Exhibit CAC# 45-15

CAC Manitoba: Book of Documents
NFAT Review

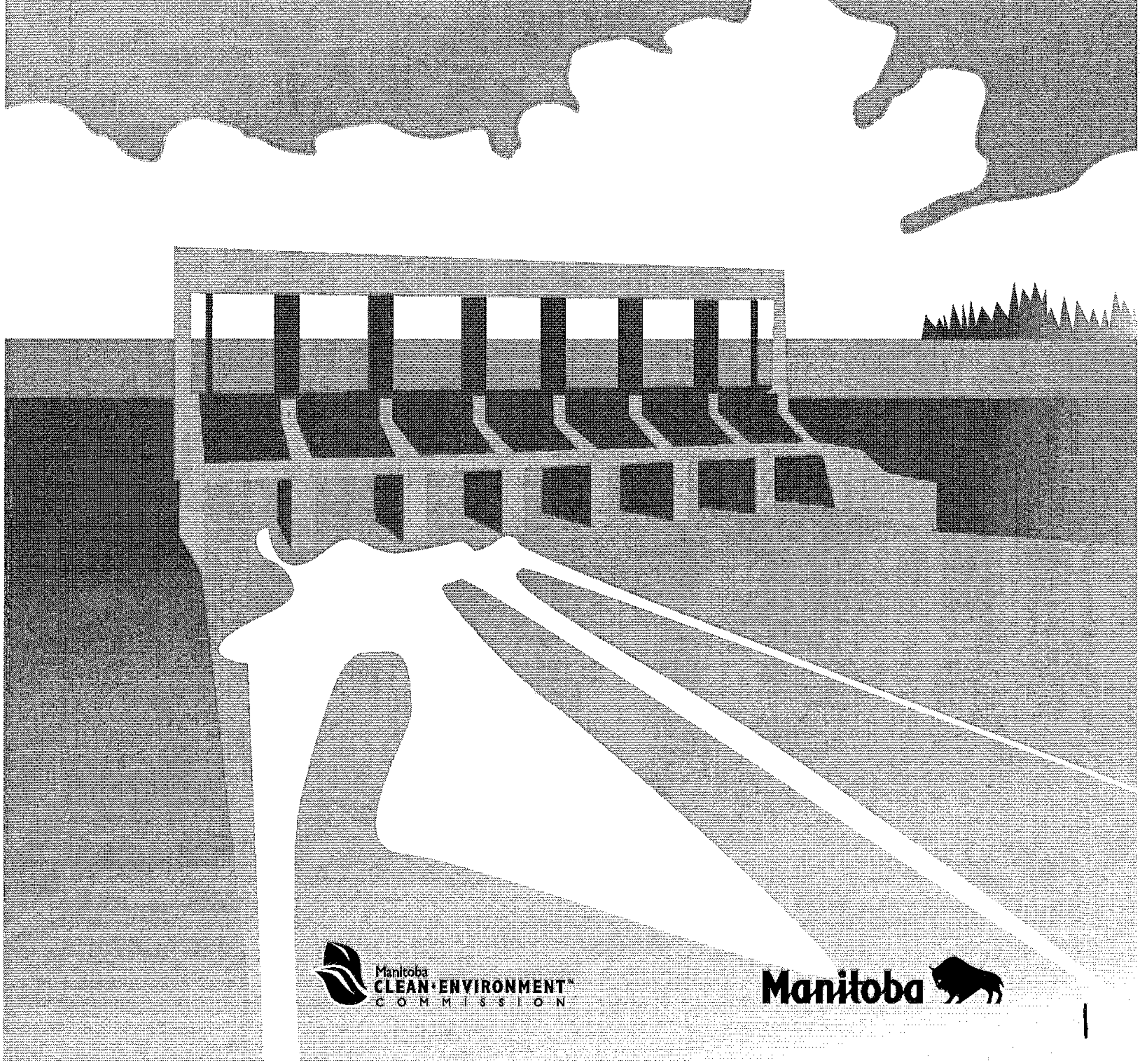
Tab	Document
1	Clean Environment Commission, *Report on Public Hearing: Keeyask Generation Project*, April 2014 p. 137-140
2	BC Hydro, *Integrated Resource Plan: Chapter 4 – Resource Planning Analysis Framework*, November 2013

TAB 1

REPORT ON PUBLIC HEARING

Keeyask Generation Project

April 2014



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of hydroelectric development regionally. Representatives of Peguis First Nation (PFN) stated that the Keeyask CEA should have considered all the connected waterways that are managed for electrical production by Manitoba Hydro, including Lake Winnipeg. An expert witness testifying for PFN demonstrated a technique for visualizing and estimating the historic impact on waterways throughout northern Manitoba as a result of CRD, LWR, the Nelson River dams and the Grand Rapids dam on the Saskatchewan River. The process involves collecting historical maps from before hydroelectric development, scanning the maps, correcting for inaccuracies, and comparing them to scanned versions of contemporary maps of the same area. The data from the scanned maps are turned into a kind of computer file called a shapefile, which then allows the computer to calculate the area flooded (or dewatered) in each area by the various developments. Adding up all the flooding from all the projects, the expert witness found that approximately 135,000 hectares (1,350 square kilometres) had been flooded in northern Manitoba as a result of hydro development.

Representatives of Pimicikamak Okimawin stated that the scoping of the Keeyak EIS failed to consider cumulative effects of all the hydroelectric projects that have affected their community. Community members and representatives spoke extensively of the impacts they have felt as a result of the regulation of Lake Winnipeg water levels, including shoreline erosion, debris, damage to fishing, unpredictable ice levels, and impacts on ice travel. They argued that Aboriginal people in the region do not see each hydro development as an individual project, but as part of one large project.

An expert witness testifying for Pimicikamak suggested that one way to better consider the cumulative effect of all the hydro projects might have been to designate as a VEC "the naturally functioning riparian corridor of the Nelson River." Such an approach would have considered the existence, or not, of a naturally functioning riparian corridor all along the Nelson. Another alternative suggested by this expert witness would have been to designate "the natural hydrological regime" as a VEC. Doing so would have allowed the EIS to consider the existence, or not, of natural flow conditions all along the Nelson River, and the impact they have on habitat and other aspects of the environment. The expert witness also argued that one cumulative effect of an additional generating station on the Nelson River is that, with more money invested on the river in power generation, there will be more incentive to manage water flows on the river only for power generation, at the expense of the environment.

Individual Presenters, both during the hearings held in northern Manitoba and in Winnipeg, spoke frequently about cumulative effects. Many presenters said that, from their point of view, all the hydroelectric developments in the north are part of a single on-going project and so they cannot be separated. The point was frequently made that the water that will turn the turbines at Keeyask flows past other communities as it makes its way down the watershed. Many presenters spoke about effects on fishing, navigation, water quality, recreation, aesthetics, culture and spirituality resulting from LWR, CRD, Kettle, and other major projects.

Commission Comment – Cumulative Effects Assessment

The Panel recognizes the great deal of effort put into the assessment of Project effects. The direct effects assessment was

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very well done and the cumulative effects assessment was a great improvement over past project assessments. However, the Panel still has some concerns about the CEA, specifically, regarding the delineation of the study area and the quantification of cumulative effects for the terrestrial environment. As well, conclusions regarding the lack of adverse cumulative effects in the aquatic environment and in the socio-economic environment appear to be based on optimistic assumptions about the success of mitigation measures.

The Proponent's use of an ecological boundary for the terrestrial environment study area resulted in the exclusion of a number of past and future projects. Study Zones 5 and 6, which were used for cumulative effects assessment for many VECs, extended only as far east as the Long Spruce Generating Station, excluding the Henday Converter Station, Limestone Generating Station, the future Keewatinoow Converter Station, part of the Bipole III transmission line and the proposed Conawapa Generating Station from the study areas for these VECs. When asked to assess impacts of disruptions in an extension area that included these projects, the Proponent indicated that various aspects of Bipole III (including Keewatinoow) and Conawapa will affect an additional 3,174 hectares of land, while existing projects in this extension area impact 1,297 hectares, for a total of 4,471 hectares.

One of the significant questions, raised by the witnesses for the CAC, was whether, in assessing cumulative effects, we should consider that new impacts are minor in comparison to past impacts, or consider that, since past impacts were significant, any new impact will add to that significant disruption. The Commission agrees that for most VECs, Keeyask will not add substantially to what has occurred over the past 50 years. For sturgeon and woodland caribou, however, there is the potential for the combination of past, present and future projects to have a significant cumulative effect. This is especially the case if the mitigation measures for sturgeon are not successful. For caribou, until the "summer resident" herd and its range can be better defined, the degree of uncertainty about effects or mitigation will be great.

The Keeyask EIS would have benefited if the Proponent could have made use of data collected in research for the Bipole III Transmission Project. Through a series of requests for information regarding cumulative effects boundaries, VECs and habitat modelling, it was discovered that there was an incompatibility in data collection and analytical methodologies between the Bipole III and Keeyask Generation Projects. Vegetation cover data that had been classified in a Bipole III-specific database would have been useful in delineating and confirming the distribution of vegetation cover classes in the Keeyask area. The Commission also pointed out to the Proponent that there were areas of overlapping impact between the two projects where there would be effects on VECs that were assessed in one or both of the project environmental impact statements, including beaver, moose, caribou, American marten, mallard, bald eagle, olive-sided flycatcher, rusty blackbird and common nighthawk. The Proponent responded that, given the time available, it would be impossible to meld the data sets from the two EISs in order to add information on Bipole III impacts to the Keeyask CEA, as different data collection and analysis methodologies had been used. The Panel considers this a great loss of valuable information that could have better informed the Keeyask assessment.

Another important question raised in the critique of the Proponent's CEA practice concerned the decision not to conduct a

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cumulative effects assessment for VECs that are not expected to have a negative impact from the Project. There would be less possibility of small impacts adding up to something substantial (the oft-stated "death by a thousand cuts") if all VECs, regardless of the assessment of individual impacts, were considered in the CEA.

The Panel also found that the Keeyask EIS lacked quantification of the cumulative effects of past, present and future projects for many VECs. When asked in an Information Request to quantify the effects of past and existing projects, the Proponent responded that data are not available to determine the specific habitats that might have existed prior to the beginning of industrial development in the region. The CEC suggested an approach for quantifying the effects of past and present projects on many VECs. This approach was based on determining the ratio of current habitat for a given VEC species relative to all current habitat in the area and then multiplying that by the total pre-development habitat. While it may not be exact, it provides some illustration of how much habitat has been lost. The ratio is below:

Using this formula, it becomes possible to have at least some understanding of the cumulative effects of past developments in the study area on various VECs. When asked to employ this formula, the Proponent found that cumulative effects on several VECs exceeded their own benchmarks. Specifically, olive-sided flycatcher, rusty blackbird, common nighthawk and beaver had all lost amounts of habitat within their Regional Study Areas in excess of the Proponent's benchmark.

In response to questions about the cumulative loss of habitat, especially for the three songbirds that are species at risk, the Proponent stated that the displaced animals would be able to find other available habitat in the larger region. Along these same lines, the Panel considered that the Proponent did not make sufficiently consistent use of benchmarks for all VECs.

Ultimately, the Panel agrees that the threats to these three songbirds are not a result of habitat loss in northern Manitoba, but threats to habitat elsewhere in their range. The Panel also agrees that beaver populations are not under threat in Manitoba and will not be affected by a larger-than-originally-stated loss of habitat in the immediate area of the Project. However, a more rigorous evaluation would provide greater confidence in the conclusions, and it is essential that monitoring be done to confirm these conclusions or undertake further mitigation measures should significant negative impacts be identified.

Like many Participants and Presenters, the Panel believes that the Proponent has placed a great deal of confidence in its mitigation measures. This is particularly the case with regard to the habitat construction and stocking measures planned for lake sturgeon. The assumption that these measures will be successful has allowed the Proponent to judge that there will be no adverse cumulative effects from Keeyask and, in fact, a positive impact. In the same way, the Proponent has placed confidence in its mitigation measures for social impacts, such as those intended to prevent negative interactions between community members and Project workers. In these areas, monitoring will be extremely

$$\frac{\textit{VEC current habitat}}{\textit{Total habitat available}} \times \textit{Total pre-development habitat} = \textit{Total VEC Habitat Lost}$$

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important in order to determine if these optimistic assumptions are misplaced and to determine if adaptive management measures are needed to respond to unexpected problems.

The Panel heard many Participants and Presenters refer to the need for a Regional Cumulative Effects Assessment, which would consider all of the effects of hydro development along the Nelson and Churchill Rivers. It was frequently pointed out that the Commission had made a recommendation for such an assessment in its report on the Bipole III Transmission Project, and it was recommended that a licence for Keeyask be withheld until such an assessment is completed. The Panel has heard that Manitoba Hydro is working with Manitoba Conservation and Water Stewardship on defining such a study and expects to have it completed in 2015. The Panel is aware that a great deal of research has been undertaken on the environment in the Churchill-Nelson region and believes that much baseline information for a Regional CEA is already available. The Keeyask hearing reinforces the conclusion that a Regional CEA needs to be carried out.

In many of our reports, over the past decade, the Commission has made specific recommendations to both the Manitoba Government and to proponents aimed at improving the practice of cumulative effects assessments in Manitoba. We continue to stand by those recommendations and believe that a similar recommendation is, again, warranted.

Non-Licensing Recommendation

The Commission recommends that:

12.1 The Manitoba Government establish provincial guidelines for cumulative effects assessment best practices and include specific direction for proponents in project guidelines.

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TAB 2

BC hydro

Integrated Resource Plan

Chapter 4

Resource Planning Analysis Framework

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4.1 Introduction

BC Hydro's planning environment is dominated by three overarching uncertainties – load growth, Demand Side Management (**DSM**) deliverability and market conditions. This chapter sets out the analytical framework that BC Hydro used to compare resource alternatives, addressing multiple objectives, attributes and uncertainties. The following four criteria were adhered to in the analysis:

- Meeting BC Hydro's planning criteria (described in section 1.2.2)
- Achieving the *Clean Energy Act* (***CEA)*** subsection 6(2) requirement that BC Hydro be self-sufficient in energy and capacity by F2017 and each year after that[1]
- Meeting *CEA* subsection 2(c) 93 per cent clean or renewable energy objective
- Ensuring that at least 66 per cent of BC Hydro's expected incremental load growth is met by DSM as set out in subsection 2(b) of the *CEA*

As this chapter demonstrates, BC Hydro has sufficient resources to meet growing electricity demand over the short to mid-term[2] planning period, but will need to acquire new resources towards the middle and end of the planning horizon assuming implementation of the DSM target and Electricity Purchase Agreement (**EPA**) renewal assumptions described in this chapter, with or without Expected liquefied natural gas (**LNG**) load. This splits the analytical framework into two separate but interrelated parts, focused on shorter-term and longer-term planning issues.

The remainder of this chapter is organized as follows:

[1] Except as noted in the section 9.2.7 recommendation concerning the two-year economic bridging to Site C's in-service date (**ISD**).

[2] For the purposes of the Integrated Resource Plan (**IRP**), events occurring before F2018 are considered short-term and events occurring beyond F2023 are considered long-term. The boundaries between short, mid and long term are treated loosely as no analytic results turn on their exact definitions.

- Section 4.2 covers the short to mid-term planning period and outlines the key questions, decision objectives, uncertainties and the planning analysis framework over that period, with an emphasis on managing costs. It presents the associated analyses and recommendations, and concludes with recommended short-term actions and options to manage costs
- Sections 4.3 and 4.4 focus on the long-term planning horizon and outline the key questions, decision objectives, uncertainties, and planning analysis framework to address resource planning questions over that period

Building on this chapter, Chapter 6 takes the short-term cost management conclusions and describes the analysis undertaken to determine what actions and resources should be considered to meet the identified need for energy and capacity over the longer term. The framework described in this chapter, and the corresponding results presented in Chapter 6, led BC Hydro to select the Recommended Actions that are found in Chapter 9.

4.2 Short-Term Energy Supply Management

The Load-Resource Balances (**LRBs**) shown in Chapter 2 establish that a gap exists for energy and for capacity from the start of the planning period in F2017 and onward before accounting for DSM and the other incremental resources outlined in Table 4-1. The incremental resources listed in Table 4-1 have volumes that are generated for illustrative purposes, but that correspond to the quantity of cost-effective resources available at or below the Long Run Marginal Cost (**LRMC**) price of $135/MWh that was used by BC Hydro in the past based on the Clean Power Call results. As such, they form a baseline of "typical" resource planning volumes against which alternative short-term expenditures can be compared.

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Table 4-1 Detailed Assumptions Regarding Incremental Resources in F2017

Resources	Contracted Energy[3] (GWh/year)	Firm Energy (post-attrition, GWh/year)	Effective Load Carrying Capability (ELCC) (post-attrition, MW)	Notes
Supply-Side Resources				
New EPAs: Standing Offer Program (**SOP**)	1,000	520	29	Incremental EPAs awarded under BC Hydro's SOP
New EPAs: Impact Benefit Agreements (**IBAs**)[4]	0	0	0	
Independent Power Producer (**IPP**) EPA Renewals	1,243	1,205	137	
Demand-Side Resources				
Smart Metering and Infrastructure (**SMI**) Program	n/a	65	9	Commencing in F2017, forecast theft detection benefits are expected as a result of the SMI program.
Voltage and Var Optimization (**VVO**)	n/a	359	1	Reduced energy consumption by optimizing the distribution-supply voltage for distribution customers.
DSM	n/a	5,127	781	Iincremental savings that are targeted as part of pursuing the 2008 Long Term Acquisition Plan (**LTAP**) DSM target

3 Estimated total energy (firm plus non-firm).

4 Approximately 170 GWh/year of firm energy and 25 MW of ELCC beginning in F2020.

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4.2.1 Short-Term Load Resource Balances

Figure 4-1 and Table 4-2[5] show the energy LRBs, and Figure 4-2 and Table 4-3 show the capacity LRBs, after implementation of the Table 4-1 resources, including the 2008 LTAP DSM target:

- The Table 4-1 incremental resources address the energy and capacity gap without Expected LNG until F2025 and F2019 respectively, with temporary planning surpluses in the near and mid-term
- A temporary planning surplus continues to exist with Expected LNG of 3,000 GWh/year and 360 MW – the energy and capacity gaps emerge in F2022 and F2019 respectively

As there is no need for incremental resources in the near to mid term of the planning horizon, the inclusion of these incremental resources bears scrutiny to reduce costs in the short term, regardless of the potential demand from LNG.

[5] BC Hydro has summarized LRBs and surplus/deficit values in this chapter with respect to key milestone years: F2017 (self-sufficiency target year and start of the planning horizon) through F2023; F2028; and F2033 (final year of the planning horizon).

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Figure 4-1 Energy Surplus/Deficit with Incremental Resources

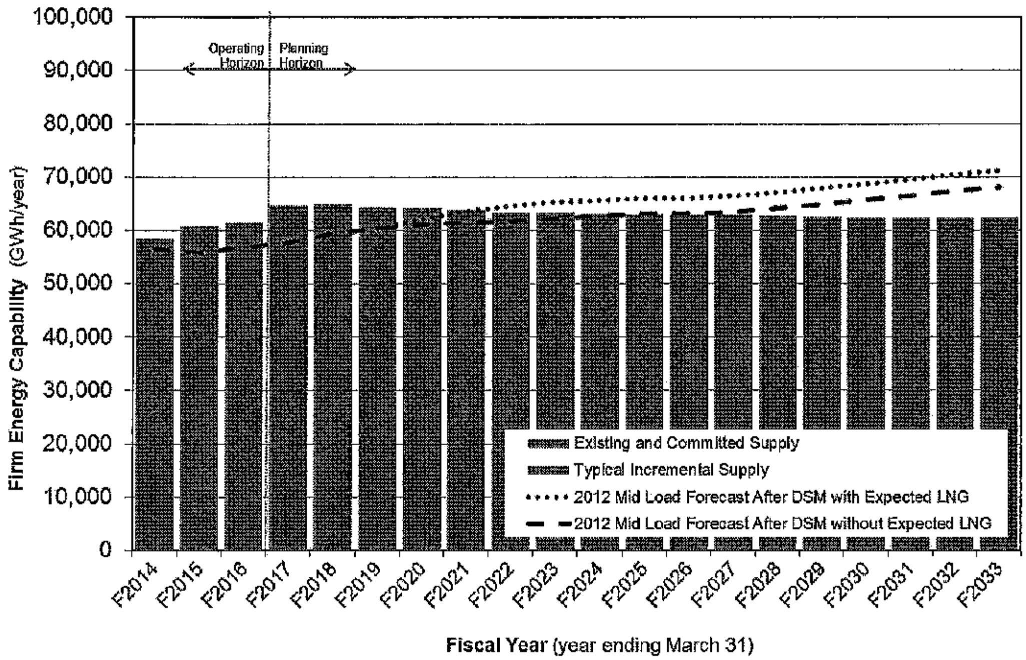
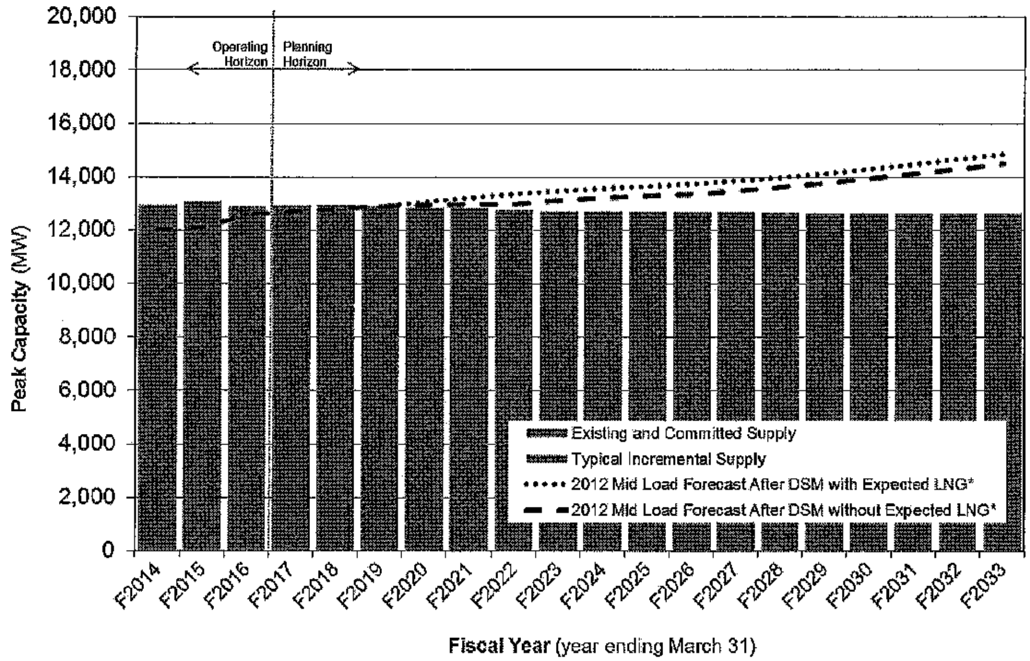


Table 4-2 Energy Surplus/Deficit with Incremental Resources, GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	6,913	5,351	3,899	2,101	406	-1,298	-2,056	-4,427	-8,706
Surplus/Deficit with Incremental Resources without Expected LNG	6,913	5,351	3,899	3,101	2,406	1,702	944	-1,427	-5,706

Figure 4-2 Capacity Surplus/Deficit with Incremental Resources



* Including planning reserve requirements

Table 4-3 Capacity Surplus/Deficit with Typical Incremental Resources, MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	240	135	-15	-213	-384	-608	-762	-1,321	-2,237
Surplus/Deficit with Incremental Resources without Expected LNG	240	135	-15	-93	-144	-248	-402	-961	-1,876

The following sections describe ways in which short-term costs can be reduced through various actions.

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4.2.2 Key Questions to be Addressed Over the Short to Mid-Term Planning Horizon

BC Hydro explored four sets of actions for reducing costs over the short to mid-term planning horizon:

(a) Reduce spending on Independent Power Producer (**IPP**) resources

(b) Delay planned ramp-ups in spending on DSM initiatives

(c) Scale back implementation of BC Hydro's VVO program

(d) Create industrial customer incentive mechanisms to temporarily increase demand.

The following three sections lay out the framework for creating and comparing different options.

4.2.3 Key Decision Objectives to Design and Compare Options

Chapter 1 describes the sources and rationale for considering multiple planning objectives within this IRP, including: the *CEA* British Columbia's energy objectives and requirements; good utility practice; and statutory obligations such as the *Utilities Commission Act* (***UCA***) service obligation. Table 4-4 presents decision objectives compiled by BC Hydro to inform either the design or the comparison of methods to reduce energy portfolio expenditures over the short to mid-term planning horizon of this IRP.

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Table 4-4 *CEA* and Other Resource Planning Objectives

Decision Objective	Reason for Inclusion
Minimize Financial Impacts, including: • Cost (various measures) • Cost uncertainty	Good utility practice; First Nations, public and stakeholder interests; align with *CEA* 'ratepayer impact' objectives grouped in Table 1-1
Maximize Economic Development • Foster development of First Nations' communities • Foster development of rural communities	First Nations, public and stakeholder interests; align with *CEA* 'economic development' objectives grouped in Table 1-1
Maximize System Reliability • Minimize DSM deliverability risk	Good utility practice; First Nations, public and stakeholder interests
Maintain or Improve Relationships • Customers • IPP industry • First Nations	Good utility practice; First Nations, public and stakeholder interests
Maximize Equity of Opportunities	Good utility practice; First Nations, public and stakeholder interests

4.2.3.1 Financial Impacts

The *CEA* and good utility practice point towards the importance of tracking costs when comparing resource options. Costs are expressed on a Present Value (**PV**) basis to capture the impact of the timing of costs and trade revenues over the planning horizon. Where uncertainty is relevant, cost ranges or costs across scenarios are highlighted.

4.2.3.2 Economic Development Impacts

Consistent with subsection 2(k) and 2(l) of the *CEA*, BC Hydro considered the economic development potential of resources, and the development of First Nations and rural communities through the use of clean or renewable resources. Some future potential IPP EPAs are tied to IBAs signed with specific First Nations. The existence of these IBAs was one of several factors used to determine which IPP EPAs would be included as resources during the near to mid-term period of the planning horizon when self-sufficiency needs are met.

4.2.3.3 Maximize System Reliability

BC Hydro treats the planning criteria described in section 1.2.2 as a constraint that is not traded off against other objectives. However, some resource choices can work towards or against achieving reliability beyond the planning criteria; once the planning criteria are met, reliability can be traded off against other objectives. In this IRP, such instances might occur over the short to mid-term planning horizon, depending on the degree to which DSM is included in the portfolio.

4.2.3.4 Maintain or Improve Relationships

The ability of BC Hydro to meet future energy and capacity needs is tied to the business relationships it has developed to pursue supply-side resources and DSM initiatives. On the supply-side, maintaining BC Hydro's business reputation (including relationships with IPPs) was one consideration when assessing how EPAs would be handled during the near to mid-term planning period. On the demand-side, maintaining ties to industry that would allow BC Hydro to ramp up future DSM activities was a key design criterion for the short-term period over which DSM expenditures are to be moderated.

4.2.3.5 Maximize Equity of Opportunities

Equity was an important design criterion for DSM and potential customer incentive mechanisms:

- Access to DSM initiatives in general, and the inclusion of a low income DSM program in particular, were key design criteria used to ensure customers would have access to DSM opportunities to lower their bills
- Section 4.2.5.4 discusses potential incentive mechanisms for customers to access, on a temporary basis, energy in excess of BC Hydro's system needs. One design criterion for such incentive mechanisms will be that access to them does not unfairly benefit particular customers within an industrial sector.

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4.2.3.6 IRP Treatment of Multiple Decision Objectives

BC Hydro used the decision objectives described in sections 4.2.3.1 to 4.2.3.5 to design and compare optional ways of reducing costs over the short term. Consistent with the British Columbia Utilities Commission's test and as highlighted in Table 1-1, the goal is not to arrive at the least cost solution, but rather the most cost-effective solution which entails among other things consideration of risk. Since the role of these objectives in the design of options and the impact of the options on these objectives have not been quantified in many cases, the appropriate balance amongst these objectives to achieve the most cost-effective solution has been a matter of professional judgment.

4.2.4 Key Uncertainties Over the Short to Mid-Term Planning Horizon

To provide a clear discussion of the uncertainties and risks that BC Hydro is managing, the following definitions are provided:

- Uncertainties are variables with unknown outcomes
- Risk is commonly defined as the effect of uncertainty on objectives.

Some key uncertainties and related risks for addressing resource needs over the short to mid term include:

(a) Cost risk, particularly the chance that activities to generate short-term cost reductions (e.g., reduction in DSM activities, temporary load additions) are more than offset by future cost increases

(b) Load growth and the chance that load growth exceeds or falls below expectations

(c) DSM initiatives and the uncertainty whether DSM savings can be ramped up quickly to higher levels of savings in response to emerging energy and capacity needs

(d) IPP attrition rates from power acquisition processes and the chance that they are lower than expected, adding to cost through additional energy purchases when the energy is not needed.

4.2.5 Methods to Reduce Costs Over the Short to Mid-Term Planning Period

This section lays out the framework used to assess potential actions and displays anticipated changes to the LRBs. It concludes with the cumulative impacts to the LRBs.

4.2.5.1 Reduce Spending on EPAs

One potential method considered to decrease energy costs during the short to mid-term period after self-sufficiency is achieved is to reduce spending on the contracted energy supply (i.e., EPAs). This section identifies three categories of potential opportunities to reduce EPA volume and/or cost and then addresses the method for identifying and selecting specific reduction opportunities. It concludes with a summary of how actions taken to date and actions recommended within this IRP will impact the LRB.

BC Hydro identified three categories of potential EPA portfolio supply reductions:

(i) Pre-COD EPAs where there is some ability to defer Commercial Operation Date (**COD**), downsize capacity or terminate the EPA

(ii) EPA renewals where contracts are expiring

(iii) New EPAs

For all three categories, EPAs were assessed based on:

- Cost - BC Hydro examined the potential PV of energy savings against two bookends to inform decisions: (a) termination of the EPA; and (b) continuing with the EPA. For cases where the continuation of the EPA is under

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consideration, options for downsizing project size or deferring COD were pursued.

- Implementation risk – This risk encompasses factors such as: First Nations relationship risk (e.g., loss of economic, training or employment opportunities for First Nations - in some cases a First Nations IBA has been executed with the IPP proponent); reputational risk (e.g., the perception that BC Hydro lacks integrity in managing its contractual obligations under these agreements); other stakeholder risk (e.g., loss of economic benefits for communities); and litigation risk (e.g., pay out of damages exceeds savings)
- System Benefits – These benefits could include factors such as capacity contribution to generation operations and local transmission, and capital and/or operating cost reductions. For example, bioenergy projects can provide hourly firm capacity.
- Economic Development Benefits – In some cases, local communities and First Nations strongly support the development of power generation projects due to economic benefits, such as direct and indirect employment, other economic activity, and tax revenues. For example, bioenergy EPAs typically result in broad economic benefits because they also benefit the forestry and transportation sectors, in addition to the benefits associated with construction and operation of the facility itself.

Category 1: Deferring, Downsizing or Terminating Pre-COD EPAs

In early 2013, BC Hydro reviewed the status of all EPAs that have not reached COD. A total of 52[6] EPAs were examined, representing about 8,200 GWh/year of contracted energy, or about 4,400 GWh/year of firm energy after adjustment for attrition. BC Hydro applied the following review process:

[6] By August 2, 2013 BC Hydro had only 46 pre-COD EPAs with two additional projects reaching COD and four EPAs being terminated (as described in this section).

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- Stage 1 – Determine whether each pre-COD EPA project has progressed to substantial construction or if significant First Nations, stakeholder or other implementation risks exist. Projects where significant construction has taken place were deemed unlikely candidates for deferral, downsizing or termination because of the high costs that would be involved. As a result, 32 pre-COD EPAs proceeded to the next stage of review. This group consisted of 18 projects where development had stalled and termination appeared possible. The remaining 14 EPAs were identified as potential candidates for deferral or downsizing.
- Stage 2 – Assess the potential benefits of EPA deferral, downsizing or termination by examining the impact on the PV commitment and the PV of energy savings. In addition, carry out further assessment of implementation risks and other considerations. Based on an assessment of the estimated impact of potential deferral, downsizing or termination, a comparison of current contractual commitments versus expected commitments after implementation was carried out. This analysis indicated that, if successful, these EPA actions could result in an incremental rate reduction of, on average, approximately 1 per cent in the period F2014 through F2022.

To date, BC Hydro has executed mutual agreements to terminate four EPAs, representing 147 MW in nameplate capacity and 980 GWh/year of contracted energy generation. Since completion of these projects was not 100 per cent certain prior to termination, the impact on the probability-weighted supply forecast as shown in the LRBs is less.

BC Hydro is in discussions with other IPPs where development of pre-COD EPA projects has stalled. Based on an assessment of the estimated impact of potential deferral, downsizing or termination, a comparison of current contractual commitments versus expected commitments after implementation was carried out. This analysis indicated that, if successful, these EPA actions could result in:

- A reduction of contracted energy by F2021 of roughly 1,800 GWh
- A reduction in attrition-adjusted forecast firm energy supply by F2021 of 160 GWh/year
- A reduction in the PV of contractual commitments for electricity supply of more than $1 billion
- An incremental rate reduction of, on average, approximately 1 per cent in the period F2014 through F2022

BC Hydro is negotiating agreements to defer COD for projects or to downsize projects where possible; and is declining developer requests for BC Hydro's consent to plant capacity increases unless ratepayer value can be achieved.[7] For example, value can be realized through a variety of mechanisms, such as deferral of commercial operations, capping overall purchase obligations or other contractual concessions. There may also be some limited opportunity to cost-effectively negotiate agreements to terminate certain EPAs where BC Hydro does not have termination rights, but where a termination agreement may result in benefit to both parties. In these cases, BC Hydro weighs a number of factors to determine the best course of action, including but not limited to: BC Hydro's contractual rights and obligations; the PV of the purchase commitment; the value of the energy purchased over the term of the EPA; potential impacts on First Nations and stakeholders; the likelihood that the project will proceed to commercial operations; and the potential cost of a termination agreement, if any.

Table 4-5 and Table 4-6 show the impact on expected energy and dependable capacity of the proposed changes from deferring, downsizing or terminating pre-COD EPAs (Category 1). These changes reflected in the updated LRBs for energy and capacity presented in Figure 4-3 and Figure 4-4 at the end this section.

[7] BC Hydro has discretion under its EPAs to consent or not consent to various requests. In some cases, BC Hydro discretion is absolute and in other cases, BC Hydro must not unreasonably withhold or delay its consent.

Table 4-5 Expected Energy from Pre-COD EPA Terminations and Deferrals, GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Expected Terminations	-166	-181	-209	-209	-209	-209	-209	-211	-209
Expected Deferrals[8]	-331	-76	53	53	53	53	53	53	53
Total	-497	-257	-156	-156	-156	-156	-156	-157	-156

Table 4-6 Expected Capacity from Pre-COD EPA Terminations and Deferrals, MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Expected Terminations	-7	-7	-11	-11	-11	-11	-11	-11	-11
Expected Deferrals	-18	0	3	3	3	3	3	3	3
Total	-25	-7	-8	-8	-8	-8	-8	-9	-8

Category 2: EPA Renewals

As EPAs expire for projects already in operation, BC Hydro is targeting renewal of the contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that these are existing projects where the IPP's initial capital investment has been fully or largely recovered over the initital term of the EPA, BC Hydro expects to be able to negotiate a lower energy price. In its EPA renewal negotiations, BC Hydro will consider the seller's opportunity cost, the electricity spot market, the cost of service for the seller's plant and other factors such as the attributes of the energy produced and other non-energy benefits.

Previously BC Hydro assumed that no existing bioenergy EPAs would be renewed upon expiry due to pricing and fuel supply risks, and that all other existing EPAs would be renewed for the remainder of the planning horizon. For planning purposes, BC Hydro now estimates that about 50 per cent of the bioenergy EPAs will be

8 In some cases it is expected that there will be additional contracted energy and capacity as part of EPA amendments or prior commitments.

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renewed, about 75 per cent of the small hydroelectric EPAs that are up for the renewal in the next five years will be renewed, and all remaining EPAs will be renewed. These changes are summed up in Table 4-7 and Table 4-8 and are reflected in the LRBs presented for energy and capacity in section 4.2.6.

The above changes for EPA renewals reflect updated planning assumptions used for this IRP. On an ongoing basis, IPP projects will continue to be individually assessed as EPAs come up for renewal. Refer to section 9.2.4 for additional detail.

The following tables show the impacts to energy and capacity of implementing the proposed changes to EPA renewals (Category 2) using the planning assumptions set out above.

Table 4-7 EPA Renewal Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous EPA Renewals[9]	1,205	1,297	1,298	1,298	1,298	1,298	3,468	4,316	5,086
Updated EPA Renewals	1,147	1,245	1,570	1,683	1,824	2,117	4,357	5,463	6,356
Difference	-58	-52	273	385	526	819	889	1,147	1,270

Table 4-8 EPA Renewal Capacity Differences (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous EPA Renewals	137	142	142	142	142	142	417	444	470
Updated EPA Renewals	133	146	177	202	214	256	539	603	640
Difference	-3	4	35	60	73	114	122	159	170

[9] For Table 4-7 to Table 4-10, the "previous" assumptions refer to the illustrative example, starting in the spring of 2013, used to generate a baseline for comparison.

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Category 3: New EPAs

BC Hydro will strive to acquire additional electricity supplies in a prudent and sustainable manner. BC Hydro will also continue to honour prior agreements to negotiate EPAs:

- BC Hydro is committed to the IBAs it has signed with First Nations, with some of those agreements involving consideration of EPAs for power generation projects. The values of about 170 GWh/year of firm energy and 25 MW of ELCC beginning in F2020 are set out in footnote 4 to Table 4-1.
- BC Hydro, under the B.C. Government direction, has made prior commitments to enter into negotiations for EPAs with certain parties as part of broader economic development opportunities and First Nations initiatives. However, since these negotiations are at an early stage, no such potential new EPAs are reflected in the LRBs in this IRP.
- The SOP is an exceptional category of acquisitions as it is a legislated requirement pursuant to subsections 15(2) and 15(3) of the *CEA* which provide that BC Hydro may establish the terms and conditions of the offers under the SOP. The SOP was launched in April 2008 with original pricing of between about $75/MWh and $88/MWh depending on the region. In early 2011, BC Hydro increased the SOP pricing based on the Clean Power Call results. The price offered is roughly $100/MWh but varies depending on the region (the range is $95/MWh to $104/MWh). BC Hydro also increased the size eligibility from 10 MW to 15 MW of nameplate capacity. In March 2013, BC Hydro made changes to the SOP Rules that among other things limit multiple clustered projects from a single developer that exceeds 15 MW to enable broader participation; and create added flexibility for BC Hydro to better manage when SOP energy supply comes on-line. BC Hydro reviews the SOP every two years, with the next review slated for 2014.

- At the B.C. Minister of Energy and Mine's request and based on feedback from First Nations, BC Hydro revised its August 2, 2013 IRP to reflect additional support for the clean energy sector in B.C. and to further promote clean energy opportunities for First Nations communities. Among other things this resulted in an increase to the SOP annual target from 50 GWh/year to 150 GWh/year to enable more small-scale projects in communities throughout BC Hydro's service area and initiatives to promote First Nations participation in the clean energy sector; refer to section 9.2.10 for more detail.

The changes between the illustrative example and what is proposed in this IRP for the SOP are summarized in Table 4-9 and Table 4-10 and are reflected in the LRBs presented in section 4.2.6. As of August 2, 2013, pursuant to the SOP BC Hydro has awarded 11 EPAs with most of the resources being run-of-river, with 12 applications currently under review. The SOP has delivered a total of 407 GWh/year between 2009 and the end of July 2013 as follows: 2009 – 3 GWh/year; 2010 – 41 GWh/year; 2011 – 62 GWh/year; 2012 – 163 GWh/year; and 2013 – 105 GWh/year. For planning purposes BC Hydro, in using its professional judgment based on historical performance of the SOP to date and the 2013 changes to the SOP such as the "cluster rule" change, has included 70 per cent of the new SOP target of 150 GWh/year in its LRB estimates.

Table 4-9 New SOP EPA Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous SOP	520	520	520	520	520	520	520	520	520
Updated SOP	159	239	318	398	477	557	636	1,034	1,431
Difference	-361	-281	-202	-122	-43	37	116	514	911

Table 4-10 New SOP EPA Capacity Differences (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous SOP	29	29	29	29	29	29	29	29	29
Updated SOP	13	19	25	32	38	44	51	82	114
Difference	-16	-10	-4	3	9	15	21	53	85

4.2.5.2 Delay Planned Ramp-ups in Spending on DSM Activities

Chapter 6 examines three long-term DSM options, Option 1, Option 2/DSM Target and Option 3, as described in section 3.3.1. Section 6.3 addresses the question of whether DSM Option 2/DSM Target should be revised in the long-term.

This section considers alternative means (the various ways) to reduce DSM costs in the short-term while maintaining the ability to achieve the longer-term DSM savings targets examined in Chapter 6. However, as shown in Table 4-11 below, the LRB after: (1) the EPA management activities in section 4.2.5.1; (2) short-term reductions to the three DSM options discussed in section 3.3.1 and further explored in this section; and (3) the VVO reductions in section 4.2.5.3, still result in surplus in the short to mid-term.

Table 4-11 Energy Surplus/Deficit with DSM Options, GWh

	F2014	F2015	F2016	F2017	F2018	F2019	F2020
DSM Option 1	1,100	2,464	2,331	4,884	3,501	2,154	1,364
DSM Option 2/DSM Target	1,119	2,533	2,480	5,147	3,884	3,040	2,631
DSM Option 3	1,142	2,665	2,813	5,707	4,693	3,701	3,245

DSM is a flexible resource in the context of optimizing BC Hydro's activities over the short to mid-term. To some degree, DSM activity can be ramped up or down over time to better match demand. However, DSM activities are enabled by long-term, sustained relationships with customers and industry partners, and some opportunities are time-limited and may not be deferrable. It is important to understand the limits to which DSM savings can be ramped down (to achieve short-term savings) and then ramped back up to achieve long-term DSM targets.

For DSM Option 3, the ability to reduce current expenditure levels was considered but dismissed. Option 3 features increased program activities and expenditures to target the greatest level of DSM program savings currently considered deliverable. It is BC Hydro's professional judgement that to reduce near-term expenditures but continue to rely upon the longer term savings is not believable or prudent in the case of DSM Option 3.

For Option 1 and Option 2/DSM Target, assessments were also undertaken on near-term expenditure reductions and the ability to recover to the long-term savings targets. For both of these DSM options, the alternative means to achieve long-term DSM targets would reduce ramp rates. The following sets out the alternative means of achieving the Option 2/DSM Target:

- **Alternative Means 1:** continue with previously planned expenditures to implement the DSM target. This is a 'status quo' option, with no adjustments to program expenditures in the near term.
- **Alternative Means 2:** adjust program and supporting initiative expenditures in the near term and then moderately ramp up to the DSM target by F2021. By F2022, expenditures are reduced by over $330 million relative to Alternative Means 1. The reduction is focused over the near term (F2015 to F2022), where F2014 is a transition year. In F2016, planned expenditures are adjusted to a base level of $125 million.

A third path to reach the DSM target was also considered, which reduces expenditures further in the near-term (down to $100 million in expenditures in F2016, the same level of near-term DSM program activity as DSM Option 1 described in Chapter 3) and aggressively ramps up to higher levels of activity starting in F2017. However, even with the aggressive ramp-up rate, this path fails to return to DSM target levels by F2021. In addition, there are likely additional energy savings delivery risks associated with further carve out of expenditures and the aggressive ramp-up rate. For these reasons, BC Hydro does not consider this path to be a viable alternative to return to the current DSM target by F2021.

In examining the alternatives, BC Hydro considered a range of inputs and decision criteria. In working with its Energy Conservation and Efficiency Committee, BC Hydro formed these inputs and criteria into a framework and then condensed them to a reduced set of comparators:[10]

- **Rate Impact:** the rate impact relative to the DSM plan baseline over the near and long-term
- **Cost-Effectiveness:** relative to BC Hydro's avoided cost, program and portfolio cost-effectiveness is considered from both a Total Resource Cost (**TRC**) and Utility Cost (**UC**) perspective. The TRC and UC cost-effectiveness tests are described in section 3.3.4.1.
- **Bill Reductions:** the change to BC Hydro's revenue requirements (or aggregate customer bill) resulting from the different DSM options
- **Risk/Flexibility:** the risk and consequence (regret) of not being able to recover to higher levels of DSM activity by certain time periods; this is managed by maintaining the flexibility to ramp up to higher levels of DSM at points of time in the future

As the impacts considered were based on higher level estimates generated for planning purposes, the analysis will need to be further refined. However, some directional conclusions are:

[10] Other important attributes that were considered include: lost opportunities, customer fairness / equity, customer and industry relationships, market transformation, economic development and environmental impact. While these were not used as comparators, they were considered either (1) implicitly in the design of the alternative means, (2) as a sub-component of one of the comparators (e.g., lost opportunities, customer fairness / equity and customer and industry relationships affect the ability to ramp back up and therefore relate to risk / flexibility) or (3) as something to describe or report out on, but not actively used to tradeoff between means.

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- Over the near term, lower level of expenditures are expected to have a reduced rate impact
- Over the long-term, a negligible difference between the average rate impacts of the different alternative means is expected
- A negligible impact on bill reductions from Alternative Means 1 to Alternative Means 2 over 20 years is expected
- Moving from Alternative Means 1 to Alternative Means 2 may introduce some additional, yet-to-be-quantified, deliverability uncertainty because the reduction in near-term activities may have some effect on the ability to ramp back up

As part of the plan to reduce portfolio costs, BC Hydro recommends Alternative Means 2 as the preferred path to reach the DSM target of 7,800 GWh by F2021 and by doing so, reduce expenditures in the near term by approximately $330 million.

The rationale for this recommendation is as follows:

- Moving from Alternative Means 1 to Alternative Means 2 provides roughly the same bill reduction benefit over 20 years
- Moving from Alternative Means 1 to Alternative Means 2 lowers rate impacts in the near-term by reducing expenditures by approximately $330 million

While Alternative Means 2 may have more deliverability uncertainty than Alternative Means 1, BC Hydro considers the trade-off between rate impact and deliverability risk to be acceptable. Moreover, the risk of energy savings delivery is mitigated in part through the construction of Alternative Means 2, which was designed to limit the risk of not being able to ramp up to the DSM target.

Table 4-12 and Table 4-13 demonstrate the impacts on energy and capacity of adopting Alternative Means 2 early in the planning horizon. As this table shows, this reduces savings in the near term but DSM savings return to the Option 2/DSM Target levels by F2021.

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Table 4-12 DSM Plan Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Alternative Means 1 Option 2/ DSM Target	5,127	5,689	6,474	7,193	7,790	8,202	8,423	10,196	10,995
Alternative Means 2 Option 2/ DSM Target (recommended)	4,364	4,942	5,893	6,842	7,790	8,202	8,423	10,196	10,995
Change in DSM	-763	-747	-582	-352	0	0	0	0	0

Table 4-13 DSM Plan Capacity Differences[11] (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Alternative Means 1 Option 2/ DSM Target	781	940	1,090	1,238	1,371	1,460	1,519	1,873	2,074
Alternative Means 2 Option 2/ DSM Target (recommended)	820	932	1,078	1,224	1,371	1,460	1,519	1,873	2,074
Change in DSM	39	-8	-12	-14	0	0	0	0	0

Similarly, BC Hydro concluded that it could reduce short-term expenditures if it were to implement DSM Option 1 while maintaining the longer term *CEA* 66 per cent target in F2021. With the lower DSM Option 1 savings target, there was not as much room to move.

In conclusion, Alternative Means 2 is the recommended approach to achieving Option 2/DSM Target. Chapter 6 utilizes the preferred means of achieving the three DSM options and provides comparisons among maintaining, increasing or decreasing long-term levels of DSM savings and how these resource options compare against other supply-side resources available.

[11] The Option 2/DSM Target does not appear to have the same relative reductions for the peak capacity savings when compared to the original 2008 LTAP target because the DSM plan has had recent updates to the mix of programs, rates and codes which impacts the associated capacity savings.

4.2.5.3 Scale Back Voltage and Var Optimization Project Implementation

VVO technology helps reduce the amount of electricity that must be transmitted to ensure sufficient power quality at customer sites. BC Hydro's VVO program was developed in October 2011 based on long-term energy requirements and a LRMC of $132/MWh ($F2012) based on the Clean Power Call.

A review of the VVO program elements identified that a portion of those energy savings are no longer cost-effective. BC Hydro is recommending that work will be completed as planned for substation VVO projects that are presently being implemented. On a go-forward basis, substation VVO projects will be considered based on system growth, reliability, safety and sustainment requirements, and an updated LRMC revised through this IRP (see section 9.2.12). Table 4-14 and Table 4-15 show that this results in a reduction of estimated VVO savings of about 90 GWh/year and 1 MW in F2017, growing to about 250 GWh/year and 1 MW in F2022.

Table 4-14 VVO Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Original VVO Program	359	418	496	539	562	576	585	589	594
Updated VVO Program	273	288	304	314	326	328	329	338	346
Change in VVO	-86	-129	-193	-225	-235	-248	-256	-252	-248

Table 4-15 VVO Capacity Differences (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Original VVO Program	1	1	1	1	1	1	1	1	1
Updated VVO Program	0	0	0	0	0	0	0	0	0
Change in VVO	-1	-1	-1	-1	-1	-1	-1	-1	-1

4.2.5.4 *Customer Incentive Mechanisms*

Another method identified to temporarily increase demand is through specific, temporary and tailored incentives to BC Hydro's large customers (referred to as Customers Incentive Mechanisms). To date, BC Hydro focused on identifying potential incremental loads from existing Transmission Service Rate[12] (**TSR**) customers, which is approximately 300 GWh/year. Examples of incremental load categories for existing customers include: installing new operating lines; restarting existing operating lines or restarting shutdown plants; increased utilization of existing production capacity (load factor, shifting); shift to production of energy-intensive, higher value products. Going forward, BC Hydro will identify potential new customer loads. One example of potential new customer loads is commercial enterprises operating container and cruise ship terminals which are contemplating investments in shore-side electrical service.[13]

There are a limited number of examples of incentive mechanisms to increase demand: (1) B.C.'s Power for Jobs program launched in 1998, (2) Ontario's Industrial Electricity Incentive Program announced on June 12, 2012; (3) a Hydro Quebec rate schedule introduced in 1983 but phased out in 1988; and (3) Manitoba Hydro's Surplus Energy Program that gives customers access to surplus energy at the same price Manitoba Hydro would receive from the export market.

The B.C. Power for Jobs program was enabled by legislation – the *Power for Jobs Development Act*[14] – in 1997. This program was developed to stimulate economic development in B.C. by making a limited amount of discounted power available to new or expanding businesses, 200 MW of power was notionally allocated to the program from the Canadian Entitlement under the Columbia River Treaty. This

[12] Applying to BC Hydro's largest industrial customers.

[13] BC Hydro has an existing Shore Power Rate (Tariff Supplement No. 76) but the rate is exclusive to cruise ships at Canada Place. BC Hydro estimates that about 60 MW of shore power could be served in the next two to three years, and another 80 MW could be served in the next three to 10 years.

[14] S.B.C. 1997, c.51.

power was made available to qualifying companies on the same terms and conditions as BC Hydro's regular electric tariffs except for the price which the B.C. Government directed BC Hydro to provide at a discount. The program lasted several years and had a number of active participants but the program never achieved its objective of stimulating economic development in a material way. The principal reason for this is that the qualifying criteria were too onerous and screened out most of the potential candidates. However, the criteria were necessarily onerous to address some of the key design considerations, as set out below:

- **Eligibility:** Should be broad so that all TSR customers have an opportunity to participate, perhaps by sector due to intra-industry competition concerns. Commercial customers could also be eligible
- **Duration:** A shorter term may be appropriate because if the mechanism is extended this may advance the need for new higher-cost energy resources
- **Pricing:** For illustrative purposes, pricing could be set between spot market projections for the years F2013 – F2018 (a 'BC sell price'[15] of about $20/MWh for F2013 (in $F2013, USD) to $23/MWh for F2018 (in $F2013, USD) for light load hours) and industrial/commercial customer Tier 1 pricing (for example, about $37/MWh for F2013 (in $F2013) blended, energy portion only of Rate Schedule 1827 for TSR customers).[16] The significant market price differentials between freshet and winter pricing would be considered in the mechanism.

A final consideration would be to look at whether there is alignment with the need to conserve due to the longer-term energy and capacity LRB deficits set out in section 4.2.6.

[15] The 'BC sell price' is the Mid-C market electricity price less wheeling and losses from the B.C. border to Mid-C.

[16] The highest 'Tier 1' pricing is Residential Inclining Block rate at $69/MWh for up to 1,350 kilowatt hours bi-monthly ($F2013).

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Using Customer Incentive Mechanisms to temporarily increase demand comes with risks:

- Favourable agreements that are "temporary" in nature can have a tendency to become entrenched and difficult to withdraw when they are no longer required. BC Hydro's E-Plus rates are an example
- There may be conflict between the need to conserve due to the longer-term energy and capacity LRB deficits and the financial benefits of temporarily increasing demand

While BC Hydro is recommending that the incentive mechanisms over the short to mid term be explored, no changes to forecasted demand will be made at this time.

4.2.6 Short-Term Energy Supply Management: Summary and Conclusions

The following tables show the cumulative impact of implementing all proposed changes to energy and capacity over the planning horizon discussed in section 4.2.

Table 4-16 Cumulative Changes to Incremental Resource Additions, Energy (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
EPA Terminations and Deferrals	-497	-257	-156	-156	-156	-156	-156	-157	-156
EPA Renewals	-58	-52	273	385	526	819	889	1,147	1,270
New EPAs (SOP)	-361	-281	-202	-122	-43	37	116	514	911
DSM	-763	-747	-582	-352	0	0	0	0	0
VVO	-86	-129	-193	-225	-235	-248	-256	-252	-248
Net Change	-1,766	-1,467	-860	-470	92	452	594	1,252	1,775

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Table 4-17 Cumulative Changes to Incremental Resource Additions, Capacity (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
EPA Terminations and Deferrals	-25	-7	-8	-8	-8	-8	-8	-9	-8
EPA Renewals	-3	4	35	60	73	114	122	159	170
New EPAs (SOP)	-16	-10	-4	3	9	15	21	53	85
Change in Planning Reserves	6	2	-3	-8	-10	-17	-19	-28	-34
DSM	39	-8	-12	-14	0	0	0	0	0
VVO	-1	-1	-1	-1	-1	-1	-1	-1	-1
Net Change	0	-20	7	32	62	103	116	174	211

Figure 4-3 and Table 4-18, and Figure 4-4 and Table 4-19, show a need for energy and capacity emerges in F2027 and F2021 respectively with no LNG load, and in F2022 and F2020 respectively when including Expected LNG load.

Figure 4-3 Energy Surplus/Deficit with Incremental Resources

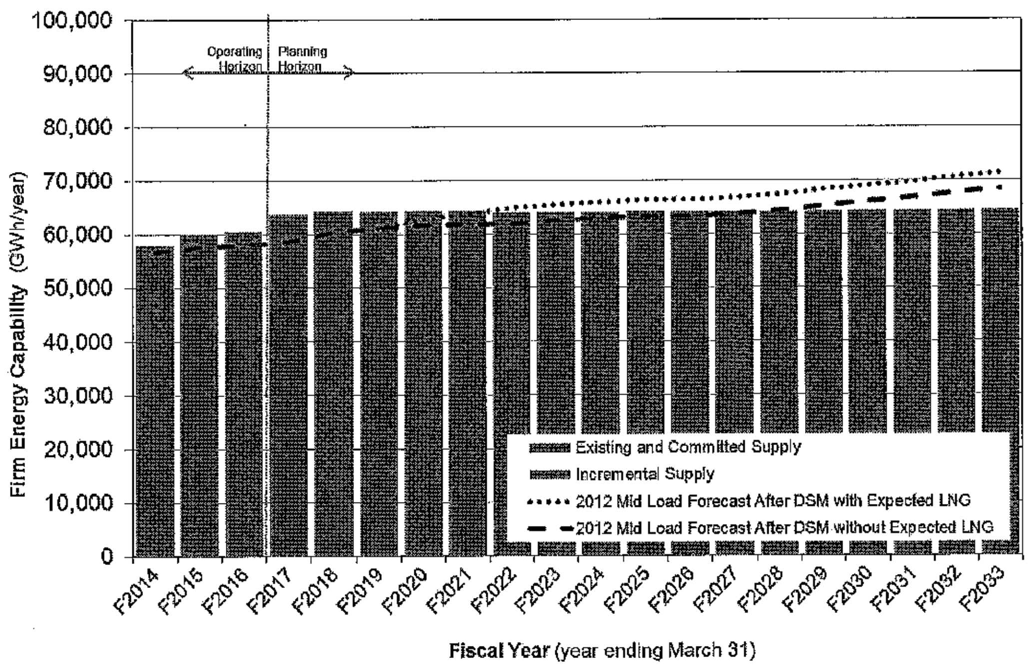
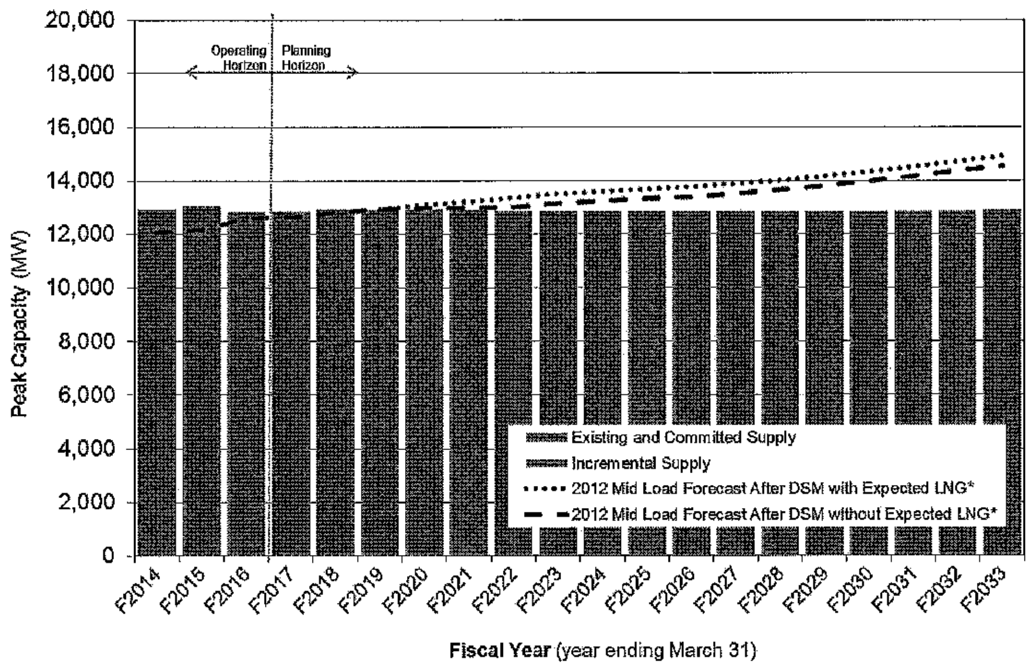


Table 4-18 Energy Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	5,147	3,884	3,040	1,631	497	-845	-1,462	-3,175	-6,932
Surplus/Deficit with Incremental Resources without Expected LNG	5,147	3,884	3,040	2,631	2,497	2,155	1,538	-175	-3,932

Figure 4-4 Capacity Surplus/Deficit with Incremental Resources



* Including planning reserve requirements

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Table 4-19 Capacity Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	239	115	-8	-181	-322	-505	-647	-1,147	-2,026
Surplus/Deficit with Incremental Resources without Expected LNG	239	115	-8	-61	-82	-145	-286	-787	-1,665

Prior to the emergence of these energy and capacity gaps, BC Hydro has sufficient existing, committed and incremental resources (e.g., if the DSM target and EPA renewals are implemented) to achieve self-sufficiency and so will continue to examine ways of optimizing its portfolio of energy resources over this timeframe. Chapter 9 summarizes the Recommended Actions outlined in this section and provides more details regarding how BC Hydro will continue to act on these issues.

The remainder of Chapter 4 describes the framework for addressing these long-term resource options. Chapter 5 examines the conditions that influence prices as BC Hydro interacts with external energy markets. Chapter 6 presents analysis and conclusions regarding these long-term resourcing issues.

4.3 Long-Term Resource Planning Analysis Framework

Section 4.2.6 shows a need for energy and capacity in F2028 (the one-year move from F2027 set out in the August 2, 2013 IRP to F2028 results from the increased SOP annual target) and F2019 (based on adjustments concerning the John Hart Generating Station Replacement Project described in section 2.3.1) respectively based on BC Hydro's mid-2012 Load Forecast before Expected LNG, and a need for energy and capacity in F2022 and F2019 respectively with Expected LNG. This section explains the planning analysis used to compare long-term resource options. Analysis proceeded through the following steps:

1. Consider long-term resource planning questions

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2. Define the main decision objectives used to design and compare long-term resource options
3. Assess key uncertainties regarding these resource options
4. Establish portfolio analysis methodology and assumptions

4.3.1 Key Long-Term Resource Planning Questions

The key questions to determine the best mix of supply and demand resources are as follows:

(a) **Natural Gas-Fired Generation:** What is the optimal use of natural gas-fired generation within the *CEA*'s 93 per cent clean or renewable energy objective? And how might natural gas-fired generation be used to serve LNG loads?

(b) **DSM Target:** Should BC Hydro's current long-term DSM target be adjusted?

(c) **Site C Project:** Should BC Hydro continue to advance Site C for its earliest ISD?

(d) **Serving LNG and North Coast Loads:** What actions are required and what supply options need to be maintained to ensure that BC Hydro is able to supply Expected LNG load, additional LNG load above expected and other loads in the North Coast while considering the specific planning challenges of this region?

(e) **Fort Nelson/Horn River Basin:** What is BC Hydro's strategy for meeting significant and uncertain load growth in the combined Fort Nelson and Horn River Basin regions, while ensuring load growth in Fort Nelson is met? What approach should BC Hydro take to respond to *CEA*'s subsection 2(h) energy objective to "encourage the switching from one kind of energy source or use to another that decreases [GHG] emissions in" B.C. via enabling electrification in this region?

(f) **General Electrification:** What role should BC Hydro play to support provincial climate policy? What is BC Hydro's strategy to get ready for potential load

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driven by general electrification, including assessing potentially significant impacts to existing ratepayers?

(g) **Transmission:** What transmission needs are foreseen over the long-term planning horizon and what actions need to be taken? And to what degree should BC Hydro take a more proactive approach to building transmission infrastructure for clusters of generation locations in advance of need?

(h) **Capacity Requirements and Contingency Considerations:** What additional capacity requirements are foreseen, and what strategies and actions are appropriate in response to these future needs? In addition to filling the most likely mid gap, what are some events that might make the gap larger or smaller, what is the magnitude and timing of these events and what actions can BC Hydro prepare as contingency plans?

4.3.2 Comparing Alternatives Using Multiple Planning Objectives

For any of the key long-term planning questions highlighted in the previous section, a number of possible solutions may be viable. <u>Table 4-20</u> lays out the decision objectives by which potential solutions are compared and provides the rationale for their consideration. Many of these considerations are embodied in the *CEA* section 2 British Columbia's energy objectives, such as greenhouse gas (**GHG**) emission reduction targets, ratepayer (financial) impacts, and economic development. There is clearly an overlap between these decision objectives and the ones considered for the short-term analysis, with the exception of 'Environmental Footprint', which is more relevant as resources are being added to meet increased demand.

The following sections describe how the financial, environmental and economic development decision objectives were considered in the context of long-term resource planning; minimizing DSM deliverability risk is addressed in detail in section <u>4.3.4.2.</u>

Table 4-20 *CEA* and Other Resource Planning Decision Objectives

Decision Objective	Reason for Inclusion
Minimize Financial Impacts, including: • Cost (various measures) • Cost Uncertainty • Differential Rate Impacts	Good utility practice; First Nations, public and stakeholder interests; align with *CEA* 'ratepayer impact' objectives grouped in Table 1-1
Minimize Environmental Footprint, including: • Land Footprint • Water Footprint • Criteria Air Contaminants • GHG Emissions	Good utility practice; First Nations, public and stakeholder interests; align with *CEA* 'clean/renewable/DSM/GHG impacts' objectives grouped in Table 1-1.
Maximize Economic Development	First Nations, public and stakeholder interests; align with *CEA* 'economic development' objectives grouped in Table 1-1
Maximize System Reliability • Minimize DSM Deliverability Risk	Good utility practice; First Nations, public and stakeholder interests

4.3.2.1 Financial Impacts

In the IRP, the financial implications of the resource options, or strategies, to fill the LRB gap are tracked at a portfolio level both for the cost of acquiring new resources and also for how these resources interact with the existing BC Hydro system and the external electricity market. Costs are expressed on a PV basis to capture the impact of the timing of costs and trade revenues over the planning horizon. Where uncertainty is relevant, cost ranges or costs across scenarios are highlighted.

4.3.2.2 Environmental Footprint

The environmental footprint of portfolios modelled to meet long-term energy and capacity needs are tracked with respect to potential effects on land, freshwater, marine, air (criteria air contaminants) and climate change (GHG emissions). These footprints were considered at a portfolio level as data does not exist at a regional or local level for all projects; in many cases, generation resources are represented as a "typical" project or bundle of projects. In addition, the resources selected through modelling are not necessarily the ones that would be selected through an actual power acquisition process.

The full set of environmental information for comparing portfolios with respect to the key IRP questions is presented in Appendix 6A. This information is summarized at a level appropriate for comparing portfolios of resource options in section 6.4.

4.3.2.3 Economic Development Impact

In response to the *CEA*'s subsection 2(k) energy objective "to encourage economic development and the creation and retention of jobs", BC Hydro tracks the possible footprint of each portfolio for meeting long-term energy and capacity needs with respect to effects on employment, Gross Domestic Product (**GDP**) and government revenue. These measures are generated for a provincial-level view, as the data and modelling did not exist to provide a more regional view of these potential impacts. In addition, given that the modelled resource additions might not be the same as the projects selected through an actual acquisition process, these measures are appropriate for high-level comparisons of broad impacts.

Appendix 3A-5 discusses the methodology behind these measures and provides the detailed economic development criteria, including more granular views of the source of these potential impacts (e.g., direct versus indirect/induced changes). As this additional level of analysis did not provide additional insight into the comparison of portfolios of resource options it is presented at a higher level in the body of the IRP.

BC Hydro notes that rate impacts can also be an economic development issue.

4.3.2.4 IRP Treatment of Multiple Decision Objectives

In instances where the impacts of different options are quantified with respect to how they impact decision objectives, a consequence table is a useful format in which to present these multiple effects. A consequence table is a collection of alternatives, decision objectives and their estimated attributes arranged in a matrix with the alternatives displayed as column headers (i.e., portfolios representing different strategies for addressing the LRB), and the relevant decision objectives displayed as row labels. An example similar to a consequence table from Chapter 6 is presented in Table 4-21 for illustrative purposes.

Table 4-21 Example Consequence Table

	Measure	Clean with SCGTs (within *CEA* 93% limit)	Clean Power with Transmission
Land	total hectares (**ha**)	22,300	28,200
Marine (valued ecological features)	total ha	49	56
Affected Stream Length	km	390	510
GHG Emissions	CO_2e ('000 t)	16,400	3,800
Local Air Contaminants	Oxides of Nitrogen ('000 t)	17	12
Local Air Contaminants	Carbon Monoxide ('000 t)	33	12
GDP	$ million PV	16,000	16,200
Employment	FTEs	317,000	338,100
Government Revenues	$ million PV	2,600	2,700
Cost	$ million PV	14,948	15,603

While judgment is required to reduce the full analysis to a condensed level, this view allows a reader to see the relative impacts of resource options across alternatives and decision objectives. (The unabridged versions of these tables can be found in Appendix 6A).

Consequence tables also help clarify the balance BC Hydro is seeking in developing cost-effective solutions. Given the precision of the measures and the range of their potential impacts across resource options for each IRP question, it cannot be presented as a mechanical weighting and scoring outcome. Rather the consequence tables attempt to summarize what could be gained and what might be given up across resource options. Qualitative factors not captured in the consequence tables and comparisons where impacts are not easily quantified also need to be considered; professional judgment is required to balance the quantified and non-quantified factors across these multiple options and multiple objectives when developing conclusions and recommendations.

4.3.3 Key Uncertainties and Risks

To provide a clear discussion of the uncertainties and risks that BC Hydro is managing, the following definitions are provided:

- Uncertainties are variables with unknown outcomes
- Risk is commonly defined as the effect of uncertainty on objectives

Some key uncertainties and related risks for addressing resource needs over the longer term include:

(a) Load growth and the chance that load growth exceeds or falls below expectations

(b) DSM initiatives and the chance that DSM savings exceed or fall below expectations

(c) Features of BC Hydro's existing system and its operations, including inflow water variability

(d) Natural gas and electricity spot market and long-term market price uncertainty

(e) Renewable Energy Credit (**REC**) prices and GHG emission prices

(f) Current and future regulatory and public policy developments such as: GHG regulation, Renewable Portfolio Standard targets and eligibility requirements

(g) IPP development, including type of resource and location and the risk that these resources require significant capacity and transmission support

(h) IPP attrition rates from power acquisition processes and the chance that these exceed or fall below expectations

(i) Site C timing and approval to proceed to construction

(j) Natural gas-fired generation resources and the uncertainty around the ability to permit these resources in time to respond to short-term capacity requirements

(k) New demand for electricity may develop sooner than transmission lines can be built to provide the service

(l) Non-thermal capacity resources and their ability to meet capacity requirements on short notice with high reliability

4.3.4 Quantifying Uncertainty

Section 4.3.3 laid out key uncertainties and risks that could potentially influence the comparison of resource options with respect to the IRP's key questions. Where possible, BC Hydro quantified these uncertainties to be transparent about their role in the IRP analysis, results and conclusions. This section describes the different approaches to handling uncertainty in the IRP analysis. These approaches are addressed in more detail in Appendix 4A.

Table 4-22 Approaches to Handling Uncertainty

Approach	Brief Description	Examples
Parameterization of Historical Observations	Uses sequences of past data to derive a statistical description of the range of uncertainty	Load forecast inputs, such as economic growth, housing starts, population growth
Subjective Probability Elicitation	Where good historical data does not exist, uses knowledgeable specialists to construct a description of the range of uncertainty	• Savings from DSM tools including codes and standards, rate structures and programs • IPP attrition rates for possible future calls
Monte Carlo Analysis	Mechanical way to jointly calculate the influence of several uncertain variables through simulation of thousands of combinations	• Load forecasting • DSM savings (bottom-up analysis)
Scenario Analysis	An alternative way to jointly calculate the influence of several uncertain variables, but only using a few, select combinations	• Market price scenarios • Load/resource gap (large and small gap)

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Approach	Brief Description	Examples
Sensitivity Analysis	Testing one variable at a time to see whether different values within the range of uncertainty impact policy considerations	In addition to the scenarios described above, exceedance of the Site C capital cost estimate; narrowing the cost of capital differential between BC Hydro and IPPs; higher and lower wind integration cost. BC Hydro also undertook compound sensitivities such as low gap, low market
Conservative Point Estimates / Managed Costs	Incorporates uncertainty by taking a single point estimate, chosen in a "conservative" fashion	Firm energy expected from IPP hydro projects
Best Estimates	Does not take into account uncertainty in any fashion; usually reserved for variables where uncertainty is assumed to have a small or manageable impact	Energy from wind projects

The IRP analysis uses a mix of these approaches to explore how uncertainty impacts the comparison of options and the strategies to manage the residual risks of the Recommended Actions. As always, professional judgment informed by quantitative analysis and qualitative information is required when interpreting data, balancing objectives, and making decisions.

4.3.4.1 Load Forecast Uncertainty

The uncertainty around the load forecast is one of the largest uncertainties faced by BC Hydro in its long-term planning process. As outlined in section 2.2.4, BC Hydro produces both a mid-load forecast as well as a range of uncertainty around that estimate. This range of uncertainty is derived using a Monte Carlo analysis based on the impact on load of the uncertainty associated with a set of key drivers:

- The drivers for the commercial and residential sectors include economic activity, weather, electricity rates and demand elasticity
- The spread of uncertainty around the large transmission sector was approached separately. Given the large volume of transmission level demand that could increase or drop off in response to rapidly changing external market forces, the load forecast Monte Carlo model was augmented to better capture

this important influence on load uncertainty. The transmission sector was broken down into four major sub-components: Forestry, Oil and Gas, Mining, and Other. For each sector, BC Hydro produced a range of possible load levels to capture both very high load and very low load growth trajectories. For each sector, these trajectories were put into a triangular probability distribution (see Table A2.2 in Appendix 2A). To capture the notion that these sectors likely depart from their mid forecasts in response to common external shocks, these growth trajectories were modelled with a positive correlation. Finally, the Monte Carlo model also employed a slight positive correlation between these sectors and the overall GDP to capture the common movements of the resource sector and the economy in general.

The results of the Monte Carlo simulation are then split into three discrete forecasts: high forecast, mid forecast and low forecast. By construction, the high and low forecasts (shown here as the edges of the fan of uncertainty) are the mean of the upper and lower twentieth percent tails of the load forecast distribution. As the results turn out, the blue shaded area is also approximately the 80 per cent confidence interval for the load forecast.

Figure 4-5 Range of Uncertainty Regarding Energy Load Forecast

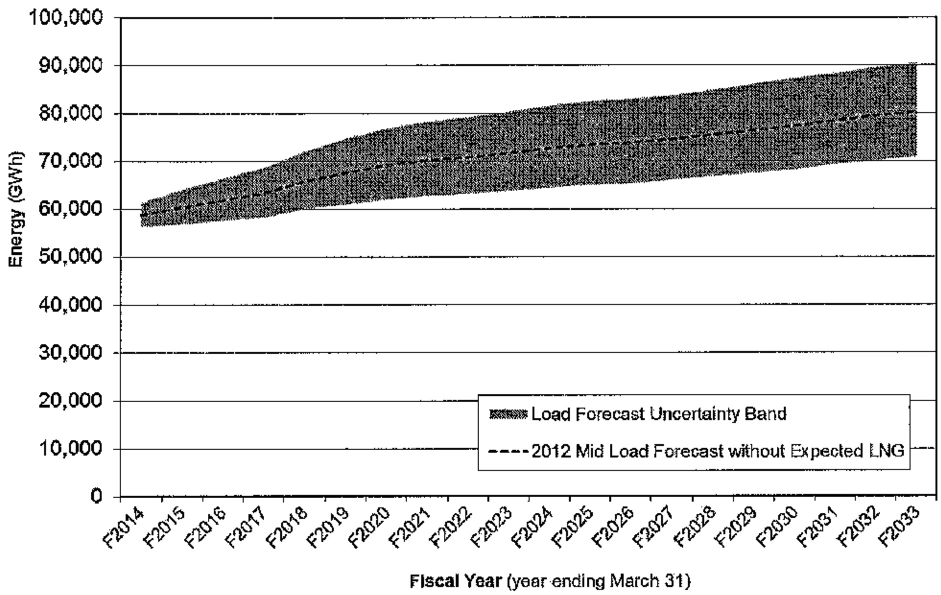
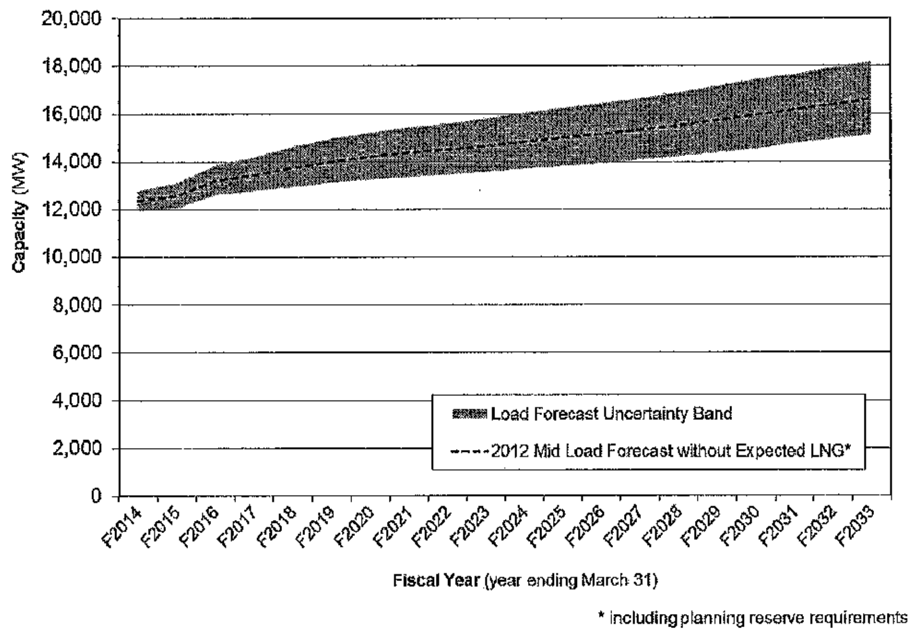


Figure 4-6 Range of Uncertainty Regarding Capacity Load Forecast



Several key uncertainties are captured through separate analyses due to their large size and uncertain timing:

- Potential North Coast LNG loads
- Potential Fort Nelson and Horn River Basin loads
- Potential general electrification loads

These potentially large, discrete additions to load are covered as separate topics of analysis within the IRP.

As discussed in section 2.2.4, and in response to the BCUC 2008 LTAP Directive 6, BC Hydro investigated the overlap and interrelationship between load growth and DSM savings (referred to as DSM/Load Forecast Integration). Details of this can be found in Appendix 2B of the IRP, however not all issues have been resolved. Some gaps still remain to be addressed, including natural conservation and natural load growth assumptions for the 2012 Load Forecast and baseline assumptions for DSM programs. These still have the potential to impact load forecasting accuracy.

4.3.4.2 DSM Savings Uncertainty

DSM continues to be BC Hydro's first and best option for meeting load growth. However, precise forecasting of DSM savings for long-term planning purposes is challenging for several reasons, including:

- Limited experience with respect to targeting cumulative savings above current levels
- Difficulty in distinguishing between load growth and DSM effects
- Difficulty linking customer response to DSM actions, and forecasting the timing and efficacy of regulatory changes

In view of these challenges, BC Hydro continues to emphasize and build upon approaches described in the 2008 LTAP to understand DSM savings uncertainty.

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Part of these approaches characterizes the range of uncertainty around DSM savings estimates to better inform decisions regarding energy and capacity planning. In addition, where possible and available, BC Hydro looked at what other jurisdictions have done on this subject and finds that it is among the leaders in the field in its efforts at assessing DSM uncertainty in the long-term planning context.

BC Hydro is filling the majority of its load/resource gap with DSM, so understanding the range of uncertainty around savings estimates is crucial. Forecasting DSM savings uncertainty is a new field that draws extensively upon unique techniques such as subjective probability judgments. As such, substantial, additional details are provided in Appendix 4B on the methodology and detailed findings. The discussion of DSM savings uncertainty is organized around the following steps:

- Jurisdictional Review Summary
- Quantified Uncertainty Regarding DSM Energy Savings
- Quantified Uncertainty Regarding DSM Energy-Related Capacity Savings
- Capacity-Focused DSM Savings Uncertainty
- Overall Conclusions

DSM Jurisdictional Review

The key driver behind the DSM uncertainty assessments was to better understand the degree to which BC Hydro could deliver on its DSM targets. While the bulk of this work was based on internal analysis, BC Hydro also looked externally to determine the extent to which other jurisdictions have been able to deliver on similar DSM goals. The resultant DSM jurisdictional assessment can be found in Appendix 4D; its application to DSM uncertainty can be found in Appendix 4B. This section highlights key findings and draws lessons for DSM uncertainty assessment.

The study looked at 26 utilities and DSM implementers in North America. To a certain extent, results are limited by reporting issues and data availability. This

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sample comprises a snapshot of the leading and most aggressive applications of DSM in the North American electricity sector, and is most useful for comparing changes to program spending and less useful for changes to codes and standards and rate design. At a high level, this is because few jurisdictions report energy savings from codes and standards activity and because other jurisdictions focus on peak shaving rate structures such as Critical Peak Pricing.

Using the average annual savings goals for DSM Option 2/DSM Target and comparing this to what has been claimed by other utilities, the following observations can be made:

- The study is partially based on claimed savings from other jurisdictions. However, this does not reduce the difficulty of distinguishing between DSM effects and impacts on load growth. Moreover, verification methods and reporting vary across jurisdictions. This means that those levels of savings claimed in other jurisdictions do not necessarily translate into potential to reduce BC Hydro load.
- No other jurisdiction in this survey is relying on a combination of programs, codes and standards, and rate design in a coordinated way. This makes an "apples to apples" comparison very difficult.
- If the future program targets for Option 2/DSM Target are examined alone, then there are jurisdictions that have claimed past savings in excess of BC Hydro's planned savings from DSM programs
- At least one other jurisdiction in this sample (PacifiCorp) plans on using less than the full amount of cost-effective DSM potential due to concerns regarding reduced portfolio diversification and deliverability risk, based on professional judgment

This jurisdictional assessment was designed to assist in understanding the confidence with which BC Hydro can deliver its planned DSM savings in future years. This gives some reasons for cautious optimism about moving forward with DSM programs at the level of DSM Option 2, but it also highlights the uniqueness of BC Hydro's combination of all three DSM tools to achieve conservation targets.

Quantified Uncertainty Regarding DSM Energy Savings

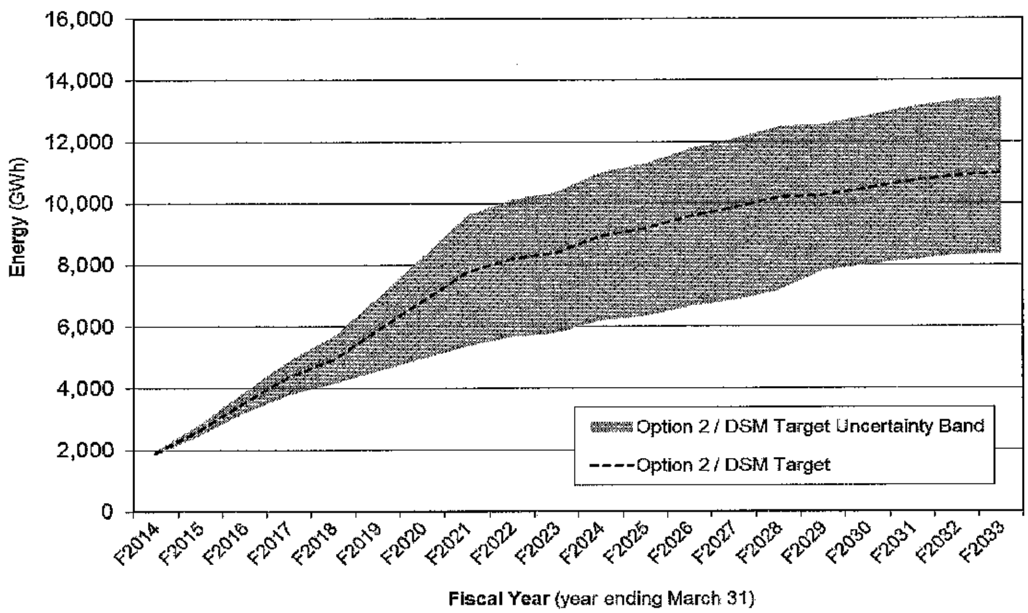
The DSM energy savings uncertainty analysis focuses on quantifying the range of possible outcomes from the following three broad categories:

- DSM programs
- Codes and standards
- Rate structures – changes considered for all major rate classes

BC Hydro undertook analysis of the range of uncertainty for each of these items. By combining all of the quantified sources of uncertainty in a Monte Carlo analysis and adjusting based on professional judgment, BC Hydro produced a quantified range of uncertainty around mid-level DSM estimates. Details of this process can be found in Appendix 4B.

Figure 4-7 puts the high and low DSM savings forecasts into a band of uncertainty around the mid DSM savings forecast for Option 2 as a way of illustrating the range of DSM savings uncertainty around the mid-point estimates. Similar to the load forecast figure, the high and low DSM savings estimates are calculated as the mean of the upper and lower twentieth percentile tails of the distributions. As the results turned out, the fan of uncertainty roughly corresponds to an 80 per cent confidence interval for DSM savings. Figure 4-7 shows uncertainty regarding DSM forecast savings in the near term is low, but this grows over time creating a broad fan of possible levels of DSM savings in the future.

Figure 4-7 Range of Potential Energy Savings for DSM Option 2



However, it must be emphasized that BC Hydro must rely on professional judgment given the uncertainty in assessing DSM deliverability. For example, the assumption made in this analysis is that uncertainty grows in a linear way. This assumption is likely not correct, as uncertainty usually grows in a non-linear way into the future, a factor not captured in this uncertainty analysis. BC Hydro is of the view that given the aggressiveness of the DSM target, there is likely more risk of under-delivery than of over-delivery. Another point of reference is a review of historic DSM savings. Table 4-23 demonstrates historic DSM savings since 2009 and shows that DSM has not either under- or over-delivered to the extent set out in Figure 4-7 above. The year 2009 is chosen because this is the year the DSM Target was introduced and the DSM Target is a significant step up from DSM targets BC Hydro set before 2009.

Table 4-23 DSM Historical Plan and Actual Cumulative Electricity Savings since F2009 (GWh)

	DSM Plan	Actual
F2009	678	1,295
F2010	1,540	1,909
F2011	2,349	2,314
F2012	3,310	3,528
F2013	4,439	4,460

Based on the experience of building several iterations of DSM options, the spread of uncertainty for DSM Options 1 and 3 would be expected to be roughly similar, albeit scaled proportionately to match their levels of savings.

Several observations can be made from this analysis. First, there is a substantial amount of uncertainty for all options when planning for the mid forecast. Second, for DSM Options 1, 2 and 3, there is no clear demarcation between "acceptable" and "unacceptable" with respect to savings uncertainty; each option shows a considerable range of potential outcomes, with the larger DSM portfolios containing both larger downside and larger upside uncertainty.

To the extent that BC Hydro can react to this potential magnitude of DSM under-performance and increase DSM electricity savings to target levels over this timeframe, then DSM savings uncertainty is manageable. However, if the size and timing of the under-performance poses concerns, then deliverability of DSM energy savings is a risk that needs to be considered, both in choosing the appropriate level of DSM and in managing the risk during the implementation of the IRP recommendations. This underscores the importance of having robust DSM performance management and a robust contingency plan to backstop BC Hydro's energy and capacity needs. This latter topic is addressed in section 6.9.

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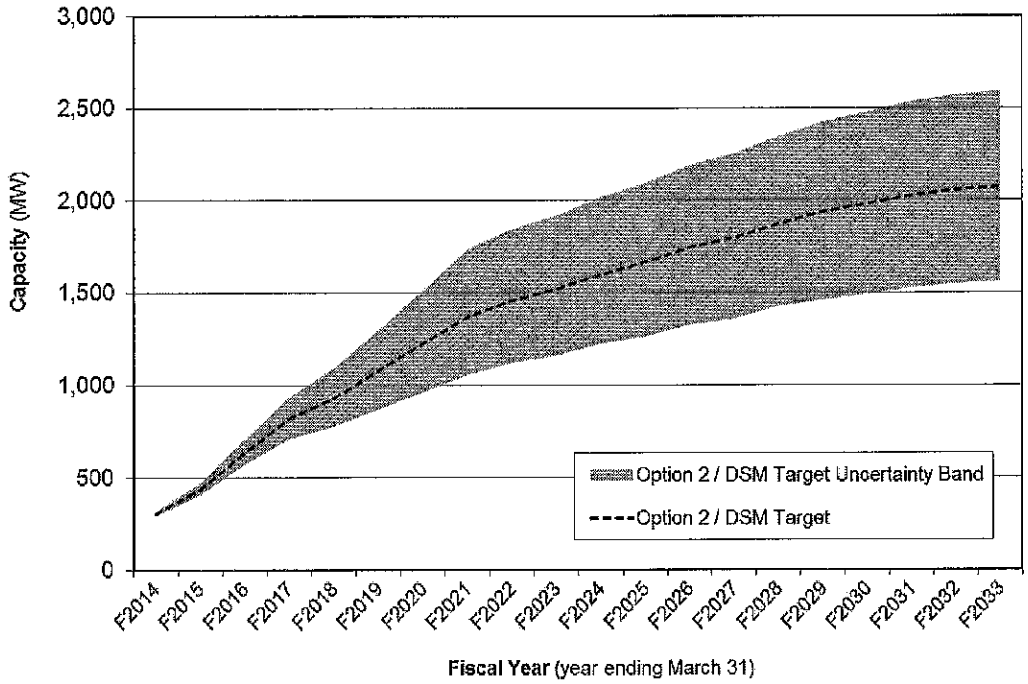
Quantified Uncertainty Regarding DSM Energy-Related Capacity Savings

Energy-focused DSM measures also bring associated capacity savings. Two sources of uncertainty were built into the IRP analysis regarding DSM energy-related capacity savings:

- The underlying uncertainty around the energy savings themselves (as discussed above)
- The capacity factors used to translate energy savings into the associated level of capacity savings

Capacity factors are used to translate general energy savings into peak savings. These parameters are treated as uncertain estimates to capture the lack of precise knowledge about how energy savings from multiple sources would reduce peak demand. Combining the uncertainty around capacity factor estimates and the uncertainty regarding the underlying savings estimates in a Monte Carlo distribution generated a spread of possible capacity savings around the estimate. Details can be found in Appendix 4B. The outcome of this can be seen in the following graph for DSM Option 2 capacity savings over time.

Figure 4-8 Range of Potential Capacity Savings for DSM Option 2



Again, the assumption made in this analysis is that uncertainty grows in a linear way. This assumption is likely not correct for the reason discussed above regarding DSM energy savings.

Similar to DSM energy savings, the range of capacity savings for Options 1 and 3 would be expected to be similar to that shown for Option 2, but proportional to the amount of savings for each option. The observations here somewhat parallel those made with regard to DSM savings uncertainty on the energy side:

- There is significant uncertainty with respect to DSM capacity savings across all options
- Moving to higher levels of DSM increases uncertainty around capacity savings

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- There is no clear quantified demarcation between "acceptable" DSM options and "unacceptable" DSM options with regard to energy-related capacity savings uncertainty when comparing Options 1, 2 and 3

The significant difference that needs to be taken into account on the capacity side is that the consequences of under-delivery of capacity resources are much more severe than on the energy side, and may undermine BC Hydro's fundamental requirement to serve load. As a result, BC Hydro draws the following conclusions:

- Choosing options with higher capacity uncertainty should only be done if the option is a cost-effective resource and if the level of deliverability risk can be adequately managed through other means
- Preparing contingency responses to prepare for the possibility of DSM under-delivery is an important part of BC Hydro's Contingency Resource Plans, regardless of the DSM option chosen. Refer to section 6.9 and section 9.4

Capacity-Focused DSM Savings Uncertainty

While the energy-focused DSM options discussed in the previous section have associated capacity savings, additional capacity savings may be possible through capacity-focused DSM activities. These were described in section 3.3.2 and at a high level, refer to DSM activities that can reliably reduce peak demand over the long-term (also referred to as peak reduction or peak shaving). This section addresses the uncertainty around the capacity savings forecasts.

Capacity-focused DSM savings were grouped into two broad categories:

- Industrial load curtailment
- Capacity-focused programs

BC Hydro has previously entered into load curtailment agreements with industrial customers; however, it is not clear how easily this experience can be translated into agreements that can reliably reduce peak demand over the long-term when and as

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needed. As a result of this, a spread of possible outcomes was constructed around the estimated levels of savings to capture this uncertainty. Details outlining the method for doing this can be found in Appendix 4B.

Table 4-24 Savings from Capacity-Focused DSM and Uncertainty (MW in F2021)

	Industrial Load Curtailment	Capacity-Focused Programs
Low (P10 cutoff)	313	132
Mid (mean or expected)	383	191
High (P90 cutoff)	446	262

Capacity-focused DSM represents a potentially attractive approach to peak reduction. However, there are a number of uncertainties that have been highlighted in this analysis:

- Since BC Hydro is just starting to develop long-term capacity-focused savings options, implementation success is an important issue. In particular, customer participation rates are unknown. This makes it difficult to rely on these approaches to address near-term capacity and contingency needs.
- Once these approaches are established, operational experience will still be required to understand how participation rates and savings per participant translate into peak shaving and whether these peaks are coincident with peak load and whether peak shaving leads to other system peaks. In particular, BC Hydro will need to effectively identify and design around free-ridership to generate peak shaving behaviour change.

Overall Conclusions Regarding Long-Term DSM Savings Uncertainty

BC Hydro is expected to meet the majority of its load growth through DSM. As such, a considerable effort to better understand the uncertainty inherent in this demand-side resource and incorporate it into the decision-making framework is warranted.

Progress has been made since the 2008 LTAP on many of these questions:

- A detailed study on load forecast and DSM integration addressed some overlaps and found that other concerns were already adequately addressed by existing processes
- A more focused jurisdictional review found evidence pertaining to the experiences of other utilities
- A top-down analysis of overall DSM uncertainty tried to capture issues of uncertainty not addressed by the more mechanical, bottom-up Monte Carlo studies

In addition, newly emerging circumstances have brought to the fore some additional areas of interest that are just starting to be explored:

- Ramp-Up Rates – To what extent can DSM activities be moderated when need is not pressing, but then accelerated if and when demand growth increases?
- Capacity – Given the emergent importance of capacity issues in this IRP, and given that DSM efforts and verification to date have been energy-focused, is there additional uncertainty with associated capacity savings?

Despite the advancement in understanding some of these issues, uncertainty around the large DSM savings being targeted continues to be a key uncertainty in long-term resource planning. These are difficult issues that face the electricity industry at large and none of them can be considered "solved". Moreover, data sets and learning continue to evolve over time, even over the course of a long-term planning cycle. As such, professional judgment will continue to play an important role in both the interpretation of data and in balancing DSM deliverability risk with other key energy planning objectives.

4.3.4.3 Net Load and Net Gap Uncertainty

Net load is the level of load after DSM savings. Forecasting net load is subject to the joint uncertainties of forecasting load growth and forecasting DSM savings.

Estimates of the range of outcomes around the forecast were developed for load growth (Chapter 2) and DSM savings (section 4.3.4.2). These were combined to yield a range of possible outcomes for net load, along with the associated relative likelihoods of achieving these outcomes. Details of this process are contained in Appendix 4A.

For most IRP questions, the uncertainty regarding future net load is expressed as a three-point, discrete distribution. Combining the net load distribution for a given DSM option with the existing, committed and incremental resource stack yields a large gap, mid gap,[17] and small gap.[18] To clarify this concept, the table below lays out how these gap levels are defined.

Table 4-25 Gap Terminology

	Small Gap	Mid Gap	Large Gap
Load Assumptions	Low load scenario	Mid-load scenario	High load scenario
DSM Assumptions	High DSM savings scenario, but with scaled back effort. Modelled as low DSM savings	Mid-DSM savings scenario	Low DSM savings

The one change to be noted for this IRP is the definition of the "small gap" scenario. As discussed in section 3.3.1, there is evidence that a reduced load forecast impacts DSM economic potential. In addition, as recent experience has highlighted, a prolonged period of low load growth would likely not be accompanied by BC Hydro continuing to pursue the same level of DSM savings. Rather, efforts would likely to

[17] The mid gap corresponds with the load-resource balance shown in section 2.4.

[18] While "gap" refers to any situation where demand does not meet supply, it is important to note that "gap" could refer to deficit (which requires additional resources to fill) or surplus (which may call for strategies to reduce). In periods of surplus, this traditional terminology can be confusing and so care must be taken in its interpretation.

be scaled back in the face of a prolonged economic slump, even if the conditions for overachieving DSM savings (e.g., high public participation, high savings per participant, large elasticity of demand, better than expected progress on codes and standards implementation) were in place. This combination of scaled-back efforts paired with better than expected DSM savings conditions in a low load growth scenario was modelled as a low level of DSM savings. This approach is a rough approximation to capture dynamic decision-making within a static modelling framework and so some care must be taken when interpreting results involving the low gap (large surplus) scenarios.

These energy gaps (assuming DSM Option 2) are shown Figure 4-9 and Figure 4-10 for energy and capacity, respectively. The gap between load (after DSM) and resources either represents a surplus where costs need to be managed (if supply is greater than demand) or a deficit that must be filled with supply-side resources. If the comparison between load and resources results in a surplus, the IRP analysis considers the costs of selling the surplus into the market.

Figure 4-9 Energy Gap[19]

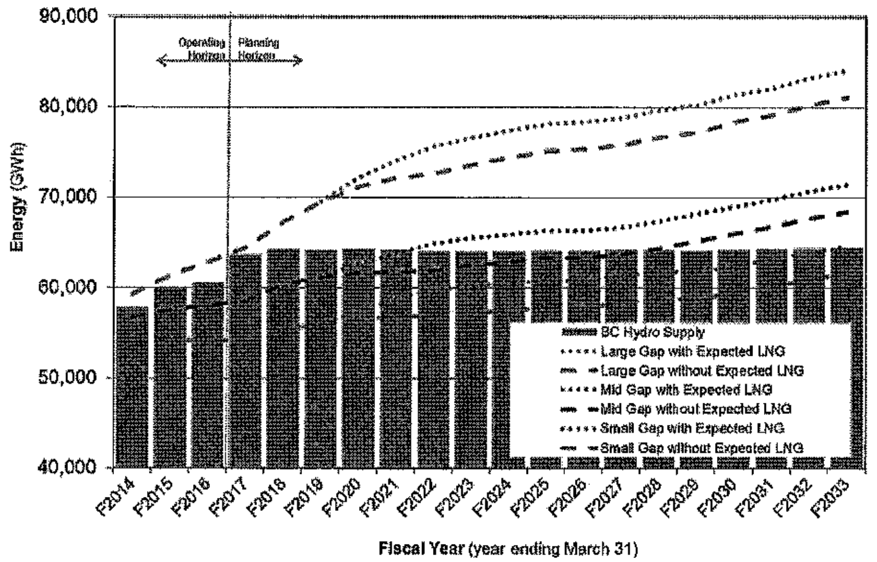
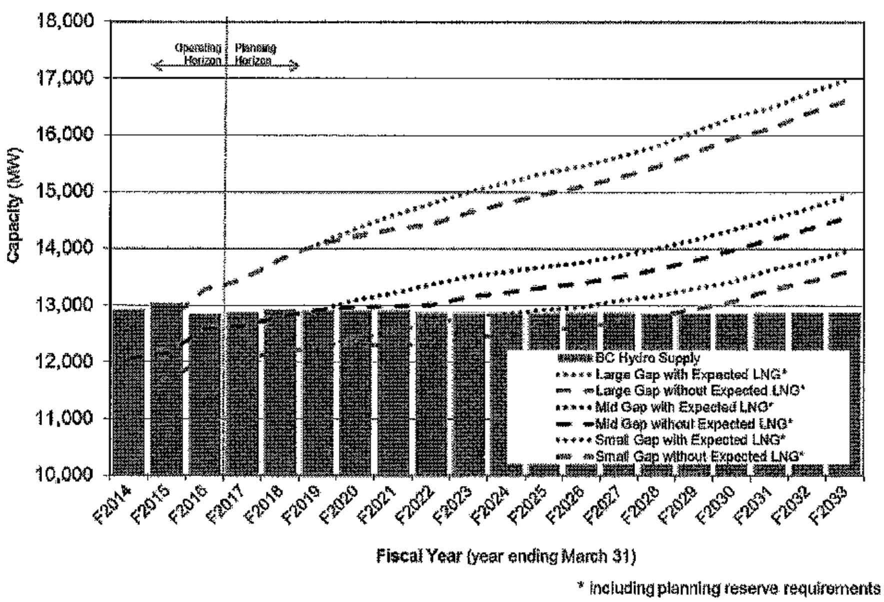


Figure 4-10 Capacity Gap



[19] The y-axis has been magnified to better demonstrate the variation between the six gap scenarios. The energy graph y-axis starts at 40,000 GWh/year and the capacity graph y-axis starts at 10,000 MW.

The conclusions to the key IRP questions addressed in Chapter 6 are collected into a Base Resource Plan (**BRP**). The primary focus of the BRP is to address the needs identified by the mid gap. As such, the majority of the analysis in Chapter 6 is based on the mid gap scenario with Option 2/DSM Target, unless otherwise noted.

BC Hydro develops additional actions for contingency plans that ensure that alternative sources of energy and capacity supply are available if the risks materialize or additional loads develop. In section 6.9, BC Hydro examines the need for additional energy supply if load differs from the mid gap scenario. The large gap scenario is a useful test of how large and how quickly load can differ from the mid gap. It provides guidance on the range of capacity resources that need to be ready, and the required timing of these resources, to respond effectively. Conversely, the small gap scenario helps explain the benefits of flexibility (for example exit ramps) in the case that need is decreased. Refer to section 6.4 for additional discussion of resource flexibility.

4.3.4.4 Market Price Forecast Uncertainty

Using costs to compare portfolios of DSM and supply-side options requires estimating not only the cost of acquisitions, but also the costs and trade revenues of each portfolio operating over the planning timeframe. The operating costs and revenues are affected by:

- Natural gas prices
- Electricity prices for import and export
- GHG allowance and offset prices
- RECs

The future price path of each of the above variables is estimated with uncertainty. These price levels vary over time; their estimated levels and departures from their estimated values are some of the main drivers of long-term planning decisions. A further complication is the inter-relationship between these variables. Chapter 5 explores each of these price forecasts in more detail. Section 5.2 outlines how these uncertainties were combined into five Market Scenarios, to create combinations of factors that:

- Represent a wide, but plausible range of input and output prices
- Avoid combinations that were internally inconsistent
- Are large enough in number to cover key combinations but small enough in number to be tractable within IRP modelling resource constraints

In most cases, the base assumption for the Chapter 6 analysis is Market Scenario 1, as BC Hydro considers this the most likely scenario. Where relevant, resource options were compared using some of the five Market Scenarios to test whether strategies were robust given possible different market price futures.

4.3.4.5 Wind Integration Cost and ELCC Uncertainty

Two main uncertainties were highlighted with respect to wind resources:

- Wind integration costs
- ELCC (discussed in section 3.2.1)

The wind integration cost is described in Appendix 3E. A value of $10/MWh is used as the base case and additional sensitivity tests were performed using $5/MWh and $15/MWh as the lower and upper bounds, respectively.

The determination of the wind ELCC value is described in Appendix 3C. The current analysis suggests an ELCC value of 26 per cent of installed capacity. This value is used as the base assumption for all portfolio modelling. The wind ELCC is modelled as a random variable with a lopsided triangular probability distribution function, using a zero per cent ELCC value as a lower bound (worst case) assumption, 26 per cent as the upper bound (best case) assumption, and 26 per cent as the most likely

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assumption. Changes to this variable did not make a material impact to the overall analysis.

4.3.4.6 IPP Attrition Uncertainty

IPP clean or renewable energy resources are one of the resource options BC Hydro considers to fill the load/resource gap. However, given that recent BC Hydro acquisition processes have resulted in varying rates of attrition, IPP attrition rate is flagged as an uncertainty that could affect the comparison of resource options. For this IRP, BC Hydro adopted a range of attrition rates, bracketing those evidenced in recent acquisition processes. The lower and upper bounds, as well as a best estimate, are shown in Table 4-26. A triangular distribution was developed for Monte Carlo simulation to help inform the range of uncertainty for net gap estimates.

This estimation of IPP deliverability uncertainty could play an important role in estimating risks to supply reliability. However, given the anticipated small role incremental IPP resources are expected to have in the planning horizon based on the reference load forecast and successful implementation of the DSM target, this factor was dropped from analysis in Chapter 6.

Table 4-26 IPP Attrition Rates and Uncertainty (per cent)

	Lowest Credible Bound	Mid (Best) Estimate	Highest Credible Bound
Attrition Rates	5	30	70[20]

4.3.4.7 Resource Options

Chapter 3 outlined the resource options that could be considered in filling the energy and capacity gaps. However, some of these resource options present operational and developmental challenges, as well as uncertainty around their technological

[20] The upper bound for IPP attrition is based on attrition rates from the F2006 Call for Power. The EPAs awarded during this call included two coal-fired generation projects, which were subsequently terminated due to a change in B.C. Government policy.

maturity. As described in section 3.7, only resource options that have proven development in B.C. and meet legal restrictions and B.C. Government policy objectives were included in portfolio modelling;section 4.4.6.1 provides a list of the resources considered.

4.3.5 Applying the Resource Planning Analysis Framework to Comparing Alternatives

Sections 4.3.2 to 4.3.4 outlined how the IRP's resource planning analysis framework provides a process for comparing options, using multiple objectives, given significant planning uncertainty.

Figure 4-11 is used in Chapter 6 in the discussion of modelling results to help clarify which options and uncertainties are being explored and which are fixed with respect to each of the key IRP questions. The legend is intended to clarify the background assumptions against which the resource options are examined. As an example, Figure 4-11 shows a portfolio run that has fixed the DSM target at Option 2/DSM Target, the Market Acenario at Scenario 1, etc. When the modelling choice for each row is filled in, it becomes easier to understand the key underlying variables chosen for each set of portfolios. The portfolio shown in Figure 4-11 represents the base set of assumptions, and many of the IRP questions are examined in relation to this starting point or analysis.

Figure 4-11 Modelling Map and Base Modelling Assumptions

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

4.4 Portfolio Analysis Methodology and Assumptions

BC Hydro's primary method of analyzing resource options is portfolio analysis. Portfolio analysis develops and evaluates resource portfolios, consisting of a sequence of demand-side and supply-side resources (including transmission) to meet customers' energy and capacity needs. Portfolio analysis is part of the overall IRP resource planning analysis framework; and portfolios are compared across the resource planning objectives outlined in Table 4-20 and incorporated the key uncertainties identified in section 4.3.3.

BC Hydro has maintained the same portfolio analysis process as was used in the 2008 LTAP. In its 2006 IEP/LTAP Decision, the BCUC agreed "that a portfolio analysis is consistent with the Commission's Guidelines", and "is a best practice for IEP or IRP analysis".[21] Portfolios for this IRP were created for the planning period from F2017 to F2041.[22]

This section describes the models used and the modelling assumptions made in the portfolio analysis. Figure 4-11 summarizes the range of assumptions made for the key uncertainties present in the portfolios and highlights the base set of assumptions.

4.4.1 Portfolio Analysis Models

This IRP used the same suite of models as was used in the 2008 LTAP, including:

- Hydro Simulation model (**HYSIM**)
- System Optimizer
- Multi-Attribute Portfolio Analysis (**MAPA**)

HYSIM is a system simulation and production costing model developed in-house by BC Hydro which determines a least-cost generation pattern for the large hydropower system using 60 years of historic reservoir inflow records. HYSIM provides insight into how year-to-year inflow variability may impact resource portfolio performance. It is mainly used to estimate the monthly and annual energy produced by the large hydro system under average water conditions. The resulting energy production for the large hydropower plants was input into System Optimizer.

Resource portfolios for the IRP were developed using System Optimizer which is a product of Ventyx. System Optimizer is a deterministic mixed integer programming

[21] 2006 IEP/LTAP Decision, pages 89 and 90.

[22] The four-years prior to F2017 are within the operational timeframe for which long-term planning actions have limited impact. Therefore, resources for these three years are assumed common across all portfolios and are not modelled.

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optimization model that determines an optimal sequence of generation and transmission resource expansions, referred to as a portfolio, for a given set of input assumptions. It does so by minimizing the PV of net cost required to meet a given load under average water conditions. The net costs include the incremental fixed capital and operating costs for new resources, total system production costs, and electricity trade cost and revenues. System Optimizer does not value the ancillary benefits provided by future potential resources such as the ability to integrate intermittent resources and to increase the firm capability of other resources. This value could be significant for resources such as Site C, natural gas-fired generation or pumped storage.

MAPA is a tool developed within BC Hydro that takes the portfolio output from System Optimizer and tracks various attributes of each portfolio such as environmental and economic development attributes which are described in Chapter 3.

For a more detailed description of the models used, refer to Appendix 4C.

4.4.2 Modelling Constraints

The portfolios created satisfy good utility practice (e.g., they meet reliability criteria as described in section 1.2.2). Three *CEA* objectives are treated as constraints: (1) achieve self-sufficiency; [23] (2) meet the 93 per cent clean or renewable electricity target described further in section 6.2; and (3) meet the at least 66 per cent of incremental load growth by year 2020 (F2021) with DSM.

4.4.3 Financial Parameters

The IRP portfolio analysis was performed and presented in F2013 constant dollars. The PVs of the portfolios reflect the costs (or levelized costs where appropriate) for the planning period from F2017 to F2041. The key financial parameters in the IRP

[23] Except as noted in the two year proposed economic bridging to Site C's ISD described in section 9.2.7.

analysis include the following: inflation rate, cost of capital, discount rate and U.S./Canadian exchange rate.

4.4.3.1 Inflation Rate

Where conversion between nominal and real dollars is necessary, an annual rate of 2 per cent was used as the average inflation rate. This assumption is consistent with the B.C. Consumer Price Index (**CPI**) outlook which is provided in the Province of B.C. 2013 Budget and Fiscal Plan. Aside from the annual inflation rate assumption, the IRP includes no other incremental cost escalation or allowance for increasing capital costs. This assumption reflects the 2013 BC Hydro recommended project cost estimation outlook based on the following observations:

- The Bank of Canada announced that its long-term inflation target is centred around the 2 per cent level, and that it will take action if price increases stray outside of a one to three percent band around this mid-point
- While B.C. construction activities have seen a gradual recovery from 2011 to 2012:
    - Market competition for BC Hydro construction projects has remained strong in recent years
    - The continuing strength of the Canadian dollar has been helping to moderate material and equipment procurement costs in international markets
    - Having a national CPI below 2 per cent has been moderating inflationary pressure on the construction sector and contributes to a stable inflation outlook.

4.4.3.2 Cost of Capital

The cost of capital used is the weighted average cost of debt and equity. The weighted average cost of capital (**WACC**) is the rate of return that a company could expect to earn in an alternative investment of equivalent risk. As discussed in section 3.2.2, BC Hydro's WACC is 5 per cent (real), which is a reduction from 6 per cent (real) in the 2008 LTAP. The 5 per cent real rate has been consistently applied in the recent costing of resources developed by BC Hydro such as Resource Smart projects and Site C. BC Hydro used a WACC of 7 per cent (real) for IPPs for the analysis in this IRP. Sensitivity of the portfolio results to this assumption is explored by performing several System Optimizer runs using a 6 per cent (real) WACC for IPP projects, effectively reducing the cost of capital differential between BC Hydro and IPPs from 2 per cent to 1 per cent.

4.4.3.3 Discount Rate

Discount rates reflect the market demand for, or opportunity cost of, the capital associated with projects of similar risk. This IRP used 5 per cent and 7 per cent discount rates to calculate levelized resource unit costs (UECs and UCCs) for BC Hydro and IPP resources respectively. The updated discount rates reflect the change in BC Hydro's WACC and the updated assumption of IPP's WACC. In the long-term planning context, the discount rate methodology is consistent with the WACC used to calculate cost streams of installed resources.

BC Hydro's discount rate is used to calculate PVs of portfolios. This reflects that the evaluations are performed from the utility's perspective.

4.4.3.4 U.S./Canadian Exchange Rate

Assumptions about the U.S. dollar to Canadian dollar exchange rate are required to convert the market price forecasts described in Chapter 5. The assumed conversion rate was 0.9693 USD/CAD, which is similar to the exchange provided by the B.C. Treasury Board in its December 2012 Outlook.[24]

[24] The Treasury Board of the Province of B.C.'s December 2012 Outlook quoted a USD/CAD foreign exchange rate is 0.9770 for F2018 which covers most years of the planning period.

4.4.4 Load/Resource Assumptions

The LRBs shown in Figure 4-3 and Figure 4-4 form the base assumption for resource requirements in the IRP portfolio analysis. These LRBs reflect the December 2012 Load Forecast described in Chapter 2, as well as the near-term cost reduction actions on IPP acquisitions, DSM and VVO, which is described in section 4.2.5. Incremental load scenarios (i.e., large and discrete loads) as described in section 4.3.4.1 are used to create different portfolios to answer specific questions.

4.4.5 Market Price Assumptions

The costs and trade revenues of operating each portfolio over the planning time frame are one element used to compare the portfolios. These operating costs and revenues are affected by the natural gas, GHG, electricity, and REC market price assumptions. Chapter 5 describes these market prices under different market scenarios and how they are used in the IRP analysis. Portfolios were generally created for the most likely or expected Market Scenario as well as across different market scenario(s) where warranted.

4.4.6 Resource Options

Chapter 3 presents an extensive list of resource options within B.C. The resource options described in section 3.6 and 3.7 have been eliminated from consideration in the portfolio analysis. The remaining resource options, referred to as Available Resource Options, are then made available to System Optimizer for creating portfolios.

It is recognized that some of the resources that were screened or not modeled could become viable over the planning horizon. Their exclusion from the IRP portfolio analysis does not imply that they would be excluded from consideration in the IRP recommendations.

4.4.6.1 Available Resource Options

The resource options are available for portfolio analysis are listed below. Apart from pumped storage, all of these resource options have been developed in B.C.

- DSM Options 1, 2/DSM Target, and three savings, and costs attributed to various DSM options which were modelled in System Optimizer
- On-shore wind
- Run-of-river hydro
- Site C (not including sunk costs)
- Biomass – Wood-based biomass (with the exception of the standing timber portion of the potential, which has been excluded in the modeling due to cost and other uncertainty)
- Biomass – municipal solid waste
- Biomass – biogas or landfill Gas (not modeled because it only has small energy and capacity potential, and potentially double counts resources that could be acquired under existing acquisition programs)
- Cogeneration (not modeled because it only has small energy and capacity potential, and potentially double counts resources that could be acquired under the existing acquisition program)
- Resource Smart projects (GMS Units 1-5 Capacity Increase[25] and Revelstoke Unit 6[26])
- Pumped storage:

[25] The first year that these capacity upgrades were available to System Optimizer is F2021 and reflects constraints due to on-going work at GMS.

[26] The first year that the sixth unit at Revelstoke was available to System Optimizer is F2020 and reflects constraints due to on-going work at the Mica and Revelstoke powerhouses.

- There are no commercial pumped storage facilities in B.C., and only one pumped storage facility operating in Canada which was permitted in the 1950s. Siting a pumped storage facility in B.C. triggers a number of regulatory/government agency approvals resulting in timing and outcome uncertainty.
- Pumped storage resources are modeled to be dispatched in generate mode during heavy load/high price periods such as weekdays during the day, and in pump mode during light load/low price periods such as overnight and on Sundays. The sum of the energy produced and consumed by a pumped storage resource was set to yield a net efficiency of 70 per cent (a net energy consumer), which is in line with efficiencies seen at existing pumped storage facilities.

- Gas-fired generation – Section 6.2.3 describes how gas-fired generation is considered for resource planning and sets out the rationale for modelling this resource in portfolios as follows:
  - In portfolios where natural gas-fired generation is an available resource, it is limited by the requirement to comply with the *CEA* 93 per cent clean or renewable energy objective
  - Where natural gas-fired generation is built to serve non-LNG load, the type of generator built is assumed to be a SCGT with a minimum capacity factor of 18 per cent
  - Policy Action No. 18 of the 2007 BC Energy Plan provides that all new natural gas-fired generation must have zero net GHG emissions. The cost to completely offset GHG emissions is captured in the portfolio analysis. These cost assumptions are described in section 5.4.3.3.

4.4.6.2 Resource Option Attributes

The technical, financial, environmental and economic attributes of the Available Resource Options from Chapter 3 are inputs into the portfolio analysis. When evaluated as part of a resource portfolio, the following generic costs are added to the cost of these resources.

- **Soft cost adder:** This is applied to generic resource options or specific projects that do not have discrete cost estimates which specifically include costs related to mitigation, First Nations, public engagement regulatory review costs (i.e., resource options other than Site C and Revelstoke Unit 6. BC Hydro notes that it has not used a soft cost adder for GMS Units 1-5 Capacity Increase, but the addition of this adder would not materially change the results). The UECs and the UCCs described in Chapter 3 do not include mitigation measures, regulatory review, First Nation consultation and public engagement costs. To reflect the fact that developing future generic resource options would entail additional soft cost expenditures, BC Hydro has added 5 per cent to the cost of these resources. BC Hydro chose 5 per cent based on past experience. The environmental assessment, First Nations, and stakeholder engagement costs in a sample of recent representative BC Hydro capital projects ranged from 0.02 per cent to about 10 per cent.
- **Wind integration cost adder:** This is applied to future wind resources. Natural variations in wind speed make the power generated by this resource particularly challenging to both forecast in upcoming hours and days and integrate into the power system on a minute-by-minute basis. Wind power generation is highly variable in the short-term timescale of seconds to minutes resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. The natural variability in wind power generation also makes it difficult to forecast wind in the hour- to day-ahead timeframe, resulting in the need to set aside system flexibility to address the potential for wind generation to either under- or over-generate in

this time frame. Both of these challenges have cost implications that are specific to wind power generation[27] and are quantified in a wind integration cost adder that is used in this IRP analysis as well as previous acquisition processes.

BC Hydro first started to investigate wind integration costs in 2008. A wind integration cost of $10/MWh was applied in the 2008 LTAP portfolio analysis as well as in the subsequent 2010 Clean Power Call evaluation. In 2010 BC Hydro completed a second, more detailed wind integration study which is included in Appendix 3E. This study considered 12 wind integration scenarios which included: (1) two study years representing different load and system generation configurations; (2) two levels of wind location diversity; and (3) three wind power penetration levels. The wind integration costs for the 12 scenarios ranged from $5/MWh to $19/MWh. Generally speaking, wind integration cost increased as the wind penetration level increased, whereas geographic diversification significantly reduced the wind integration cost for all study years and all penetration levels. Given that $10/MWh is within the range, BC Hydro continues to use this figure for a wind integration cost adder in the IRP analysis. This value will periodically be revisited in the future with further studies on wind integration costs. BC Hydro conducted wind cost integration sensitivities, including using a low wind integration cost of $5/MWh and a high wind integration cost of $15/MWh.

- **Network upgrade cost adder:** The network upgrade (**NU**) cost adder reflects the costs borne by BC Hydro when interconnecting resource options to the bulk transmission system. This includes cost of upgrades on the transmission circuits leading from the point of interconnection to the bulk 500 kV circuits. A NU cost, estimated based on average NU costs from the Clean Power Call,

[27] Other renewable resources, such as solar and wave, are also highly variable in short-term timescales. The variability of run-of-river generation is largely contained within the monthly/seasonal timeframe, which is captured in the IRP modeling tools.

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was added to all resource options except for those that have such costs explicitly included in their cost estimates or those that would interconnect directly to a 500 kV system or to a sub-station in close proximity to a 500 kV substation.

4.4.7 Transmission Analysis

The analysis of the long-term transmission requirements in this IRP was based on BC Hydro's Integrated System Planning Criteria (refer to Appendix 2D). These criteria define BC Hydro's guidelines for planning a reliable transmission network that is adequate for dispatching designated generation resources to serve forecasted demand. For system performance under normal and contingency conditions, BC Hydro's planning criteria conform to the BCUC-approved North American Electric Reliability Corporation Reliability Standards for transmission planning.

In accordance with the criteria that require the bulk transmission system to remain within its thermal and stability limits under all demand conditions, the transmission analysis in System Optimizer identifies where and when incremental transmission capacity will be required for a particular portfolio. The power flows on the bulk transmission network are calculated and, if the expected flow on a transmission cut-plane[28] exceeds its most restrictive rating, the cut-plane's total transfer capability is increased. This increase is achieved by selecting a wire or non-wire transmission improvement option (for a list of options refer to section 3.5) that will alleviate congestion along that existing transmission path. The results from System Optimizer are reviewed and, if needed, the reinforcement requirements are adjusted. The PVs of the portfolios presented in Chapter 6 reflect these adjustments.

[28] BC Hydro's critical bulk transmission paths are also referred to as transmission cut-planes. These transmission cut-planes divide the province into regions for transmission analysis (refer to Figure 3-6).

The IRP transmission analysis highlights areas of high-density power flow that may warrant upgrades to the existing bulk transmission grid. It does not compare possible transmission alternatives or recommend optimal transmission solutions. It also does not provide a detailed cost and scope for particular transmission reinforcements.