North Coast regions, and engaged Hatch Ltd. to assess the cost of installing a pump-turbine or a pump at Mica Generating Station. It should be noted that the Mica pumped storage option is unique in that it has seasonal shaping capability whereas other options only have daily shaping capability. Seasonal shaping capability allows the use of low-cost freshet energy for pumping in order to save the energy for higher value months. This capability can also enhance BC Hydro’s ability to manage the freshet oversupply issue as discussed in section 6.4. A summary of the technical and financial results for the PS resource option is contained in Table 3-22. As PS is considered a capacity option, only the UCCs are shown.

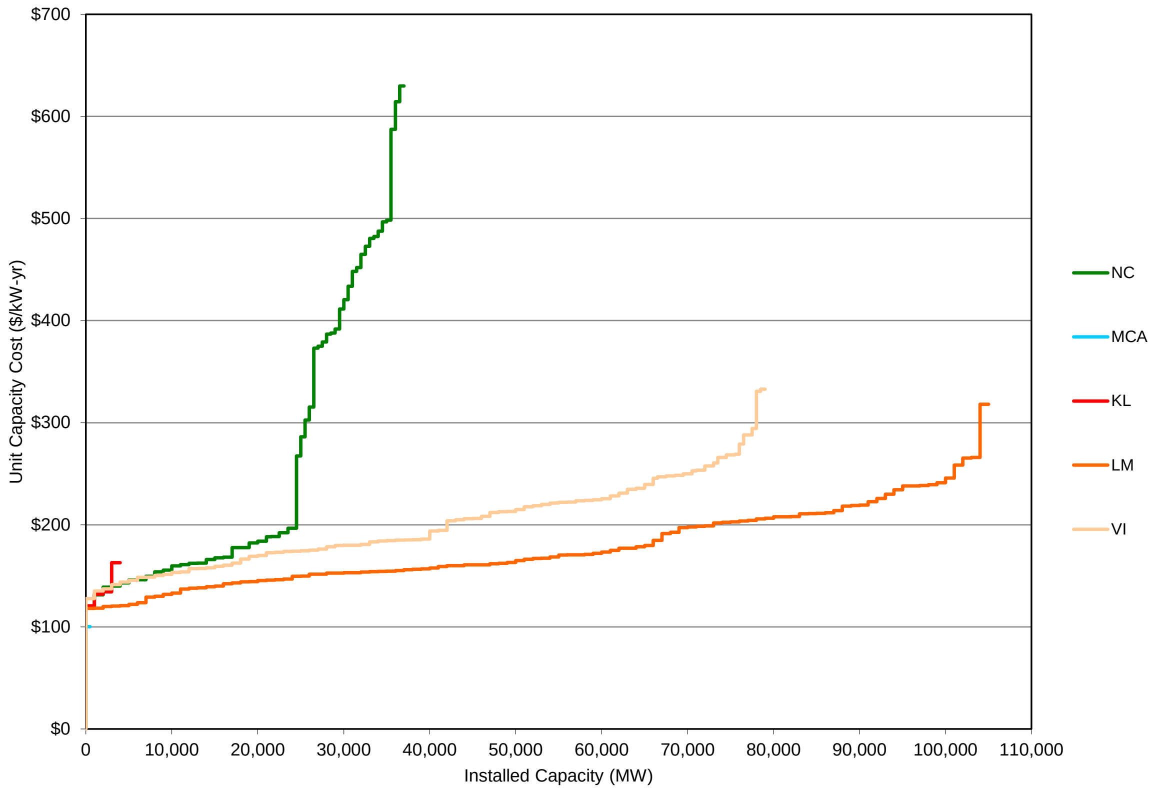
Table 3-22 Summary of Pumped Storage Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	UCC at POI ($2013/kW·year)
Kelly Nicola	4	4,000	4,000	121 – 163
Mica	1	500	465	100
Vancouver Island	84	79,000	79,000	128 – 333
Lower Mainland	105	105,000	105,000	118 – 318
North Coast	50	37,000	37,000	119 – 630
Total	**244**	**225,500**	**225,465**	**100 – 630**

Notes:
UCCs for pumped storage include fixed costs only.
Mica Pumped Storage UCC is calculated at a 5 per cent real discount rate.
North Coast UCCs are at plant gate; transmission and road access cost components are not included.

The supply curves for PS potential in the transmission regions investigated, based on POI costs, are shown in Figure 3-19.

Figure 3-19 Pumped Storage Supply Curves



3.4.2.2 Natural Gas-Fired Generation – SCGT

Gas-fired units generate electricity using the heat released by the combustion of natural gas. SCGTs are the most common gas-fired units used as capacity resources. Conversion efficiencies are typically 35 to 40 per cent for SCGTs. Refer to section 3.4.1.9 regarding the application of the *CEA* 93 per cent clean or renewable target to natural gas-fired generation, including SCGTs. 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.

BC Hydro undertook an in-house update of the cost and performance characteristics of two representative natural gas-fired units: a 100 MW SCGT unit in Kelly

Lake/Nicola area and a 100 MW SCGT unit on Vancouver Island. The UCCs for the two representative SCGTs are shown in Table 3-23.

Table 3-23 Summary of the SCGT Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	UCC at POI ($2013/kW·year)
100 MW SCGT in Kelly Lake/Nicola	1	103	98	84
100 MW SCGT on Vancouver Island	1	103	101	180

Note: UCCs for SCGTs include fixed costs only.

3.4.2.3 Resource Smart

There is some opportunity to modestly increase the energy and/or capacity within BC Hydro's existing fleet of 30 hydroelectric Heritage assets. These opportunities are commonly referred to as Resource Smart opportunities.

Energy and/or capacity increases can be realized as stand-alone investments planned specifically to satisfy an energy and/or capacity need identified through the long-range planning process, or the opportunities can be realized at the time of reliability refurbishment or replacement investments associated with the major generating components. The capability of all of the major generating components (generator, turbine, unit transformer, circuit breaker, exciter, governor, water passage) and auxiliary equipment have to be able to facilitate the increased energy and capacity requirements so in some cases it can take a long time to fully realize the uprated potential of the Heritage assets if combined with reliability improvements.

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 in section 2.3) are:

- The addition of one unit (500 MW) at Revelstoke Generating Station in the B.C. Interior (Revelstoke Unit 5, in operation in F2011)

- The addition of two units (approximately 500 MWs each) at Mica Generating Station in the B.C. Interior (Mica Units 5 and 6 are expected to be in-service in F2015 and F2016, respectively).
- Increasing the capacity of Units 6 to 8 at the GMS Generating Station on the Peace River, providing additional capacity of approximately 90 MW (in-service in F2013)
- Replacing the runners at Ruskin Generating Station in the Lower Mainland, adding approximately 9 MW of additional capacity and 28 GWh/year of energy
- Replacement of the G1 and G2 generator stators at the Cheakamus Generating Station in the Lower Mainland and increasing the dependable capacity of each unit by approximately 20 MW each with an expected in-service date of September 2017 for Unit 1 and March 2018 for Unit 2
- The identification phase of a generator stator reliability improvement capital project is underway with potential to add approximately 4 MW to each of Units 5 and 6 at the Bridge River Generating Station
- The identification phase of a capital project to explore the feasibility, impacts, and energy capability associated with the dredging of Grohmann Narrows in the Kootenay region

There is also an opportunity to redevelop the Alouette Generating Station which has been included for about 50 GWh/year and 7 MW of dependable generating capacity in the load-resource balance in Chapter 2. The Alouette facility has been forced out of service since February 2010 but could be uprated to as much as 22 MW. Four possible redevelopment scenarios have been identified; however, BC Hydro has not made a final decision at this time.

Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase

The largest remaining Resource Smart projects identified in terms of additional dependable capacity are Revelstoke Unit 6 with a dependable capacity of 488 MW and GMS Units 1-5 Capacity Increase with a dependable capacity of up to 220 MW. A summary of the technical and financial results for these two Resource Smart options is contained in Table 3-24.

Table 3-24 Summary of Resource Smart Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UCC at POI ($2013/kW-year)
Peace River (GMS Units 1-5)	1	220	220	Not available; likely to be small	Not available; likely to be small	35
Revelstoke	1	500	488	26	26	50

Note: GMS Units 1-5 Capacity Increase numbers are based on conceptual level estimates. The installed capacity and DGC will be in the range of 185 MW to 220 MW.

Other Resource Smart Potential Opportunities

There are other opportunities to install stand-alone, small generating units at existing generating facilities to add capacity and/or energy during reliability improvement projects as summarized in Table 3-25. These projects are at a preliminary state of investigation. The high-level estimates indicate that the UCCs associated with these opportunities are higher than the ones BC Hydro is currently pursuing, and therefore, they are not pursued strictly for filling the capacity gap. The most economic opportunities to pursue are likely those associated with planned reliability improvement projects as the costs of the increased capacity and/or energy output are generally incrementally small relative to the cost of the underlying reliability project but there are many additional factors to consider that may affect the feasibility of these opportunities. Examples include regulatory and environmental impacts, First Nations and stakeholder impacts, and transmission interconnection costs.

Table 3-25 Summary of Resource Smart Potential

Resource Smart Option	Energy (GWh/year)	UEC at POI ($/MWh, $F2013)	Capacity (MW)	UCC at POI ($/kW-year, $F2013)
Strathcona additional unit (Campbell River, Vancouver Island)	0	N/A	31	104
Ladore additional unit (Campbell River, Vancouver Island)	8	291	9	259
Ash River additional unit (Ash River, Vancouver Island)	30	88	9	293
Puntledge additional unit (Puntledge River, Vancouver Island)	18	72	10	132
Duncan Dam new generation (Duncan River/Columbia River area)	103	102	30	350
Lajoie additional unit (Bridge River/Fraser River area)	80	111	30	297
Replace runners at Seven Mile Generating Station (Pend-d'Oreille River, Interior)	26	356	32	290

3.4.2.4 Canadian Entitlement

The Canadian Entitlement is the Canadian portion of the potential for additional electricity produced in the Columbia River in the western U.S. as a result of the Columbia River Treaty ratified in 1964. The Province owns the Canadian Entitlement and Powerex markets the energy under an agreement with the Province. While the Province receives the financial benefits of the Canadian Entitlement, BC Hydro has access to the physical product (energy and capacity) and can use it as a source of limited supply. As this supply is not "solely from electricity facilities within the Province", given the self-sufficiency requirement in subsection 6(2) the *CEA*, the Canadian Entitlement is not a source of dependable capacity in the long term, and therefore, the role of the Canadian Entitlement is limited as a bridging or contingency resource option. Refer to section 9.2.7 for a discussion on how BC Hydro proposes to rely on the Canadian Entitlement as a bridging option.

3.4.3 Summary of Supply-Side Generation Resource Options

In section 3.4, the UECs of supply-side resources are shown based on POI. The UECs shown in this subsection are adjusted to reflect the cost of resources delivered to the Lower Mainland, which is BC Hydro's major load centre. The other adjustments include: GHG offset costs of $30 per tonne of CO_2e based on the B.C. carbon tax for natural gas-fired generation and coal with CCS; a wind integration cost of $10/MWh; a freshet firm energy adjustment whereby the amount of firm energy for each resource option during the freshet period (May to July) is limited to 25 per cent of the total firm energy for the year; and a capacity credit of $50/kW-year based on the cost of Revelstoke Unit 6 applied to resource option that can provide dependable capacity such as wood-based biomass, biogas, MSW, natural gas-fired generation, coal-fired generation with CCS, Site C, and geothermal resources. The results are summarized in Table 3-26 and Figure 3-20. Refer to Appendix 3A-34 for details concerning the adjusted UECs. It is worth noting that the firm energy adjustment is expected to lower Site C's adjusted UEC given its hourly to seasonal shaping capability (currently estimated at $2/MWh) but a conservative approach of zero adjustment has been assumed.

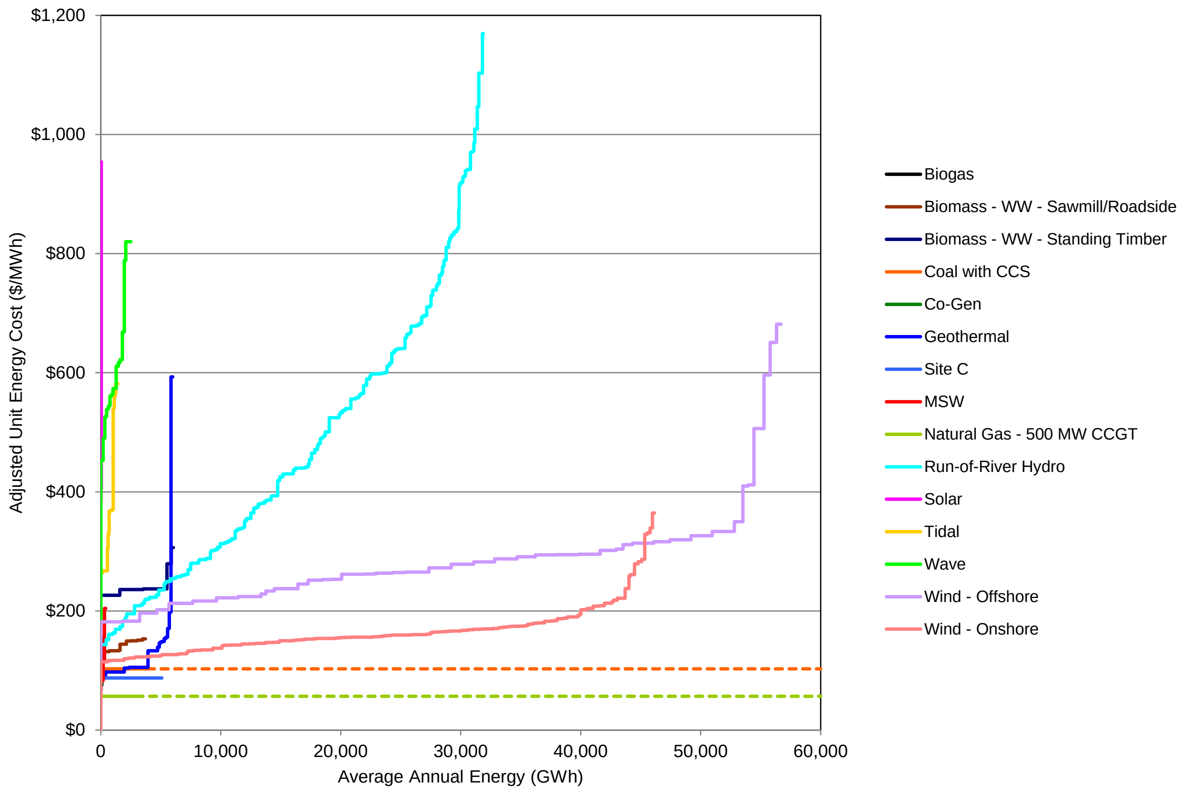
Table 3-26 Summary of Supply-Side Energy Resource Options[1]

Energy Resource	Total FELCC Energy (GWh/year)	Total DGC or ELCC Capacity (MW)	UEC at POI at 7% Real ($2013/MWh)	Adjusted Firm UEC[2] at 7% Real ($2013/MWh)
Biomass – Wood Based	9,772	1,226	122 – 276	132 – 306
Biomass – Biogas	134	16	59 – 154	56 – 156
Biomass – MSW	425	50	85 – 184	83 – 204
Wind – Onshore	46,165	4,271	90 – 309	115 – 365
Wind – Offshore	56,700	3,819	166 – 605	182 – 681
Geothermal	5,992	780	91 – 573	90 – 593
Run-of-River Hydro	24,543	1,149	97 – 493	143 – 1,170
Site C[3]	4,700	1,100	83	88
CCGT and Cogeneration[4]	6,103	774	58 – 92	57 – 86
Coal-fired Generation with CCS	3,896	556	88	103
Wave	2,506	259	440 – 772	453 – 820
Tidal	1,426	247	253 – 556	264 – 581
Solar	57	12	266 – 746	341 – 954

Notes:

1. The resource and UEC values shown for each category in the table reflect the resource potential analyzed and may not include all possible resources that may be available at higher estimated costs.
2. The details of how the cost adjusters were developed and applied are provided in Appendix 3A-34. The cost estimates as shown are results of survey-level assessments and should not be viewed as feasibility indicators of low-cost projects in future power acquisition processes.
3. The Site C values presented in this table are based on information provided in the Site C EIS submission filed in January 2013, and the UEC is a levelized value calculated using a 5 per cent real discount rate.
4. Representative projects were used to characterize the natural gas-fired and coal-fired generation with CCS options, and the resource potential is generally considered to be unlimited.

Figure 3-20 Energy Resource Option Supply Curves

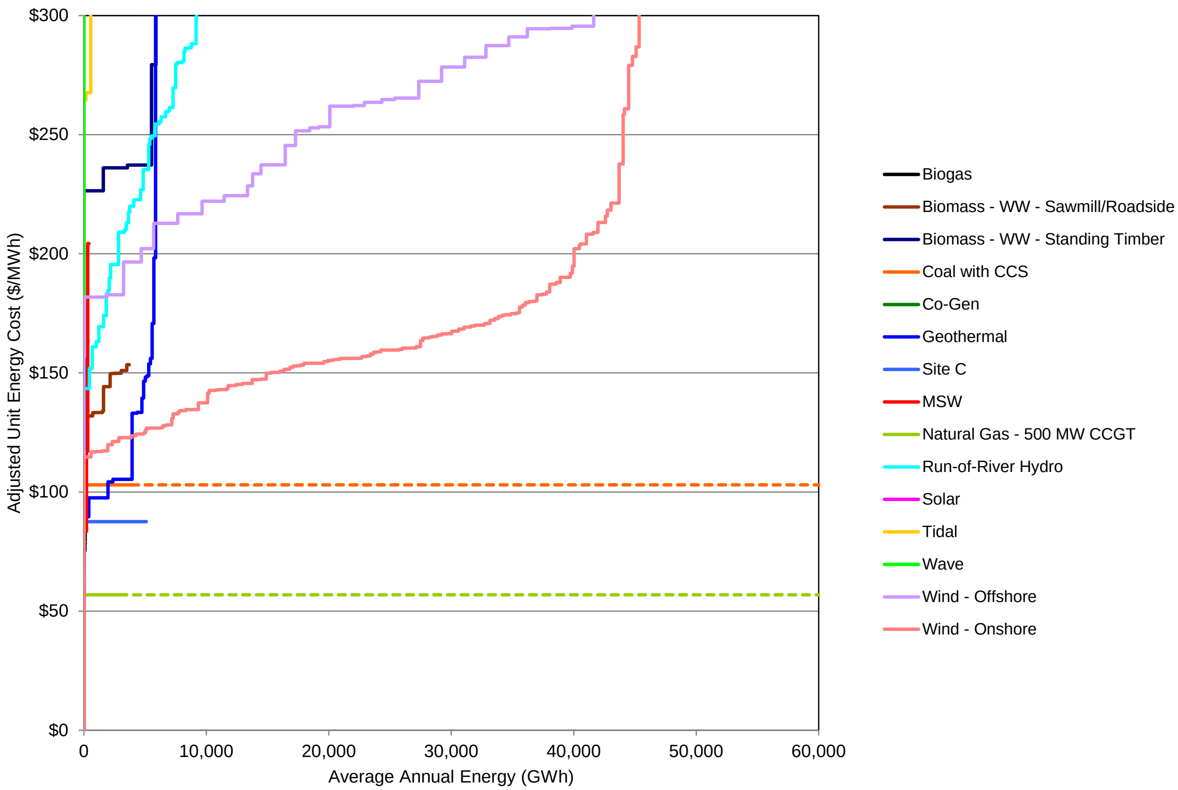


Notes:

1. The resources and UEC values shown for each category in the table reflect the resource potential analyzed and may not include all possible resources that may be available at higher estimated costs.
2. The Site C values presented in this table are based on information provided in the Site C EIS submission filed in January 2013, and the UEC is a levelized value calculated assuming a 5 per cent real discount rate.
3. Representative projects were used to characterize the natural gas-fired and coal-fired generation with CCS resource options. Dotted lines indicate additional potential, which is generally considered to be unlimited.

For ease of viewing, the lower left portion of Figure 3-20 with adjusted UECs less than $300/MWh is provided at a larger scale in Figure 3-21.

1 **Figure 3-21 Energy Resource Option Supply Curves with**
2 **Adjusted Firm UEC Less Than $300/MWh**



3 The UCCs of the supply-side capacity resource options are summarized in
4 Table 3-27.

Table 3-27 UCCs of Capacity Resource Supply Options

Resource Type	Capacity Options	Dependable Capacity (MW)	UCC at POI ($2013/kW-year)
Resource Smart	GMS Units 1-5 Capacity Increase	220	35
Resource Smart	Revelstoke Unit 6	488	50
Natural Gas-Fired Generation	SCGTs at two locations	98 or 101	84 or 180
Pumped Storage	PS at Mica Generating Station	465	100
Pumped Storage	PS at various locations	1,000	118 – 124

Notes:
1. Only fixed costs are included.
2. UCCs for GMS Units 1-5 Capacity Increase, Revelstoke Unit 6, and PS at Mica Generating Station are levelized values calculated assuming a 5 per cent real discount rate. All other projects assume a 7 per cent real discount rate.
3. Two SCGT representative projects are used to characterize the gas-fired generation resource option.
4. Presentation of PS data is limited to results below $125/kW-year.

There has been strong public interest to access the resource options information in GIS format. To meet the increasing requests, BC Hydro will post the 2013 Resource Options Update Geometric Locations & Associated Attribute information on BC Hydro's IRP website.

3.4.4 Electricity Purchase Agreement Renewals

The energy supply-side resource option attributes presented in section 3.4.1 are for new energy resources. BC Hydro may have access to energy from IPP projects already in operation through renewals of existing EPAs. As EPAs expire, BC Hydro intends to enter into negotiations for renewals of those EPAs that could provide the lowest cost, the greatest certainty of continued operation and best system support characteristics. BC Hydro's EPA renewal planning assumptions are described in section 4.2.5.1, and result in about 1,800 GWh/year of EPA renewal energy in F2021, rising to about 6,400 GWh/year in F2033 at the end of the IRP planning horizon.

3.5 Transmission Options Summary

To provide customers with electricity, BC Hydro must connect the generation resources to the electric system and deliver that electricity to customers through the transmission system. In addition, subsection 3(2) of the *CEA* requires that BC Hydro identify long-term transmission requirements in its IRP.

3.5.1 Bulk Transmission Options

To achieve the *CEA* mandate, BC Hydro reviewed the transmission options required to remove congestion from various sections of BC Hydro's bulk transmission network over a 30-year transmission resource planning horizon. A list of resource options for addressing congestion on the bulk transmission system is summarized in Table 3-28.

Table 3-28 Bulk Transmission Resource Options

Item No.	Upgrade Option Description	Lead Time (Years)	F2013 Direct Cost ($Million)	Incremental Capacity (MW)	Line Length (km)
	North Interior				
TO-01	New 500 kV, 50 per cent series compensated transmission circuit 5L8 between GMS and Williston Substation (**WSN**)	8	388.3	1470	278
TO-02	New 500 kV, 50 per cent series compensated transmission circuit 5L14 between WSN and Kelly Lake Substation (**KLY**)	8	341.1	2120	330
TO-03	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 1	8	1,482.9	1000	928
TO-04	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 2	8	246.8	1000	N/A
TO-05	Series compensation upgrade at Kennedy from 50 per cent to 65 per cent on GMS to WSN 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000A rating.	3	59.5	360 (CI-KLY/NIC) and 300 (PR-CI)	N/A

Item No.	Upgrade Option Description	Lead Time (Years)	F2013 Direct Cost ($Million)	Incremental Capacity (MW)	Line Length (km)
TO-06	Series compensation upgrade at McLeese capacitor station from 50 per cent to 65 per cent on WSN to KLY 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000A rating.	3	57.2	390 (CI-KLY/NIC) and 330 (PR-CI)	N/A
TO-07	500 kV Shunt compensation: WSN add one 300 MVAr static vAR compensators (**SVC**) and two 250 MVAr switchable capacitor banks. At KLY add one 250 MVAr shunt capacitor.	3	65.1	650 (CI-KLY/NIC) and 580 (PR-CI)	N/A
	North Coast				
TO-08	New 500 kV circuit Williston-Glenannan Substation (**GLN**)-Telkwa (**TKW**) Substation-Skeena Substation (**SKA**) parallel to the existing 5L61 - 5L62 and 5L63 lines.	8	1,031.6	970	449
TO-09	Series compensation of the WSN-SKA 500 kV lines 5L61, 5L62 and 5L63 plus voltage support and transformation addition in the existing BC Hydro substations	3	142.3	580	N/A
TO-21	A new +/-500 kV HVDC bipole transmission circuit between WSN and SKA	8	1,091.6	2000	449
	South Interior				
TO-10	New 500 kV, 50 per cent series compensated transmission circuit 5L97 between Selkirk Substation (**SEL**) and Vaseaux Lake Substation	8	226.7	750	163
TO-11	New 500 kV, 50 per cent series compensated transmission circuit 5L99 between Vaseaux Lake and Nicola Substation (**NIC**)	8	196.3	750	138
TO-12	50 per cent series compensation of the 500 kV lines 5L91 and 5L98	3	61.8	133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK)	N/A

Item No.	Upgrade Option Description	Lead Time (Years)	F2013 Direct Cost ($Million)	Incremental Capacity (MW)	Line Length (km)
TO-13	50 per cent series compensation of 500 kV lines 5L71 and 5L72	Committed in 2014	46.0	950	N/A
TO-14	50 per cent series compensation of 500 kV lines 5L76, 5L79, and 5L96	3	60.3	112	N/A
TO-19	50 per cent Series compensation of 500 kV line 5L92 SEL-Cranbrook Substation (**CBK**).	3	31.2	150	N/A
TO-20	A new 500 kV line between SEL and CBK parallel to the existing 500 kV line 5L92	8	651.1	1550	180
	Interior to Lower Mainland				
TO-15	New 500 kV, 50 per cent series compensated transmission circuit 5L83 between NIC and Meridian Substation (**MDN**)	Committed in 2015	609.2	1550	247
TO-16	New 500 kV, 50 per cent series compensated transmission circuit 5L46 between KLY and Cheekye Substation (**CKY**)	8	656.7	1384	197
TO-17	500 kV and 230 kV shunt compensation: At MDN 230 kV add two 110 MVAr capacitor banks; At NIC 500 kV add one 250 MVAr capacitor bank.	3	10.1	570	N/A
	Lower Mainland to Vancouver Island				
TO-18	New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal.	6	230.1	600	67

Note: TO-15 information is based on a progress report for the ILM project filed with BCUC in November 2011.

3.5.2 Transmission Expansion and Regional Transmission Projects

The main focus of the IRP process is to identify major bulk transmission upgrades and transmission facilities required for interconnecting new resources to the grid. However, some BC Hydro transmission projects are being advanced to alleviate regional transmission constraints or for transmission expansion purposes. These projects are captured in the discussion on regional planning issues and constraints identified in section 2.5 of the IRP.

3.5.3 Transmission for Export

As set out in subsection 3(1)(d) of the *CEA*, the IRP is required to provide a description of the expected export demand for electricity from incremental B.C. clean or renewable resources and the extent to which BC Hydro has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports. A discussion on export analysis is included in section 5.8. This section describes the transmission options considered for export purposes.

Existing transmission congestion along the Interstate 5 (I-5) corridor in the U.S. Pacific Northwest makes a new transmission path from the eastern part of B.C. to Mid-C and California more viable than other options. Therefore, Selkirk substation (**SEL**) is used as a modelling hub for collecting B.C.'s excess energy and transferring it to U.S. markets. For modelling purposes, a generic 500 kV single tower transmission path from SEL to Devil's Gap substation near Spokane in Washington State is considered as the new transmission link between B.C. and the U.S. Depending on the level of power transfer to the U.S., the SEL-to-Devil's Gap transmission path is configured with one or two 500 kV transmission circuit(s). The SEL-to-Devil's Gap circuit fits within the scope of a future hybrid transmission path from eastern B.C. to northern California.

This transmission path is also known as the Canada-Northwest-California (**CNC**) project. The CNC line could transfer up to 3,000 MW power from B.C.-based power facilities to Northern California and would include a double circuit 500 kV high-voltage alternating current line from SEL to Devil's Gap substation and to the North East Oregon (**NEO**) substation plus a +/- 500 kV HVDC bipole from NEO to the Collinsville substation near San Francisco. As described in section 5.8.4.2, the CNC partners have abandoned the CNC project for the foreseeable future.

3.6 Other Resource Options

In addition to the resource options potential identified in sections 3.3, 3.4 and 3.5, BC Hydro is doing further work to advance other resource options. The work ranges from monitoring the commercial readiness of technologies and/or assessments of resource potential to investigating market barriers to the development of certain resource options, investigating new materials to improve system performance, and identifying whether there is a role for BC Hydro to play in alleviating these barriers.

3.6.1 Distributed Generation

For the purposes of this work, BC Hydro defines distributed generation (**DG**) as:

> An approach whereby smaller-scale generation of electricity is located close to the load it is intended to serve and can be located at customer sites, and is usually connected to the distribution system. It can be contrasted to the traditional model of larger-scale and centralized electricity generation that is located a substantial distance away from load.

DG can be either a demand-side or supply-side resource, or a combination of both. While DG potential is not presented as a separate resource option, some of the potential considered within DSM and the supply-side resource options would qualify as DG.

Based on feedback received during the development of the Net Metering Evaluation Report No.3,[42] coupled with a review of current DG processes, BC Hydro identified gaps in its existing processes and developed an approach on how to bridge those gaps with a seamless suite of offers that span demand-side and supply-side opportunities. Next steps include increasing the Net Metering cap from 50 kW to 100 kW for commercial, institutional, industrial, municipal and First Nations customers, provided there will be no adverse cost impacts on non-participating ratepayers; and begining the design of a streamlined acquisition process that

[42] BC Hydro submitted its Net Metering Evaluation Report No. 3 to the BCUC on April 30, 2013; copy available at www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html.

supports small-scale DG projects (50 kW to 1 MW) under the umbrella of the current Standing Offer Program.

3.6.2 Evolving Generation Technology

3.6.2.1 Hydrokinetic

Hydrokinetic energy – also called ‘river in-stream’ or ‘river current’ energy – refers to the kinetic energy from flowing water in rivers. Hydrokinetic energy systems convert the kinetic energy in free-flowing rivers into electricity without the use of dams or diversions. Unlike conventional hydroelectric systems, hydrokinetic systems do not require a hydraulic head, depending rather on the swift-moving river similar to tidal current or wind energy systems.

BC Hydro is monitoring the development of these technologies and assessments of their resource potential. Hydrokinetic resources may be updated in subsequent resource option estimates following completion of the proposed National Resources Canada study to assess the hydrokinetic resource potential in Canada. BC Hydro has worked with technology suppliers to host a field test of vertical-axis hydrokinetic devices in a controlled environment downstream of the Duncan Dam. There are currently no active hydrokinetic demonstration projects in B.C.

3.6.2.2 Storage Technologies

Energy storage is now recognized as a key component of future grid asset management and operations. Recent advances in the development of energy storage have focused on numerous technologies for a variety of functions within the electrical grid system. Besides PS, other technologies include compressed air energy storage, capacitors, flywheels, batteries and hydrogen fuel cell storage systems.

BC Hydro is monitoring the development of these storage technologies; more information on their commercial status can be found in Appendix 3D of the IRP. BC Hydro is advancing a demonstration of advanced batteries to improve system reliability with support from the Federal Government’s Clean Energy Fund, as well as the evaluation of community-scale energy storage technologies in test environments. None of these technologies are considered to be within the scope of the IRP planning horizon.

3.6.3 Emerging Transmission Technology

3.6.3.1 Advanced Conductors

BC Hydro currently relies on a network of overhead, subterranean and submarine aluminum-steel compoSite Cables to conduct power at high voltage from generating stations to the load centres. BC Hydro monitors research developments for advanced conductor technologies which seek to utilize emerging materials to increase the conductivity and/or strength of transmission cables. These advances have the potential to reduce transmission system costs and energy losses.

One of the areas being monitored is high-temperature superconductors (**HTS**), which are materials that lose all resistance to electrical conduction at temperatures above the boiling point of nitrogen. HTS transmission cables are currently in demonstration in several North American and Asian jurisdictions.

3.6.3.2 Advanced Materials for Transmission Structures

BC Hydro is investigating the potential for new materials to improve the performance, cost and safety of towers and poles used to suspend overhead conductors. Three current areas of interest are: composite materials to replace wood or steel support structures; coatings for corrosion protection, and; new materials and designs to replace structural guidelines.

3.6.3.3 Real-Time Condition Assessment and Control

The term ‘Smart Grid’ describes the integration of power system management and communications that enable monitoring and automatic optimization of interconnected elements of the grid. Within the context of the transmission system, which already exhibits many of the attributes of a Smart Grid, there are advanced monitoring and control technologies becoming available that allow transmission networks to operate more efficiently and reliably. BC Hydro is working to evaluate and/or deploy advanced sensors and the integration of the collected data into control systems as part of its Smart Grid initiative.

3.6.3.4 Next-Generation Stations

Advances in information technology, communication infrastructure and power system technologies are driving innovations towards next-generation stations. These stations will transform voltages and manage power flow with greater control and with a smaller physical footprint. The main power apparatus in a next-generation station, such as circuit breakers and transformers, will be smaller, while elements such as busbars, insulators and ground grids will be more densely packaged. The sensors and communication modules will be embedded in the power apparatus and primary high voltage measurements will utilize high-accuracy optical devices with direct digital outputs. This will allow new approaches for monitoring, control and protection including reduced wiring, reliable and accurate filtering of data, improved data security, self-diagnosis of problems, and industry standard approaches for information exchange. The systems will be modular, allowing low cost expansion capabilities. Next-generation stations are currently in the demonstration/early deployment stage of development.

3.7 Resource Screening

For a variety of reasons, not all of the resource options identified can be considered for the purpose of meeting BC Hydro’s energy and capacity load-resource gaps. Legislation, government policy, economic feasibility, technical viability and historical experience are some factors that must be used to determine the most appropriate resource options for IRP analysis. The following sections discuss why some resources were screened but not included in the portfolio analysis.

3.7.1 Category 1: Legally Barred Options

This category of resource options have either been legislatively barred (i.e., Burrard, the large hydroelectric projects prohibited by the *CEA*, and external markets) or barred by policy (e.g., nuclear). Therefore, they have not been included in the base portfolio analysis, and in the case of external markets are only used as a bridging or contingency resource option. Bridging and contingency resource recommendations are discussed in Chapter 9.

- Burrard Thermal Generating Station: Burrard is an existing resource that is already being relied on to the extent permitted under sections 3(5), 6(2)(d), and 13 of the *CEA,* which provides that the Burrard firm energy contribution is 0 GWh/year, and the Burrard Thermal Electricity Regulation[43] 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. After this, BC Hydro will only be able to operate Burrard for emergency or voltage support purposes.
- Large Hydro: Sections 10 and 11, and Schedule 2, of the *CEA* 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 River Diversion. Cutoff Mountain on the Skeena River and McGregor River Diversion are also legislatively barred by, respectively, (1) the B.C. *Fish Protection Act*,[44] which designates the Skeena River as a "protected river" and prohibits the construction of bank-to-bank dams, and (2) the B.C. *Water Protection Act*,[45] which prohibits the construction of "large-scale projects" such as McGregor River Diversion capable of transferring a peak instantaneous flow of 10 or more cubic metres per second of water between major watersheds.
- External Markets: Pursuant to subsection 6(2) of the *CEA*, 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

[43] B.C. Reg. 319/2010.
[44] S.B.C. 1997, c.21.
[45] R.S.B.C. 1996, c.484.

from DSM savings and electricity "solely from electricity generating facilities within the Province". As a result of the legal requirement for self-sufficiency, the following external market/import energy and capacity resources are not available to BC Hydro for long-term planning purposes:

- The spot electricity 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 along the Columbia River in the U.S. as a result of provisions in the Columbia River Treaty of 1961 because the Canadian Entitlement is produced from electricity generating facilities in the U.S. and is merely delivered to the U.S./B.C. border

- Nuclear: Policy Action No. 23 of the 2007 BC 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,[46] 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.

3.7.2 Category 2: Currently Unviable Options

These resource options were not used in the portfolio analysis because they are at a less advanced stage of technological maturity, they appear to face developmental challenges, and/or they have not yet been proven to be economically feasible:

- Pumped Storage at Mica: BC Hydro undertook a pre-feasibility study and cost estimate of adding a PS facility at Mica dam, and these formed the basis for the information presented earlier in section 3.4.2.1. However, because this is a

[46] Society of Ontario Hydro Professional and Administrative Employees v. Ontario Hydro. 1993. 3 S.C.R. 327 (S.C.C.).

discrete project whose technical feasibility has not been specifically confirmed, it was not included as a resource option in the portfolio analysis.

- Offshore Wind: This category contains potential offshore wind turbine sites. There are no operating commercial offshore wind power production sites in B.C. at this time.
- Geothermal: Geothermal appears to be a low-cost resource option but has never been bid into a BC Hydro power acquisition process by an IPP. There are no commercial geothermal electricity projects in B.C. at this time. BC Hydro understands that there are some challenges with geothermal development in B.C. related to making significant upfront capital investment at the early exploration and initial production drilling stages.
- Wave: Currently, there are five generic approaches to capturing the wave energy resource, all of which are at the early stages of commercial development yet have potential application in B.C. There are currently no wave energy projects in B.C. waters, although two demonstration projects have received support from provincial and federal innovative clean energy funding agencies. In addition, the UECs for wave resources are much higher than for viable supply-side resources such as run-of-river, onshore wind and biomass.
- Tidal: There currently are no commercial tidal current projects in B.C. although there are two demonstration projects underway. There is also very little worldwide experience with commercial-scale tidal projects and their costs. In addition, the UECs for tidal resources are much higher than for viable supply-side resources.
- Solar: Both the photovoltaic and CSP technologies are commercially proven. Globally the costs have achieved a dramatic decline, but while this trend is projected to continue, costs are not expected to become 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. In addition, the UECs for solar resources are much higher than for viable supply-side resources.

- Coal-Fired Generation with CCS: Policy Action No. 20 of the 2007 BC 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 emissions". There are also a number of legal/regulatory and public acceptance issues that likely need to be addressed before CCS technology can be considered on a commercial scale in B.C.

3.7.3 Category 3: DSM Options 4 and 5

As described in section 3.3.1, BC Hydro has developed a number of DSM options with a range of savings from meeting the 66 per cent DSM objective to the largest amount of conservation BC Hydro deemed theoretically possible at this time. These options have both energy and capacity savings. They include BC Hydro's traditional DSM initiatives (with progressively increasing activities on programs for Option 1, Option 2/DSM Target and Option 3) as well as two additional, more aggressive DSM options (Options 4 and 5) which further increase savings via more aggressive conservation rate structures, and codes and standards.

DSM Options 4 and 5 were designed in collaboration with BC Hydro's Electricity Conservation and Efficiency Advisory Committee and were intended to look at a fundamental shift in BC Hydro's approach to saving electricity. Both DSM Option 4 and DSM Option 5 tactics go well beyond the current Option 2/DSM Target and would be new and untested, and therefore it is uncertain to what extent they would succeed in generating additional electricity savings. While DSM Options 4 and 5 demonstrate what is theoretically possible, BC Hydro concludes that they are not technically viable options for prudent utility planning at this time for the reasons summarized below:

- It is uncertain whether the Option 4 and Option 5 tactics would be accepted by government, customers and the BCUC. DSM Options 4 and 5 present significant government and customer acceptance challenges arising from BC Hydro's reliance on an aggressive and untested coordinated combination of rate structures, codes and standards because of:
  - Rate structure and aggressive pricing: Both DSM Option 4 and Option 5 require Provincial Government, customer and BCUC acceptance of rate structures that expose customers to higher, marginal cost price signals to a much larger extent.

    In the case of DSM Option 4, BC Hydro's large industrial customers would be exposed to a greater extent to marginal cost price signals because the Transmission Service Rate would change from a 90/10 to a 80/20 split between Tier 1 and Tier 2 prices, thereby increasing the amount of energy consumption that is subject to Tier 2, marginal cost pricing. There would also be efficiency-based pricing for commercial customers which would consist of either a connection fee tied to building energy performance or an initial energy baseline rate structure for new buildings.

    In the case of DSM Option 5, all BC Hydro customers would be exposed to marginal cost price to a greater extent.
  - Significant move from incentive approach in DSM to mandatory actions that requires government intervention and regulation: Both DSM Option 4 and DSM Option 5 would require significant government intervention and regulation at both the Federal Government and Provincial Government level as well as industrial customer buy-in to individual facility certification:

    Both DSM Option 4 and DSM Option 5 require that each BC Hydro 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 higher marginal rates. This would raise the issue of the Heritage contract at both a political and regulatory level and in particular the basis for distributing the low embedded cost of service Heritage hydroelectric resource energy among BC Hydro's existing and future customers. The Heritage contract became law through the BC Hydro Public Power Legacy and Heritage Contract Act (S.B.C. 2003, c.86) and Heritage Special Direction No. 2 to the BCUC (B.C. Reg. 158/2005). The Heritage contract ensures that electricity generated from BC Hydro's Heritage resources continues to be available to BC Hydro ratepayers based on cost of service, and not market prices. In November 2008, the Provincial Government signed Order in Council No. 849/2008, establishing the Heritage contract in perpetuity.

DSM Option 5 goes further with a requirement that in the industrial sector, individual plants would require certification. Government regulation would require buildings to be net-zero consumers of electricity.

- When adjusted for deliverability risk, preliminary analysis indicates that Options 4 and 5 are more expensive than the other DSM options considered
- The significant range of uncertainty around the sizeable capacity savings for Options 4 and 5 could jeopardize BC Hydro's ability to serve its customers

3.7.4 Category 4: DSM Capacity Options

While the aforementioned DSM options have capacity savings associated with their energy savings, additional capacity savings may be possible through specifically targeted DSM activities, referred to as peak reduction or peak shaving. As described in section 3.3.2, capacity-focused DSM savings were grouped into two broad categories – industrial load curtailment and capacity-focused programs.

At this point in time, 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.

3.7.5 Viable Resources

Chapter 4 of the IRP sets out the framework BC Hydro used to evaluate the viable resource options, which are as follows:

- DSM Options 1, 2 and 3
- Site C
- Run-of-river hydroelectricity
- Onshore wind
- Biomass (wood-based and MSW)
- Resource Smart projects
- Natural gas-fired generation (CCGTs, SCGTs and cogeneration) within the *CEA* parameters
- Pumped storage other than PS at Mica.