BC hydro

Integrated Resource Plan

Chapter 8

Recommended Actions

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8.1 Introduction

This chapter presents BC Hydro's 17 Recommended Actions to ensure that BC Hydro can reliably and cost-effectively supply its customers' load requirements under expected (or base) conditions through Base Resource Plans (**BRPs**) and contingency conditions through Contingency Resource Plans (**CRPs**).

BC Hydro developed two BRPs: one that contains Recommended Actions prior to considering load growth from Expected Liquefied Natural Gas (**LNG**) and one that contains the incremental Recommended Actions to address the Expected LNG requirements. Expected LNG load warrants specific analysis and associated recommendations given the potential large size of this identifiable load. Presenting the BRP prior to LNG is consistent with the treatment of the load resource balance (**LRB**) in the Site C Environmental Impact Statement (**EIS**). These actions will be required regardless of the level of LNG load that BC Hydro supplies.

BC Hydro develops CRPs to address load growth and resource uncertainty, including those associated with the delivery of transmission resources. There are two CRPs to address contingencies without Expected LNG load (**CRP1**) and with Expected LNG load (**CRP2**).

The Recommended Actions meet BC Hydro's energy and capacity planning criteria (discussed in section 1.2.2), and align with the British Columbia's energy objectives in section 2 of the *Clean Energy Action* (***CEA)*** as described in section 1.2.3 of this Integrated Resource Plan (**IRP**). Chapter 7 reviews the consultations with First Nations and stakeholders during development of the IRP and the May 2012 Draft IRP. Chapter 7 also provides BC Hydro's response to consultation input to date and a reflection on the extent to which the Recommended Actions contained in this IRP align with these consultations.

For each Recommended Action, BC Hydro:

1. Summarizes the justification found elsewhere in the IRP such as Chapters 4 and 6
2. Sets out the anticipated expenditures. The expenditures are generally provided for the F2014 to F2016 period for each Recommended Action. Longer-term expenditures for large initiatives such as implementing the demand side management (**DSM**) target, and capital costs for projects such as Site C are also provided
3. Lists the steps to be taken over the next five years to advance the specific project or initiative including: 1) risk mitigation measures; and 2) potential major regulatory review processes and other trigger events

As described in Chapters 2, 4 and 6, economic conditions, developments in the mining and gas sectors, the timing and scope of new LNG requirements, and continued uncertainty in the delivery of DSM energy and associated capacity savings contribute to significant uncertainty in the need for new resources. Many of the Recommended Actions are designed to, among other things, keep options open so that BC Hydro can reliably and cost-effectively meet need, while providing off-ramps should the need change.

Approval of the IRP does not by itself lead to implementation of the Recommended Actions. For example, implementing the proposed capital projects entails securing government agency and regulatory approvals, and undertaking additional First Nations consultation and public engagement processes, as required. Pursuing DSM initiatives requires various forms of approval by the British Columbia Utilities Commission (**BCUC**). Thus the IRP provides the long-term planning context for future applications and associated review processes.

8.1.1 Recommended Action Summary

The BRP before Expected LNG addresses the energy and capacity load-resource gaps from F2017 onward set out in section 2.4, after reflecting the DSM Target and Electricity Purchase Agreement (**EPAs**) portfolio cost management initiatives discussed in Chapter 4. This BRP is based on, among other things, the December 2012 mid Load Forecast.

The LNG BRP addresses the incremental LNG expected load of 3,000 GWh/year and 360 MW as discussed in section 2.2.

CRP1 addresses contingencies without Expected LNG load, and CRP2 addresses contingencies with Expected LNG load.

Table 8-1 provides an overview of the 17 Recommended Actions for the BRP, LNG BRP and CRPs.

Table 8-1 IRP Recommended Action Description

Category	IRP Recommended Action	
BASE RESOURCE PLAN		
DSM (Conservation)	1. Moderate current spending and maintain long-term target	Target expenditures of $445 million on conservation and efficiency measures during the fiscal years 2014 to 2016. Prepare to increase spending to achieve 7,800 gigawatt-hours per year in energy savings, and 1,400 MW in capacity savings, by F2021.
	2. Pursue DSM capacity conservation	Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term.
	3. Explore more codes and standards	Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost and to gain knowledge and confidence about their potential to address future or unexpected load growth.
Portfolio Cost Management	4. Optimize existing portfolio of IPP resources	Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.

Category	IRP Recommended Action	
	5. Customer incentive mechanisms	Investigate incentive-based pricing mechanisms over the short term that could encourage potential new customers and existing industrial and commercial customers looking to establish new operations or expand existing operations in BC Hydro's service area.
Supply-Side Resources	6. Continue to advance Site C	Build Site C to add 5,100 GWh/year of annual energy and 1,100 MW of dependable capacity to the system for the earliest in service date of F2024 (for all six generating units) subject to: environmental certification; fulfilling the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and Provincial Government approval to proceed with construction.
	7. Pursue bridging options for capacity	Fill the short-term gap in peak capacity with cost-effective market purchases first and power from the Columbia River Treaty second.
Transmission Resources	8. Advance reinforcement along existing GMS-WSN-KLY 500 kV transmission line	Advance reinforcement of the existing GM Shrum-Williston-Kelly Lake 500 kV transmission lines to be available by F2024.
	9. Reinforce South Peace transmission	Review alternatives for reinforcing the South Peace Regional Transmission Network to meet expected load.
LNG BASE RESOURCE PLAN		
Supply-Side Resources	10. Explore natural gas-fired generation for the north coast	Working with industry, explore natural gas supply options on the north coast to enhance transmission reliability and to meet the expected load.
	11. Explore clean energy supply options, if LNG demand exceeds available resources	Explore clean or renewable energy supply options and be prepared to advance a procurement process to acquire energy from clean power projects, as required to meet LNG needs that exceed existing and committed supply.
Transmission Resources	12. Advance reinforcement of the transmission line to Terrace	Advance reinforcement of the existing 500 kV transmission line from Prince George to Terrace, which includes development of three new series capacitor stations and improvements in the existing BC Hydro substations to be available by F2020.

Category	IRP Recommended Action	
Other	13. Horn River Basin and northeast gas industry	Continue discussions with B.C.'s northeast gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.
CONTINGENCY RESOURCE PLAN		
Supply-Side Resources	14. Advance Revelstoke 6 Resource Smart project	Advance the Revelstoke Generation Station Unit 6 Resource Smart project to preserve its earliest in-service date of F2021 with the potential to add up to 500 megawatts of peak capacity.
	15. Advance GM Shrum Resource Smart project	Advance Resource Smart upgrades to GM Shrum Generating Station Units 1–5 with the potential to gradually add up to 220 MW of peak capacity starting in F2021.
	16. Investigate natural gas generation for capacity	Working with industry, explore natural gas supply options to reduce their potential lead time to in-service and to develop an understanding of where and how to site such resources, should they be needed.
Other	17. Fort Nelson area supply options	Investigate procurement options to serve future Fort Nelson load.

8.1.2 Action Plan Alignment with BRP & CRP Scenarios

Table 8-2 is a summary of how the Recommended Actions are developed to align to the BRP, the BRP for Expected LNG load, and the two CRPs.

Table 8-2 IRP Recommended Action Category Summary

IRP Recommended Action		Category	BRP	LNG BRP	CRP1 and CRP2
1	BC Hydro DSM Target	**DSM (Conservation)**	✓		
2	DSM Capacity Options	**DSM (Conservation)**	✓		
3	DSM Codes and Standards Support	**DSM (Conservation)**	✓		
4	IPP EPA Portfolio	**Portfolio Cost Management**	✓		
5	Customer Incentive Mechanisms	**Portfolio Cost Management**	✓		
6	Site C	**Supply-Side Resources**	✓		

IRP Recommended Action		Category	BRP	LNG BRP	CRP1 and CRP2
7	Bridging Capacity from Market Resources	**Supply-Side Resources**	✓		
8	Existing GMS-WSN-KLY 500 kV Transmission Corridor	**Transmission Resources**	✓		
9	South Peace Transmission	**Transmission Resources**	✓		
10	Natural Gas-Fired Generation for the North Coast	**Supply-Side Resources**		✓	
11	Clean or Renewable Energy for High LNG Demand	**Supply-Side Resources**		✓	
12	Reinforcement of 500 kV line to Terrace	**Transmission Resources**		✓	
13	Horn River Basin and Northeast Gas industry	**Other**		✓	
14	Revelstoke Unit 6	**Supply-Side Resources**			✓
15	GMS Units 1-5 Capacity Increase	**Supply-Side Resources**			✓
16	Natural Gas-Fired Contingency Options	**Supply-Side Resources**			✓
17	Fort Nelson Supply	**Other**			✓

8.1.3 Chapter Structure

The remainder of this chapter is laid out as follows:

- Section 8.2 describes the nine BRP Recommended Actions without Expected LNG load, shows the energy and capacity LRBs after implementation of the nine Actions, and provides BC Hydro's Long Run Marginal Cost (**LRMC**) for the period F2014 to F2033
- Section 8.3 describes the four BRP Recommended Actions to address Expected LNG load, with an emphasis on a flexible and staged approach to address LNG load uncertainty

- Section 8.4 provides a description of the four Recommended Actions associated with BC Hydro's two CRPs, along with a summary of the foundation for the CRPs
- Section 8.5 contains additional recommendations relating to: electrification, export market analysis, transmission planning for generation clusters, and the future IRP submission cycle

8.2 Base Resource Plan

BC Hydro's BRP before Expected LNG provides a 20-year view of the portfolio of generation and transmission resources needed to address the energy and capacity load-resource gaps depicted in section 2.4. The nine BRP Recommended Actions will allow BC Hydro to meet its current and future customers' electricity needs on a reliable and cost-effective basis.

To ensure fair and open access to the transmission system, BC Hydro has a number of procedures governed by its Open Access Transmission Tariff (**OATT**), including the use of a queue to ensure transmission service requests are dealt with in a 'first-come, first-served' manner. Once the IRP is approved, BC Hydro will submit this BRP and the LNG BRP described in section 8.3 as transmission service requests under the OATT tariff. Transmission requests for contingency plans are discussed in section 8.4.

This section includes the following subsections:

- Subsection 8.2.1 to 8.2.9 present the nine BRP Recommended Actions, along with their justification, their execution plan and risk mitigation, and their respective future approval processes
- Subsection 8.2.10 depicts the energy and capacity LRBs that will result from successful implementation of the nine BRP Recommended Actions

- Subsection 8.2.11 summarizes BC Hydro's energy and capacity LRMCs for the period F2014 to F2033

8.2.1 Recommended Action 1: Moderate current DSM spending and maintain long-term target

Target expenditures of $445 million ($175 million, $145 million, and $125 million per year) on conservation and efficiency measures during F2014 to F2016. Prepare to increase spending to achieve 7,800 GWh/year in energy savings, and 1,400 MW in capacity savings, by F2021.

The Recommended Action is to continue working toward BC Hydro's current DSM target originally established in the 2008 LTAP. The remaining savings of the original target is 7,800 GWh by F2021. This is equivalent to reducing new electricity demand by approximately 78 per cent over that period without Expected LNG load (the corresponding figure with Expected LNG load is about 69 per cent). The DSM plan to achieve that target would involve investment in DSM programs at about the same rate as has been done over the past four years, but which is reduced from the previous DSM plan shown in the F2012-F2014 Revenue Requirements Application (**RRA**), as described in Chapter 4.

Implementation of the DSM plan as currently conceived to achieve the DSM target is forecast to save approximately 7,000 GWh/year and 1,400 MW by F2021, with losses:

- While the current DSM plan F2021 savings are somewhat lower than the target, in the following years the DSM plan is expected to result in the same level of savings as that target
- The DSM target of 7,800 GWh/year is a P50, which is a mid-level estimate established in the 2008 LTAP, and as such, some variation between current plan savings and the target is expected. As described in Chapter 4, DSM energy savings for Option 2/DSM Target are P50 estimates and there is

uncertainty with over or under-delivery of energy savings represented by the high and low forecasts. The difference between the planned and targeted energy savings in F2021 is within a reasonable variance (i.e., +/- 10 per cent) and is within 2 per cent of the DSM target levels by the Site C earliest in-service date (**ISD**) of F2024.

Depending on actual DSM performance, expenditures and program activity levels can be adjusted in future years. For this section 8.2.1, energy savings, associated capacity savings and expenditures are based on the plan to achieve the DSM target.

The utility cost (**UC**), which is the implementation cost of pursuing the DSM target over the period of F2014 to F2016 is estimated to be approximately $445 million. Table 8-3 below summarizes the UC by component type.

Table 8-3 Utility Cost of DSM Target ($ million) (cumulative over the years indicated)

	3 years: F2014 to F2016	8 years: F2014 to F2021	20 years: F2014 to F2033
Codes and Standards	9	24	67
Rate Structures	10	21	51
Programs - Total			
Programs - Residential	56	154	470
Programs - Commercial	131	382	1,271
Programs - Industrial	173	465	1,220
Sub-total -Programs	360	1,001	2,961
Supporting Initiatives	67	182	512
Total	445	1,228	3,591

The DSM plan will have approximately $6.5 billion in aggregate customer bill savings over the 20-year period.

The energy and associated capacity savings in F2021 from implementation of the plan to achieve the recommended DSM target are set out in Table 8-4 and Table 8-5 respectively.

Table 8-4 DSM Implementation Plan: Cumulative Energy Savings since F2013 at Customer Meter in F2021

	Codes and Standards (GWh/year)	Rate Structures (GWh/year)	Programs (GWh/year)	Total (GWh/year)
Residential	1,639	472	339	2,449
Commercial	617	356	778	1,751
Industrial	84	304	1,717	2,105
Total	2,340	1,132	2,834	6,306

Table 8-5 DSM Implementation Plan: Cumulative Capacity Savings since F2013 in F2021 at Customer Meter

	Codes and Standards (MW)	Rate Structures (MW)	Programs (MW)	Total (MW)
Residential	401	0	79	479
Commercial	123	120	193	437
Industrial	7	72	370	449
Total	531	192	642	1,365

8.2.1.1 Justification

The plan to achieve the DSM target is technically feasible, cost-effective as measured by total resource cost (**TRC**) and UC, and achievable.

As is apparent from Table 8-6, codes and standards and conservation (stepped) rate structures have the lowest UC. BC Hydro's expenditures in support of codes and standards are justified on the grounds that they are cost-effective even if only 1 per cent of savings are attributable to BC Hydro's efforts. BC Hydro is confident that its expenditures in support of codes and standards will be critical to the achievement of considerably more than 1 per cent of the savings.

Beginning in April 2006, BC Hydro implemented four conservation rates with inclining block (stepped) rate structures for residential, commercial and industrial customers. Given the LRMC described in section 8.2.11, BC Hydro is in the process of revisiting the stepped rate pricing signals starting with the Residential Inclining

Block (**RIB**) rate.[1] However, BC Hydro is not proposing a return to flat rates given: 1) there is a need for energy in F2017 without any further DSM initiatives; and 2) conservation rate structures are longer-term initiatives that are not easily re-introduced.

The remainder of this section focuses on the DSM program component of the DSM target.

Need: BC Hydro forecasts an energy gap and a capacity gap from F2017 onward. To address these gaps, BC Hydro looks first to DSM and the associated energy savings from codes and standards, stepped rate structures and programs. However, the tools employed to achieve the DSM target are integrated. Significant adjustments to any of the tools could impact the ability to achieve the planned level of energy savings delivered by the other tools.

As the activity level with programs is more flexible and easier to ramp up or down over shorter time periods, BC Hydro looks to adjust the DSM program component in the near-term to reduce upward rate pressures, while still maintaining the flexibility to ramp up. This action is described below in section 8.2.1.2.

Cost-Effectiveness: Activities should be cost-effective to ensure BC Hydro's investments in DSM will generally be lower than the LRMC and reduce overall revenue requirements while providing broad opportunities for participation across customer sectors. Cost-effectiveness is measured by the TRC and UC.

As set out in Chapter 3, pursuing the plan to achieve the DSM target would deliver electricity savings at an average unit cost of approximately $32/MWh.[2] Table 8-6 below shows the cost-effectiveness of the plan to achieve the DSM target at both a

[1] The inclining block rate structure for BC Hydro's largest industrial customers, Rate Schedule 1823 (referred to as the Transmission Service Rate or **TSR**) is being examined as part of the Industrial Electricity Policy Review.

[2] The net DSM cost of $8/MWh reflects deemed natural-gas benefits and deemed non-energy benefits as defined in the DSM Regulation.

tool and individual program level using the LRMC range of between $85/MWh and $100/MWh (described in section 8.2.11 below); and Table 8-7 sets out the Net TRC and savings pertaining to DSM programs:

- All three DSM tools (codes and standards, rate structures and programs) encompassed by the plan to achieve the DSM target across all sectors have a TRC benefit-cost ratio greater than 1.0, which is the BCUC accepted standard
- Programs with a TRC benefit-cost ratio greater than 1.0 indicate the program costs are lower than the LRMC. With the exception of the DSM New Home program, and the Low Income program using a LRMC of $85/MWh, all programs have a TRC ratio of at least 1.0. The New Home program is expected to be substantially complete by F2015.
- With the exception of the Low Income program, all DSM tools encompassed by the plan to achieve the DSM target across all sectors have a UC benefit-cost ratio greater than 1.0. A benefit-cost ratio above 1.0 indicates that the program would lower BC Hydro revenue requirements and therefore the aggregate customer bill.

Table 8-6 DSM Implementation Plan – UC and TRC Benefit-Cost Ratios at Alternate LRMCs[3]

	LRMC at $100/MWh		LRMC at $85/MWh	
	UC Test	TRC Test	UC Test	TRC Test
Codes and Standards	**117.1**	**5.5**	**99.5**	**4.7**
Rate Structures	**16.4**	**10.0**	**14.0**	**8.5**
DSM Programs				
Residential Sector				
Behaviour	3.5	4.8	3.0	4.1
Refrigerator Buy-Back	1.5	2.1	1.2	1.7
Low Income	0.9	1.0	0.7	0.9
New Home	1.3	0.7	1.1	0.6
Residential Rebate	1.8	1.8	1.6	1.5
Renovation Rebate	2.5	1.2	2.1	1.0
Load Displacement	6.5	2.4	5.5	2.0
Residential Sector Total	*2.4*	*2.0*	*2.1*	*1.7*
Commercial Sector				
Power Smart Partner	1.9	1.7	1.6	1.4
Product Incentive	2.2	1.6	1.9	1.4
New Construction	2.2	1.4	1.8	1.2
Lead by Example	1.1	1.1	1.0	1.0
Load Displacement	2.5	1.4	2.1	1.2
Commercial Sector Total	*2.0*	*1.6*	*1.7*	*1.3*
Industrial Sector				
Power Smart Partner – Transmission	4.0	2.3	3.4	2.0
Power Smart Partner – Distribution	1.9	1.7	1.6	1.4
Load Displacement	3.2	2.9	2.7	2.5
Industrial Sector Total	*3.2*	*2.3*	*2.7*	*1.9*
Total Programs	**2.6**	**2.0**	**2.2**	**1.7**
Portfolio Total	**5.2**	**3.1**	**4.4**	**2.7**

[3] Benefit-cost ratios for rate structures and programs include supporting initiative costs. Supporting initiatives include public awareness and education, community engagement, technology innovation, information technology, and indirect and portfolio enabling.

Table 8-7 DSM Programs TRC and Savings

DSM Programs (sorted by TRC net of capacity benefits)	***TRC net of capacity benefits ($/MWh)***	***Forecast Savings in F2021 (GWh/yr)***	***Cumulaltive Savings (GWh)***	***% of Total Cumulative Savings***
Behaviour	6	135	135	5%
Load Displacement - Industrial	27	432	567	20%
Refrigerator Buy-back	35	66	633	22%
Power Smart Partner - Transmission	36	1,021	1,653	58%
Load Displacement - Res	42	0	1,653	58%
Residential Rebate	45	53	1,706	60%
Power Smart Partner - Distribution	51	265	1,971	70%
Power Smart Partner - Com	54	450	2,421	85%
Product Incentive	55	173	2,594	92%
Lead by Example	76	28	2,622	93%
Renovation Rebate	77	56	2,678	94%
Load Displacement - Com	78	4	2,682	95%
New Construction	83	123	2,805	99%
Low Income	111	20	2,825	100%
New Home	113	8	2,834	100%

The plan to achieve the DSM target encompasses a comprehensive portfolio of DSM measures with a broad offering to all customer sectors designed to complement one another and capture synergies. Refer to section 8.2.1.2 for more detail concerning the percentage of BC Hydro's DSM program spend by customer sector for the F2014 to F2016 period. The DSM plan will result in approximately $6.5 billion in aggregate customer bill reductions. The DSM program component is flexible and can be changed over time in response to new information.

Environmental and Economic Development Benefits: DSM avoids the environmental impacts associated with the construction of new generation facilities. Incremental DSM provides economic development benefits through the creation and retention of jobs and increased GDP. It also provides opportunities for customers to save money on their electricity bills and for industry to improve its competitiveness.

Policy Alignment: The DSM target aligns with several of the energy objectives contained in section 2 of the *CEA*, as discussed in section 1.2.3. A key *CEA* objective for DSM is the objective to reduce the expected increase in demand by at least 66 per cent by 2020 (*CEA* objective 2(b)). The DSM target achieves a 78 per cent reduction in the expected increase in demand without potential LNG load.[4]

8.2.1.2 Execution

BC Hydro is proposing to adjust expenditures for DSM programs over the next three years while maintaining the potential to achieve higher DSM savings in the long term. A primary challenge in adjusting DSM programs is ensuring that programs remain a viable, low-cost resource to address future energy and capacity gaps. In Chapter 4, BC Hydro examined two 'alternative means' (functionally different ways) of achieving the DSM target in F2021:

- DSM Alternative Means 1 (status quo – no DSM program expenditure reduction)
- DSM Alternative Means 2 (near-term expenditure reductions, ramping back up to the DSM target generally by F2021)

A potential third path to the DSM target was also explored, which would reduce expenditures further than Alternative Means 2 in the near-term (to $100 million in F2016) and aggressively ramps up to higher levels of activity in F2017. However, even with the aggressive ramp-up rate, this path fails to return to the energy savings levels of the DSM target by F2021. There are additional energy savings delivery risks associated with a further reduction of expenditures and the aggressive ramp-up rate.

BC Hydro recommends DSM Alternative Means 2. The planned adjustments to DSM program activities and expenditures in the near term result in potential savings of $330 million over F2015 to F2022 relative to Alternative Means 1. These reduced expenditures will result in almost 900 GWh/year of lower cumulative DSM energy

[4] The DSM target achieves a 69 per cent reduction in demand if Expected LNG load is included.

savings by F2021. F2014 is a transition year as approximately $65 million in project incentives is already committed.

In developing these reduced expenditures and maintaining the ability to ramp up, BC Hydro employed the following principles: 1) eliminate projects or activities that have a short energy savings persistence and thus only contribute to the near-term surplus period; 2) consider 'lost opportunities' by (a) continuing to offer incentives for energy savings opportunities that will not be available in the future (e.g., one time opportunities for incremental improvement to building envelope upgrades or new construction) and (b) defer incentives for energy savings opportunities that are not needed now but will have a predictable uptake regardless of when they are offered; 3) maintain program activities to retain a level of customer and trades engagement and relationships so that DSM programs can be ramped up to long-term savings targets as needed; 4) consider cost-effectiveness of DSM programs from both the UC and TRC perspectives; and 5) consider broad opportunities for customers to participate.

To maximize the range of ratepayers able to participate in DSM and benefit from lower bills, BC Hydro needs to strike a portfolio level balance between ensuring overall cost-effectiveness and equity. Other considerations include the availability of opportunities to each sector and the barriers in each market.

Table 8-8 sets out the percentage of BC Hydro's DSM program spend by sector for the F2014 to F2016 period and Table 8-9 sets out the energy savings delivered from each customer class. While residential expenditures are lower, they deliver a considerable amount of savings through codes and standards activity.

Table 8-8 Percentage of DSM Program Spend by Sector (F2014-F2016)

Residential	Commercial	Industrial
16%	36%	48%

Table 8-9 Percentage of DSM Energy Savings by Sector (F2021) (includes programs, codes and standards, and rate structures)

Residential	Commercial	Industrial
39%	28%	33%

Risk Mitigation: Over the medium and longer-term, risk mitigation is aimed at two key risks: deliverability of energy and capacity savings, and costs to deliver those savings. DSM risk mitigation includes:

- **Initiative Design:** DSM initiatives are designed to consider risk. For example, DSM programs are designed to successfully attract customer participation based on information from market research, jurisdictional reviews and consultations with customers, retailers and trade allies.
- **Incentive Design:** Several DSM programs use incentive structures that ensure BC Hydro provides an appropriate financial incentive for individual projects and limits the amount needed to achieve DSM electricity savings.
- **Tracking Performance Metrics:** BC Hydro tracks program electricity savings and costs on a monthly basis. BC Hydro also tracks leading and lagging performance indicators for each DSM initiative.
- **Savings Estimates and Verification:** BC Hydro undertakes a comprehensive approach to estimate the electricity savings from each DSM initiative and periodically updates its savings information based on the results
- **Management Oversight:** Regular oversight is done at both the DSM initiative and plan levels. During the implementation of a program or initiative, risks are monitored through the tracking of indicators as described above. Management judgement, industry input and stakeholder feedback are then combined with these key performance indicators when assessing changes to programs and initiatives.

- **Plan and Initiative Adjustments:** Adjustments are made at the initiative and plan levels as required. For example, if a program is not performing as expected or if there is new information that could impact a program, adjustments can be made to the program.

BC Hydro also addresses DSM deliverability risk through the two CRPs set out in section 8.4.

8.2.1.3 Future Review Process

Implementation of the DSM target will require two applications to the BCUC in the next six months:

- **RIB:** BC Hydro will be making a RIB rate application to the BCUC in October 2013 pursuant to sections 58 to 61 of the *Utilities Commission Act* (***UCA***) to request approval of new-pricing principles[5] that would apply for F2015 and F2016;
- **DSM Expenditures for F2014 to F2016:** BC Hydro will file a DSM expenditure schedule for F2014 to F2016 pursuant to subsection 44.2(1)(a) of the *UCA* with the BCUC for acceptance with expenditures of $175 million, $145 million and $125 million for the three years. In considering whether to accept the DSM expenditure schedule for F2014 to F2016, the BCUC must, pursuant to subsection 44.2(5.1) of the *UCA*, consider the interests of persons in B.C. who receive or may receive service from BC Hydro; and consider and be guided by the applicable section 2 *CEA* British Columbia's energy objectives, an applicable approved IRP, and the extent to which the proposed DSM initiatives are cost-effective within the meaning of the DSM Regulation. BC Hydro will consult with the customer interveners Association of Major Power Consumers, B.C. Sustainable Energy Association, British Columbia Pensioners' and

[5] A pricing principle is a high level guiding principle that determines how price changes are applied to individual elements of a rate.

Seniors' Organization and Commercial Energy Consumers and other interested parties as to the two timing options for the F2014 to F2016 DSM expenditure schedule filing: 1) October 2013; and 2) February 2014 as part of the F2015/F2016 RRA.

8.2.2 Recommended Action 2: Pursue DSM capacity conservation

Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term. *Pilot voluntary capacity-focused programs (direct load control) for residential, commercial and industrial customers over two years, starting in F2015.*

While the DSM target described in section 8.2.1.1.has significant associated capacity savings of 1,400 MW in F2021, additional capacity savings may be possible through DSM capacity activities (also referred to as peak reduction, peak shaving or load shifting). Capacity-focused DSM is grouped into two broad categories:

- **Industrial Load Curtailment:** This DSM option targets customers who agree to curtail load on short notice provided by BC Hydro during peak periods. BC Hydro proposes to implement a voluntary load curtailment program with BC Hydro's industrial customers to be developed and implemented in stages between F2015 and F2018. This program will identify how much long-term capacity savings are available and can be relied upon for long-term planning purposes;
- **Capacity Programs:** This DSM option would consist of voluntary programs that leverage equipment and load management systems to enable peak load reductions to occur. BC Hydro proposes to pilot capacity-focused programs (direct load control) for residential, commercial and industrial customers over two years, starting in F2015.

Table 8-10 summarizes the UC of capacity-focused DSM.

Table 8-10 Utility Cost of Capacity-Focused DSM ($ million)

	Three years: F2014 to F2016
Industrial Load Curtailment	0.75
Capacity-Focused Programs	5.00
Total	5.75

As described in Chapter 3, capacity-focused DSM represents a new capacity resource to BC Hydro and is subject to uncertainty with respect to its ability to reduce the system peak over the long-term.

In general, experience is needed to see how savings for each initiative translates into peak reduction for the entire BC Hydro integrated system. BC Hydro has had experience with load curtailment programs for large industrial customers. To date, these programs have not resulted in a long-term commitment either by BC Hydro to acquire load curtailment, or customers to interrupt or adjust operations when and as required. Other jurisdictions have established practices of relying on long-term load curtailment for peaking capacity and some forms of operational reserve. BC Hydro will consider these jurisdictional practices, taking into account their differences and experiences. For these reasons, BC Hydro will not yet rely on capacity savings from capacity-focused DSM for resource planning purposes, and thus potential capacity-focused DSM savings are not included in the DSM target at this time.

8.2.2.1 Justification

Need – Assuming implementation of the DSM target and EPA renewals, there is a need for capacity resources beginning in F2021 without LNG and in F2020 with Expected LNG load. BC Hydro proposes to address the short-term peak capacity gap (without LNG load) from F2021 to F2023 with a series of bridging measures such as market purchases and power from the Columbia River Treaty (referred to as the Canadian Entitlement (**CE**)). Capacity-focused DSM provides the capacity potential to reduce the need for bridging resources. Implementation will provide BC Hydro with information on the cost and impacts of capacity-focused DSM, which will inform decisions on whether to rely on capacity-focused DSM as a long-term capacity resource.

Cost-Effectiveness: Industrial load curtailment and capacity-focused programs have the potential to deliver cost-effective capacity savings over the long-term. Costs would be managed against BC Hydro's capacity LRMC.

Environmental Attributes: Capacity-focused DSM may avoid the need for some of the market bridging mechanisms, resulting in a lower environmental footprint.

Policy Alignment: Capacity-focused DSM would support BC Hydro in meeting the legally binding self-sufficiency requirement (*CEA*, subsection 6(2)).

8.2.2.2 Execution

BC Hydro will design and then launch a voluntary industrial load curtailment offer and capacity-focused programs (direct load control). For load curtailment, BC Hydro envisions the following:

- F2015: BC Hydro will work with industry to explore the level of interest and curtailment opportunity, and to develop conceptual program offers, including contractual terms and conditions
- F2016 – F2017: BC Hydro will test the conceptual offers to understand the industry's response and key integration aspects. BC Hydro will launch the full program offer allowing industry to respond to and be comfortable with the program. The program can then be expanded (by number of participants or level of participant commitment in hours or MW) based on future BC Hydro need (MW) and value ($/kW-year).

The following steps are anticipated for the direct load control part of capacity-focused DSM programs:

- F2015 – F2016:BC Hydro will implement a voluntary two-year pilot program for residential, commercial and industrial customers in a specific region to test conceptual offers, understand key integration aspects, and design the program offer

- In F2017, BC Hydro will launch the full program

BC Hydro will employ the same risk mitigation tactics as for the DSM target. Refer to section 8.2.1.2.

8.2.2.3 Future Approval Process

BC Hydro will file an expenditure schedule with the BCUC for acceptance of expenditures for F2014 to F2016 pursuant to subsection 44.2(1)(a) of the *UCA*, as part of the DSM expenditure schedule described in section 8.2.1.3 with respect to the DSM target.

8.2.3 Recommended Action 3: Explore more codes and standards

Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost and to gain knowledge and confidence about their potential to address future or unexpected load growth.

This action has an approximate cost of $1.5 million per year for F2015 and F2016. (There are no F2014 expenditures).

8.2.3.1 Justification

Opportunities to leverage additional levels of DSM-related codes and standards support provides the potential to deliver a substantial amount of additional cost-effective electricity savings. However, there is considerable uncertainty regarding the implementation and achievement of these additional electricity savings. This action will investigate and further develop the range of codes and standards tactics to reduce uncertainty about their feasibility and/or savings estimates and ultimately inform subsequent IRPs. By doing so, it is expected that this recommended action will support further government work. An example is the

Pacific Coast Collaborative's[6] "2012 West Coast Action Plan on Jobs" that among other things seeks to jointly develop energy efficiency standards for appliances such as television set-top boxes, lighting, television, battery chargers, computer/servers and standby losses for a broad range of electronics.

8.2.3.2 Execution

BC Hydro will undertake a range of activities focused on additional codes and standards, including: 1) strategy development; 2) market research, studies and opportunity assessments; 3) measure design, including modeling and cost-benefit analysis; 4) customer, trade ally and/or stakeholder engagement; and 5) pilot programs. BC Hydro will design and manage these activities to achieve the objectives of enhanced certainty at a reasonable cost.

8.2.3.3 Future Approval Process

BC Hydro will file an expenditure schedule with the BCUC for acceptance of expenditures for F2014 to F2016 pursuant to subsection 44.2(1)(a) of the *UCA*, as part of the DSM expenditure schedule described in section 8.2.1.3 with respect to the DSM target.

8.2.4 Recommended Action 4: Optimize existing portfolio of IPP resources

Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.

The combined independent power producers (**IPP**) supply and targeted DSM results in BC Hydro having an adequate energy supply until F2027 and adequate capacity supply until F2021 (without LNG load), as shown in section 4.2.6. BC Hydro is undertaking time-critical actions over the next few months to prudently manage the

[6] On June 30, 2008, B.C., Alaska, California, Oregon and Washington State signed the Pacific Coast Collaborative Agreement.

costs of the energy resources that it has acquired, committed to or planned to target over the next five years. These actions include negotiating agreements to defer commercial operation date (**COD**), downsize or terminate pre-COD EPAs. Based on the EPA actions and Standing Offer Program (**SOP**) rule amendments identified below, BC Hydro expects to achieve an energy supply reduction of contracted energy by F2021 of roughly 1,800 GWh/year, translating into a reduction in attrition-adjusted forecasted firm energy supply of about 160 GWh/year by F2021.

8.2.4.1 Justification

The energy and capacity LRBs depicted in section 4.4.2.6 after implementation of the DSM target and EPA renewal assumptions show:

- There is an energy gap beginning in F2027 and a capacity gap beginning in F2021 without Expected LNG load
- The corresponding energy and capacity gaps begin in F2022 and F2020, respectively, with Expected LNG load

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

1. Pre-COD EPAs where there is some ability to defer COD, downsize capacity or terminate the EPA
2. EPA renewals where contracts are coming to end of life
3. New EPAs

For all three categories, as described in section 4.2.5.1, projects were assessed based on cost, implementation risk, system benefits and economic development benefits.

8.2.4.2 Execution

Termination of Pre-COD EPAs: To date, BC Hydro has executed mutual agreements to terminate four EPAs, representing 147 MW in nameplate capacity and 980 GWh in total annual generation (prior to attrition adjustment). BC Hydro is in discussions with IPPs where development of pre-COD EPA projects has stalled, with the objective of obtaining mutual agreement to terminate these contracts.

EPAs where there is some ability to manage additional supply: BC Hydro is continuing to discuss options for deferral or downsizing of EPAs with developers, where feasible options exist.

EPA Renewals: As described in section 4.2.5.1, prior to this IRP BC Hydro assumed that no bioenergy EPAs would be renewed upon expiry due to pricing and fuel supply risks, and that all other EPAs would be renewed for the remainder of the planning horizon. For planning purposes, BC Hydro now assumes that about 50 per cent of the bioenergy EPAs will be renewed, and about 75 per cent of the run-of-river hydroelectric EPAs that are up for the renewal in the next five years will be renewed. These EPA renewal planning assumptions would result in about 1,800 GWh/year of firm energy in F2021 and about 6,400 GWh/year of firm energy in F2033.

However, IPP projects will be individually assessed as EPAs come up for renewal. BC Hydro recognizes that EPAs can provide beneficial products such as voltage support, dependable capacity (valued using Revelstoke Unit 6 cost of capacity) and dispatchability. A recent example is BC Hydro's plan to exercise an option to extend the EPA term for the 120 MW McMahon Cogeneration natural gas-fired facility located near Taylor, B.C., provides cost-effective firm energy, dispatchability and capacity support to the local transmission system. Consultation with First Nations would be required where there are physical or operational changes to the projects triggered by the renewal.

By way of illustration, renewing about 2,000 GWh/year by F2021 would cost about $2.5 billion (through to F2033 in as spent dollars).

New EPAs: BC Hydro modified various SOP rules and made changes to the Standard EPA to re-affirm the original spirit and intent of the program. These changes are expected to result in energy supply reductions on a planned basis. For example, on March 26, 2013 BC Hydro amended the SOP rules to: limit the participation of clustered projects that exceed 15 MW; better manage when SOP energy supply comes on-line by maintaining flexibility to extend CODs for projects by up to two years; and extend the wait period for projects with terminated EPAs from three years to five years as a deterrent to opportunistic behaviour with respect to EPA pricing and other terms and conditions. In addition, this increased waiting period will be better aligned with the timing for when new energy resources are required. BC Hydro is continuing to negotiate in good faith with First Nations and other parties where agreements are in place committing BC Hydro to negotiate EPAs.

8.2.4.3 Future Approval Process

BC Hydro anticipates that its management of the IPP EPA portfolio will be scrutinized as part of the cost of energy in the F2015/F2016 RRA proceeding in 2014.

8.2.5 Recommended Action 5: Customer incentive mechanisms

Investigate incentive-based pricing mechanisms over the short-term that could encourage potential new customers and existing industrial and commercial customers looking to establish new operations or expand existing operations in BC Hydro’s service area.

8.2.5.1 Justification

Because domestic rates are higher than the price that can be obtained on the spot market, one potential strategy to get higher value for the available energy is to increase domestic demand. This is only worthwhile if the increased load is temporary and there is benefit in the initiative. Initiatives that boost demand over a longer timeframe will increase rates and revenue requirements once the additional electricity supplies are needed.

8.2.5.2 Execution

To date, BC Hydro has focused on identifying potential incremental loads from existing Transmission Service Rate (**TSR**) customers, which is currently approximately 300 GWh/year. Going forward, BC Hydro will identify potential new customer loads. Section 4.2.5.4 identifies the various design considerations that would need to be considered.

8.2.5.3 Future Approval Process

The future approval process depends on the implementation mechanism:

- Stand-alone legislation: Precedents include the B.C. *Power for Jobs Development Act*[7] which specifically provided that the BCUC did not have jurisdiction in respect of the ‘development power rates’ offered by BC Hydro. Under the *Power for Jobs Development Act* an administrator was appointed to determine if there was surplus energy and to review applications from an economic, environmental and societal interest perspective.
- Programs/contracts under section 9 of the *CEA:* Use of this mechanism requires Cabinet regulation
- A tariff to be filed with the BCUC pursuant to sections 58 to 61 of the *UCA*: The BCUC has broad discretion to determine if a rate is just, reasonable, not unduly discriminatory and/or not unduly preferential. A tariff may not permit tailoring for particular customer circumstances.

7 S.B.C. 1997, c.51.

8.2.6 Recommended Action 6: Continue to advance Site C

Build Site C to add 5,100 GWh/year of annual energy and 1,100 MW of dependable capacity to the system for the earliest in service date of F2024 (for all six generating units) subject to: environmental certification; fulfilling the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and Provincial Government approval to proceed with construction.

Site C consists of the development of a proposed third dam and hydroelectric generating station on the Peace River in northeast B.C. Site C would be the third project downstream of BC Hydro's existing generating facilities at GM Shrum (**GMS**) and Peace Canyon and the respective Williston and Dinosaur reservoirs. Site C would be publicly owned and would become one of BC Hydro's Heritage Assets.

Site C triggers *B.C. Environmental Assessment Act (**BCEAA**)* and *Canadian Environmental Assessment Act* (***CEAA***).[8] Site C is currently in a harmonized federal-provincial environmental review,[9] which includes a Joint Review Panel (**JRP**) process. The environmental assessment process for Site C started in August 2011 and is anticipated to take approximately three years to complete. Details concerning the harmonized federal-provincial environmental review are provided below.

Site C earliest in service date is F2024 for all six generating units, with the first power from Site C in late F2023. An in service date of F2024 is considered reasonably achievable, subject to environmental certification; fulfilling of the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and Provincial Government approval to proceed with construction. BC Hydro has also

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[8] The Executive Director of the EAO issued a section 10 *BCEAA* order on August 2, 2011, determining the Site C is a reviewable project pursuant to Part 4 of the B.C. *Reviewable Projects Regulation*, B.C. Reg. 370/2002; the Agency determined on September 30, 2011 that the requirements to commence an environmental assessment under *CEAA* had been met.

[9] A joint Agreement to Conduct a Cooperative Environmental Assessment, Including the Establishment of a Joint Review Panel, of the Site C Clean Energy Project between the Minister of Environment, Canada and the Minister of Environment, British Columbia was issued on September 30, 2011 after a public comment period, and amended on February 13, 2012.

included a F2026 in service date to provide a basis for evaluation in Chapter 6 of this IRP.

The final cost estimate for a capital project can only be known after a competitive procurement process is complete and final bids for construction contracts are accepted. Due to engineering, environmental and consultation work done in Stages 2 and 3 (described below in section 8.2.6.1), Site C has reached an advanced level of project definition. The Site C cost estimate of $7.9 billion is commensurate with a Class 3 cost estimate according to the estimating practices of the Association for Advancement of Cost Engineering (**AACE**),[10] as compared to the majority of other IRP resource options that are based on lower accuracy Class 4 or 5 estimates. As described below in section 8.2.6.2, the Site C cost estimate includes adjustments for inflation and the cost of financing during construction, and has undergone both internal and external review.

8.2.6.1 Justification

Need – There is a need for Site C based on the LRB analysis in Chapters 2, 4 and 6 even after taking into account the pursuit of the DSM target set out in Chapter 6. With the implementation of the DSM target and EPA renewals, new resources are required to meet the energy and capacity needs of BC Hydro’s customers:

- There is an energy gap beginning in F2027 and a capacity gap beginning in F2021 without Expected LNG load
- The corresponding energy and capacity gaps are F2022 and F2020 respectively with Expected LNG load

[10] As defined in AACE Recommended Practice No. 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Hydropower Industry (revised January 25, 2013), page 9 of 14. The BCUC requires Class 3 cost estimates for CPCN applications; refer to section 5 of the BCUC’s 2010 *Certificate of Public Convenience and Necessity Application Guidelines* (BCUC Order No. G-50-10, March 19, 2010).

It is difficult to precisely time the addition of any new electricity resource with the exact year of forecasted energy or capacity gaps, particular large hydroelectric facilities such as Site C. There are a number of uncertainties that could result in higher or lower customer demand, and lower or higher resource delivery, including:

- **Load Forecast Variability:** BC Hydro's Load Forecast is sensitive to a number of variables, including economic conditions. Factors that can lead to a lower load than forecast include a reduction in the growth in China and elsewhere, leading to a slowing of commodity demand and lower prices. Factors that can lead to higher than forecast electricity sales include strengthening world demand for commodities and electrification;
- **Expected LNG Load:**. BC Hydro has considered an Expected LNG load of 3,000 GWh/year and 360 MW within an overall range of about 800 GWh/year to about 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand;
- **DSM Delivery Risk:** The current DSM target is a significant step up from DSM targets BC Hydro pursued prior to the 2008 LTAP. The consequences of DSM not delivering the anticipated capacity savings are of particular concern because while generally external markets can be counted on for supply of energy across the year (albeit with costs), during winter peak periods there are issues with: 1) the illiquid (thinly traded) nature of the market for capacity; 2) insufficient transmission capacity; and 3) the U.S. market potentially not having surplus to sell.

These uncertainties underscore the need to review a range of future resource requirements, rather than solely single point estimates for LRB energy and capacity gaps.

BC Hydro examined a number of sensitivity cases: 1) large gap (i.e., high load growth with low DSM savings level) and small gap (low load growth with low DSM savings level); 2) high and low market price scenarios; 3) a lower cost of capital assumption for IPP projects; 4) higher capital costs for Site C; and 5) different wind integration costs. In general, these sensitivities result in a present value advantage for Site C as compared to viable alternatives in all except in:

- The small gap scenario, which is a low probability scenario (10 per cent) that would effectively see negligible load growth after DSM for the relevant portion of the planning period (about 4,000 GWh net growth from F2024 to F2033)
- The low market price scenario, which is a low probability scenario (20 per cent), with a F2024 in-service date when compared to the Clean + Thermal Generation Portfolio
- The scenario where Site C’s capital cost is increased by 10 per cent

BC Hydro considers it prudent to continue to proceed with Site C for its earliest in service date of F2024 given these uncertainties and present value results. Detailed discussion of the timing for the need of Site C to meet load requirements is provided in section 6.4.2.

Cost-Effectiveness: Resources that are viable alternatives to Site C in various combinations are: 1) DSM Option 3; 2) clean or renewable energy: wind, run-of-river, biomass; 3) clean or renewable capacity – Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and pumped storage facilities; and 4) natural gas-fired generation within the *CEA* 93 per cent clean or renewable parameter. All Site C and viable alternative portfolios assumed as a baseline condition achievement of BC Hydro’s DSM target:

- **DSM Option 3:** On its own, DSM Option 3 is not an alternative to Site C and needs to be combined with other clean or renewable alternatives or natural gas-fired generation. Site C is cost-effective against portfolios with DSM Option 3 and clean or renewable alternatives or natural gas-fired generation.

- **Viable clean or renewable alternatives:** Site C has a lower unit energy cost (**UEC**) at about $94/MWh[11] than clean or renewable resources which for a comparable Clean Generation block of 5,100 GWh/year of firm energy have a UEC of about $153/MWh. Site C is a cost-effective resource for both the F2024 and F2026 ISDs when compared on a present value basis to Clean Generation Portfolios in all but the small gap sensitivity and where Site C's capital cost is increased by 10 per cent.
- **Natural gas-fired generation:** Site C's UEC of $94/MWh is lower than the UECs for the Clean +Thermal Generations blocks of $128/MWh (Revelstoke Unit 6 and six SCGTs) and $130/MWh (Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and four SCGTs). Site C is also a cost-effective resource when compared on a present value basis to portfolios containing natural gas-fired resources within the *CEA* 93 per cent clean or renewable parameter. As set out above, Site C has a minor cost disadvantage if built by F2024 when compared to the Clean + Thermal Generation Portfolio in a low market price scenario, in the small gap sensitivity and in a scenario where Site C's capital cost is increased by 10 per cent.

For more details refer to section 6.4.

Site C is a dispatchable resource, and provides ancillary benefits to the BC Hydro integrated system including shaping and firming, and wind integration capability. In contrast, generation from many viable clean or renewable resources such as wind or run-of-river are determined by environmental considerations such as wind speeds or seasonal river flows, and as a result, these intermittent resources cannot be economically dispatched in response to changes in market prices. For example, generation of run-of-river resources generally peaks in the spring and early summer when customer demand is lowest; facilities such as Site C which are downstream of

[11] UEC excluding sunk costs, adjusted to the Lower Mainland before taking into account a capacity credit. The corresponding UEC after a capacity credit is $83/MWh.

large hydroelectric storage reservoirs can be operated to have lower generation during the spring and early summer allowing run-of-river generation to be used to serve load as much as possible. Some of these additional benefits are not captured in the present value analysis, further discussion of these additional benefits is provided in section 6.4.5.

Environmental and Economic Development Attributes: The environmental footprint analysis provided no basis to rethink BC Hydro's current actions regarding Site C. The economic development impacts of the Site C portfolio analysis show that portfolios including Site C provide higher amounts of Provincial gross domestic product (**GDP**) and employment. Detailed discussions of environmental and economic development attributes are included in section 6.4.4 and 6.4.5 respectively.

8.2.6.2 Execution

BC Hydro adopted a multi-stage approach for the planning and evaluation of Site C given the long lead time and the scope of evaluation and development work required for a major hydroelectric facility. This approach provides multiple decision-making points during project development, and focuses on specific deliverables and objectives at each stage:

- Stage 1, Review of Project Feasibility, took place from 2004 to 2007. The review concluded that it would be prudent to continue to investigate Site C as a potential resource option to address the electricity supply gap within BC Hydro's service area.
- BC Hydro moved to Stage 2, Consultation and Technical Review, following direction by the B.C. Government in the 2007 Energy Plan. Stage 2 included consultations with Aboriginal groups, the public and stakeholders, as well as advancing environmental studies, field studies, engineering design and technical work. Based on Stage 2 key findings, BC Hydro recommended

proceeding to the next stage of project planning and development, including an environmental and regulatory review.

- BC Hydro entered Stage 3, the Environmental and Regulatory Review stage, in April 2010, following a decision by the B.C. Government to advance the project to the next stage of development. Stage 3 includes an environmental assessment process by federal and provincial regulatory agencies.
- Should BC Hydro receive environmental certification at the end of Stage 3 for Site C, Stage 4 would include a decision by the BC Hydro Board of Directors and the B.C. Government to proceed to full project construction.
- Stage 5, Construction, is the final stage, involving an approximately seven-year construction period, with one additional year for final project commissioning, site reclamation and demobilization.

As part of Stage 3, the Site C project is undergoing a harmonized environmental assessment by lead by the Agency and the Environment Assessment Office (**EAO**), which includes a JRP process. The environmental assessment process commenced in August 2011 and is anticipated to take approximately three years to complete. The environmental assessment process for Site C includes several public comment periods, as well as public hearings under a JRP.

Milestones of the environmental assessment process for Site C to date include:

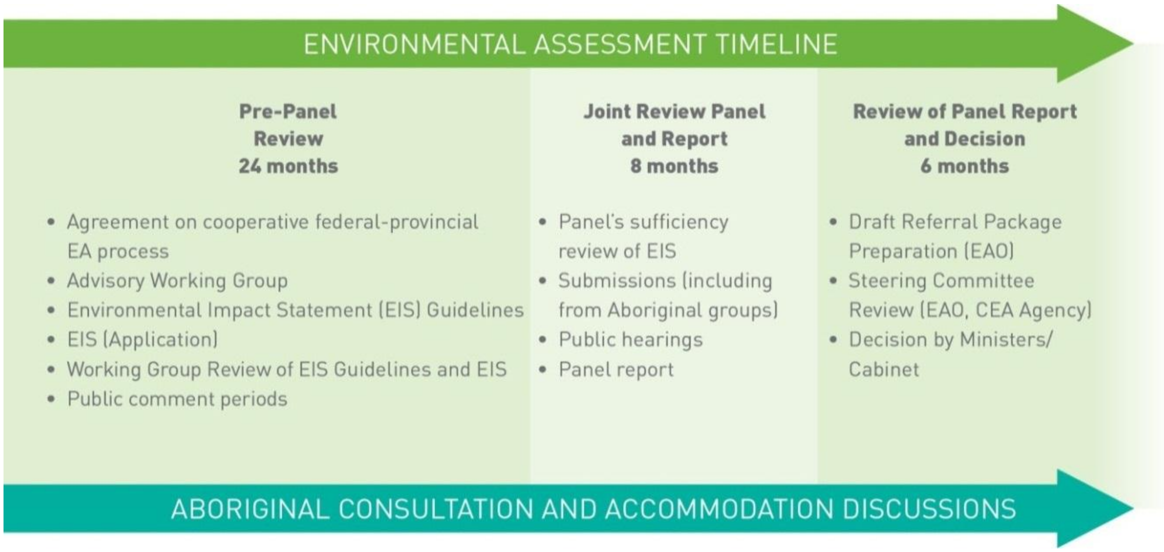
- **May 2011:** BC Hydro initiated the environmental assessment process by submitting a Project Description Report to the Agency and the EAO
- **August 2011:** The Project Description Report was formally accepted by the Agency and EAO, which commenced the formal environmental assessment process
- **September 2011:** A draft agreement was released by the federal and B.C. Ministers of Environment for a harmonized environmental assessment of

Site C, including a JRP process. The agreement was subject to a 30-day public comment period.

- **February 2012:** The agreement for a harmonized environmental assessment of Site C was finalized by the regulatory agencies in February (and amended following the implementation of *CEAA 2012*). This agreement provided guidance on expected timing for each review stage
- **April 2012:** Draft Environment Impact Statement (**EIS**) Guidelines for Site C were issued by the Agency and the EAO for a 45-day public comment period, which included open house sessions in key communities in northern B.C. and Alberta
- **September 2012:** Final EIS Guidelines were provided to BC Hydro by the Agency and the EAO. The EIS Guidelines set out the information that must be included in the EIS for Site C.
- **January 2013:** The Site C EIS was filed with Agency and the EAO. The EIS is a detailed report of potential environmental, economic, social, health and heritage effects of Site C and, where effects cannot be avoided, it identifies options for mitigation. The report also includes a review of the need for Site C and analysis of potential alternatives to and benefits of the project.
- **February/March 2013:** The Site C EIS was issued for a 60-day public comment period, which included open house sessions in key communities in northern B.C. and Alberta
- **July 2013:** The Amended EIS, reflecting changes requested by the Agency and EAO, was filed with the Agency and the EAO

Figure 8-1 provides a high level summary of the process. Based on the schedule provided by the environmental assessment agencies, the process is expected to be completed in the fall of 2014.

Figure 8-1 Environmental Assessment Process



Risk Mitigation

BC Hydro has reviewed the key project risks and has mitigation strategies in place for each risk identified, as summarized in Table 8-11 below.

Table 8-11 Key Project Risks and Risk Management

Risk: Regulatory Schedule	
Description	**Risk Management**
The regulatory process and schedule for Site C is determined by the federal and provincial regulatory bodies, and may be subject to changes in schedule and/or scope.	Prior to commencing the formal environmental assessment process, BC Hydro undertook project definition work, early environmental studies and other work to determine whether it was prudent to proceed to the environmental assessment stage. This work also included the establishment of several Technical Advisory Committees on key regulatory topics to consult with regulatory bodies and stakeholders regarding the potential scope of required studies. This preparatory work enabled some anticipation of the requirements of the environmental assessment process, and mitigates the risks of a process delay. Site C is now undergoing the formal environmental assessment process. In February 2012, the federal and provincial governments announced that an agreement had been finalized for a harmonized environmental review of Site C. This agreement identified defined timelines associated with the key steps of the environmental assessment process. To date, these defined timelines have been met and the regulatory process is on schedule.

<table>
<tr><th colspan="2">Risk: Achieving Accommodation Agreements with First Nations, where appropriate</th></tr>
<tr><th>Description</th><th>Risk Management</th></tr>
<tr><td>The Crown has a duty to consult, and where appropriate, accommodate Aboriginal groups.</td><td>BC Hydro and Aboriginal groups are engaged in consultation and engagement processes that will continue through all stages Site C. To date, BC Hydro has engaged approximately 50 Aboriginal groups in B.C., Alberta, Saskatchewan and the Northwest Territories.

BC Hydro has concluded 13 consultation agreements representing 16 First Nations to date. Others remain under discussion. Consultation activities include:
• Providing access to and facilitating an understanding of project-related information, including but not limited to the need for and alternatives to Site C;
• Identifying and understanding the issues, interests and concerns brought forward by Aboriginal groups about Site C;
• Creating opportunities to receive input from Aboriginal groups into the planning, design, construction and operation of Site C;
• Acquiring, considering and incorporating traditional land use information;
• Facilitating participation in the environmental assessment process through provision of capacity funding and access to technical expertise as it relates Site C;
• Negotiating IBAs where appropriate;
• Identifying potential training, employment, contracting and broader economic opportunities related to the project that may be of interest to Aboriginal groups or individuals.</td></tr>
<tr><th colspan="2">Risk: Project Design</th></tr>
<tr><th>Description</th><th>Risk Management</th></tr>
<tr><td>New technical information could require a change in project design or construction.</td><td>BC Hydro undertook significant site investigation work in the design phase of the project. This allowed BC Hydro to characterize ground conditions for design and construction purposes.

As a result of these investigations and associated engineering work, the project design has been upgraded from the historical project design to meet current seismic, safety and environmental guidelines. The project design for Site C is robust and capable of meeting unexpected conditions. Key design upgrades have resulted in improved foundation stability, greater seismic protection, enhanced spillway safety and additional generating capacity.

In keeping with BC Hydro and international practice for major projects, an external technical advisory board composed of global experts in hydroelectric development reviewed and provided feedback on BC Hydro’s design choices for Site C.</td></tr>
</table>

Risk: Project Costs	
Description	**Risk Management**
There is the risk of additional costs or delays during the construction phase.	Due to engineering, environmental and consultation work done in Stages 2 and 3, Site C has reached an advanced level of project definition. As a result, the $7.9 billion project cost estimate is at a higher level of accuracy than previous estimates (the Site C cost estimate is a Class 3 cost estimate). BC Hydro is utilizing project management and project control methods to deliver the project within this mandate. The Site C cost estimate includes contingencies (18 per cent on direct construction costs and 10 per cent on indirect costs, excluding some costs in reserves). This an appropriate level of contingency given the level of uncertainty in future conditions. BC Hydro's capital cost estimate for Site C has undergone an external peer review by KPMG, which determined that the methodologies and assumptions used in the cost estimate are appropriate. The project procurement approach has been designed to, among other things, efficiently allocate and manage project risks to reduce the likelihood of construction cost overruns or delays.
Risk: Labour	
Description	**Risk Management**
Availability of labour could be constrained during the construction period.	BC Hydro is working with contractors, employers, educational institutions, local and Aboriginal community groups, employment agencies and related organizations to advance initiatives to secure an available supply of qualified local workers. Some examples of initiatives aimed at providing local labour opportunities include undertaking skilled trades capacity building. Examples of capacity building include providing $1 million to support trades and skills training at Northern Lights College, and other contributions aimed at attracting new entrants into trades training. The Site C cost estimate includes an appropriate level of contingency to reflect uncertainty in future conditions.

8.2.6.3 Future Review Process

Environmental Assessment: As described above, Site C is nearing completion of the pre-JRP stage of the harmonized federal-provincial environmental assessment process. A large number of federal, provincial and local government permits and approvals will be required during the construction and operational phases of Site C, including authorization from Fisheries and Oceans Canada pursuant to sections 32 and 35(2) of the Canada *Fisheries Act*.[12]

BCUC: BC Hydro is exempt from any requirement to obtain a Certificate of Public Convenience and Necessity (**CPCN**) for Site C pursuant to subsection 7(1)(d) of the *CEA*. BC Hydro anticipates that the costs for Site C would be amortized over a long period. This amortization period and rate impact would be determined through a future regulatory process with the BCUC.

8.2.7 Recommended Action 7: Pursue bridging options for capacity

Fill the short-term gap in peak capacity with cost-effective market purchases first and power from the Columbia River Treaty second.

Site C is expected to be available by F2024. There is a three-year capacity gap without Expected LNG load from F2021 to F2023. BC Hydro proposes to rely on the market, backed up by the Canadian Entitlement provided under the Columbia River Treaty, for up to about 200 MW to meet any system capacity shortages during this period because the reliance is for a short period and because the market/Canadian Entitlement is cost-effective as compared to B.C.-based capacity resources that could be in-service by F2021 and would only be needed for about three years.[13]

However, there is uncertainty with respect to the Canadian Entitlement. While the Columbia River Treaty has no termination date, either Canada or the U.S. can unilaterally terminate most of the provisions of the Columbia River Treaty any time after September 16, 2024, providing at least 10 years' notice is given. In addition, planning to rely on the market for the three-year F2021 to F2023 period does not meet the self-sufficiency requirement set out in subsection 6(2) of the *CEA*. Lieutenant Governor-in-Council (**LGIC**) authorization is required.

[12] R.S.C. 1985, c.F-14.

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

For Expected LNG load, BC Hydro would advance natural gas-fired SCGTs for the North Coast in a staged and flexible manner as back-up for transmission outages and reliability. Refer to section 8.3.2.

8.2.7.1 Justification

Relying upon the markets and the Canadian Entitlement as bridging resources for up to about 200 MW for the three-year F2021 to F2023 period is beneficial for BC Hydro's ratepayers. The costs to maintain the market and Canadian Entitlement capacity options is lower than the alternative solutions of either building new natural gas-fired generation or Revelstoke Unit 6 solely for a three-year period before Site C's earliest ISD. The market and Canadian Entitlement capacity option-related costs are expected to be incidental business expenses.

8.2.7.2 Execution

To ensure BC Hydro has adequate capacity resources available to bridge to Site C, BC Hydro and Powerex will undertake two activities:

- Continue to monitor market conditions and U.S./Alberta transmission system development to facilitate and ensure that BC Hydro has access to up to about 200 MW of market purchases during all hours of the year and with a specific focus on BC Hydro's winter system peak load conditions
- Manage Canadian Entitlement, trade commitments and market optimization to about 200 MW of the Canadian Entitlement to be available to back up the 200 MW of market purchases

8.2.7.3 Future Approval Process

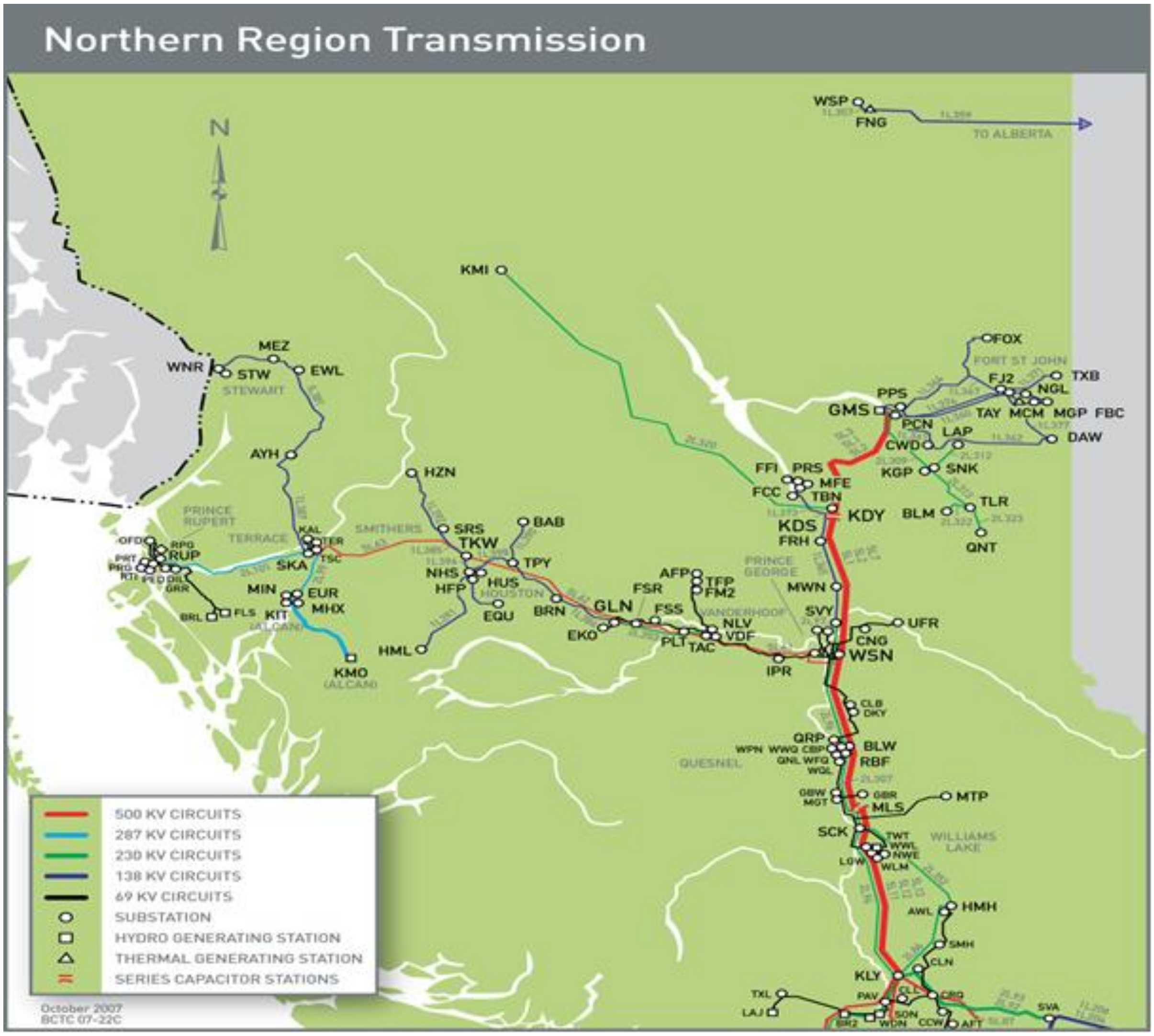
Relying upon the market and Canadian Entitlement for short-term capacity needs from F2021 to F2023 does not meet the self-sufficiency requirements in subsection 6(2) of the *CEA*. Subsection 6(3) of the *CEA* provides an exception to the self-sufficiency requirement found in subsection 6(2). The LGIC may by regulation authorize BC Hydro to enter into contracts for purposes of not meeting the self-sufficiency requirement.

8.2.8 Recommend Action 8: Advance reinforcement along existing GMS-WSN-KLY 500 kV transmission

Advance reinforcement of the existing GM Shrum-Williston-Kelly Lake 500 kV transmission lines to be available by F2024.

The northern transmission system transmits power from the Peace River generating facilities (GMS) through the Prince George region (WSN) to connect with the Interior-to-Lower Mainland System at KLY near Clinton, B.C. Three parallel 500 kV transmission lines (with five segments – 5L1, 5L2, 5L3, 5L4 and 5L7) deliver power from GMS – WSN and three 500 kV transmission lines (5L11, 5L12 and 5L13) deliver power from WSN - KLY.

Figure 8-2 Northern Region Transmission



The available transfer capabilities (**ATC**) of the GMS-WSN and WSN-KLY transmission line segments (cut-planes) are expected to be exceeded by dispatch of power from the existing and new resources in the Peace River region. To provide adequate incremental transfer capabilities, these cut-planes have to be reinforced.

Non-wire upgrades contemplated include the addition of shunt compensation at WSN and KLY Substations and enhancing the series compensation at Kennedy (**KDY**) and McLeese (**MLS**) series capacitor stations. The shunt compensation is expected to add 580 MW to 650 MW to the total transfer capability (**TTC**), while the enhance series compensation are expected to add 630 MW to 750 MW to the TTC.

The cost to complete further study work over the next five years is estimated to be $5.0 million. BC Hydro will have a total cost estimate with a +35 per cent /-15 per cent accuracy range when the study work is completed. The transmission upgrades are planning level estimates and detailed analytical studies are required to finalize scope and cost.

8.2.8.1 Justification

In the various portfolios that were analyzed in Chapter 6 of the IRP, the need to reinforce the GMS-WSN-KLY transmission was either by non-wire upgrades or additional transmission lines. Portfolios were also analyzed both with and without Site C as a resource. The results indicate that for portfolios without Site C, the ATC of GMS-WSN-KLY transmission cut-planes will be exceeded by F2029 (with Expected LNG load) and by F2032 (without any potential LNG load) due to the need for new generating resources. In portfolios with Site C, the need for the non-wire upgrades advances from F2029 to F2024.

In the majority of cases, the incremental transfer capabilities of the non-wire upgrades is expected to push the need for new transmission lines in the GMS-WSN and WSN-KLY 500 kV corridors beyond the 30-year planning horizon. In a few remaining portfolios these lines will only be needed towards the end of the 30-year planning period. Given that the majority of the analyzed mid gap portfolios did not require a new transmission line on the GMS-WSN-KLY corridor, the non-wire upgrades are being recommended.

8.2.8.2 Execution

BC Hydro would initiate further studies to confirm scope and cost of the required non-wire transmission upgrades on the GMS-WSN and/or WSN-KLY cut-planes for a F2024 ISD.

8.2.8.3 Future Approval Process

Pursuant to BC Hydro's Capital Project Filing Guidelines, BC Hydro would apply for a CPCN from the BCUC pursuant to subsection 46(1) of the *UCA* if the cost of identified projects is greater than $100 million.

8.2.9 Recommended Action 9: Reinforce South Peace transmission

Review alternatives for reinforcing the South Peace Regional Transmission Network to meet expected load.

The recently approved Dawson Creek/Chetwynd Area Transmission (**DCAT**) project will enhance the transmission capacities in the Dawson Creek and Groundbirch sub-regions. Continued load growth in these and other areas encompassing the South Peace region indicate further regional transmission reinforcements are required. BC Hydro must continue to advance its current regional planning activity referred to as the Peace Region Electrical Supply (**PRES**) study[14] to confirm the preferred regional capacity addition alternative following DCAT.

8.2.9.1 Justification

Electricity demand in the South Peace area is growing due to natural gas exploration and development of the Montney shale gas basin. Over the next 10 years, annual load growth in South Peace is expected to be about 10 times that of the rest of BC Hydro's service area. DCAT will increase the N-0 transfer capability to Dawson Creek and Groundbirch areas to 400 MW. The available capacity is expected to diminish as a result of the growing demand in South Peace Region. Additional N-0 transmission capacity is expected to be required by F2019. As discussed in section 6.2 that the South Peace region is an area where the need to build small, redundant gas units as well as the need to operate gas-fired units is expected to result in transmission being the preferred supply option.

[14] PRES was formerly referred to as GDAT (GMS to Dawson Creek Area Transmission).

8.2.9.2 Execution

BC Hydro should complete Identification Phase studies to determine the preferred alternative for providing incremental transmission capacity in South Peace Region and secure a F2019 in service date for the identified upgrades. These studies would, among other things, identify and evaluate alternatives, including local natural gas-fired generation. These studies are expected to be completed by the end of F2014 at an estimated cost of $1.2 million. BC Hydro will have a total cost estimate with a +35 per cent /-15 per cent accuracy range when these studies are completed.

8.2.9.3 Future Approval Process

Pursuant to BC Hydro's Capital Project Filing Guidelines, BC Hydro would apply for a CPCN from the BCUC pursuant to subsection 46(1) of the *UCA* if the cost of identified projects is greater than $100 million.

8.2.10 Base Resource Plan Load-Resource Balances

The Recommended Actions identified in section 8.2.1 through to section 8.2.9 provide BC Hydro's BRP without Expected LNG load for meeting its current and future customers' electricity needs on a reliable and cost-effective basis. The BRP aligns with the *CEA* energy objectives.

The LRBs for energy and capacity after implementation of the BRP Recommended Actions are depicted in Figure 8-3 and Figure 8-4 respectively.

1 **Figure 8-3 Energy Load Resource Balance: BRP**

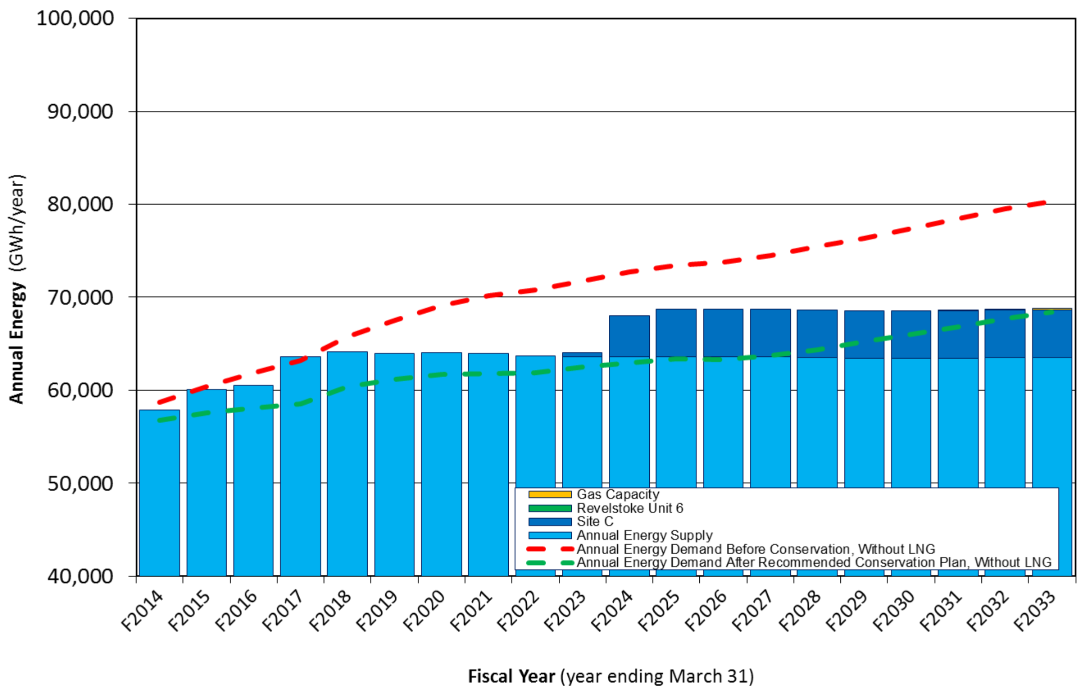
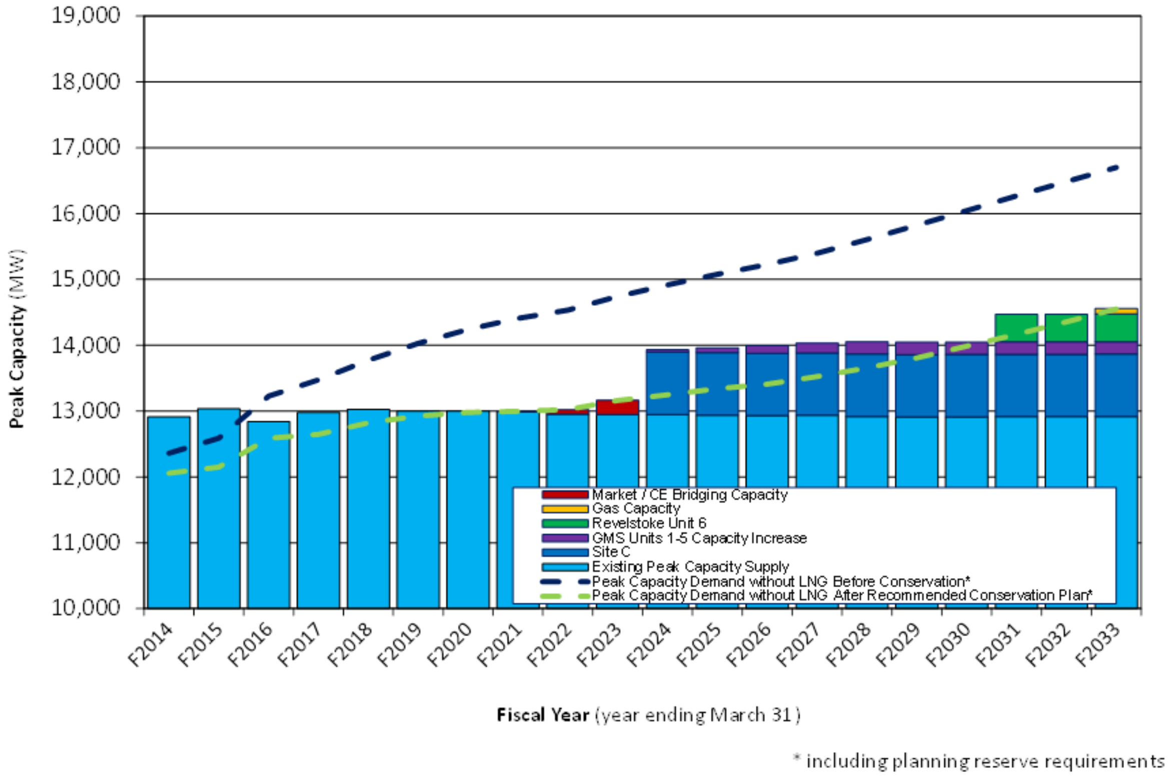


Figure 8-4 Capacity Load/Resource Balance: BRP



The BRP shows that the Recommended Actions will supply sufficient energy prior to Expected LNG to meet customers' needs past F2030 for energy, however, there will need to be additional capacity resources developed over the later stages of the F2020's. In bridging to Site C, about a 200 MW reliance on market/ Canadian Entitlement (**CE**) will be required and would be cost effective.

8.2.11 Long-Run Marginal Cost

BC Hydro uses the LRMC to signal the value that should be placed upon acquiring new resources which include: DSM savings; IPP EPA renewals; new IPP acquisitions; Resource Smart; Site C; and equipment efficiency and loss valuations. As the LRMC increases, the available supply from each of the resource types increases. This section highlights the LRMC based upon the BRP that will guide future processes and investments. Supplying the Expected LNG load will not have a material impact on the energy LRMC because BC Hydro has enough energy future processes and investments. Supplying the Expected LNG load will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve the Expected LNG load with the implementation of the BRP. Expected LNG would not likely materially impact the capacity LRMC because BC Hydro anticipates that the LNG-related need for incremental capacity will met by SCGTs, leaving Resource Smart projects such as Revelstoke Unit 6 as the marginal capacity resource.

8.2.11.1 Definition

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable. BC Hydro uses an approach where the incremental resource acquisitions needed to supply future requirements are stated on a levelized unit electricity cost basis to aid in comparing resources with differing attributes.

8.2.11.2 Setting the LRMC

Energy

Over the past 10 years, BC Hydro had a significant projected need for new resources and the marginal resource was the acquisition of greenfield clean or renewable IPPs. The LRMC reflected the results of the most recent, broadly-based power acquisition process (e.g., the Clean Power Call results). Using this benchmark a LRMC based upon greenfield clean or renewable IPPs would currently be $135/MWh. Greenfield clean or renewable IPPs were the marginal resource since there were insufficient cost-effective alternative resources available to provide the needed supply for customers that met the requirements of the *CEA*. This LRMC provided a price signal for BC Hydro to apply to all other resource options listed above.

Chapter 2 demonstrates there is a need for new B.C.-based resources in F2017 and that is why the energy LRMC is not based on spot market forecasts. Modifications to the self-sufficiency requirements and a lower load forecast have reduced forecasted need, and the next greenfield IPP clean or renewable energy acquisition is not expected within the planning horizon unless LNG needs exceed the 3,000 GWh/year expected amount. BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future needs including DSM, IPP EPA renewals, Resource Smart, Site C and equipment efficiency and loss valuations. The question becomes how much of these alternative resources need to be acquired to meet expected demand.

As DSM target summarized in section 8.2.10, the BRP LRB includes Site C, DSM Option 2 /DSM Target and the recommended IPP EPA management:

- As was shown in section 6.4, Site C is a cost-effective clean or renewable resource and if Site C were not constructed, additional greenfield clean or renewable IPPs would be needed. Site C's adjusted UEC is about $85/MWh. However, Site C is not a marginal resource because Site C is needed.
- BC Hydro tested varying levels of DSM in section 6.3 and demonstrated that DSM Option 2 was more cost-effective than DSM Option 3. Hence, not all DSM is being acquired and it is a marginal resource; e.g., incremental Option 3 DSM programs.
- In addition, the IPP EPA renewals that were analyzed in section 4.2.5.1 were cost-effective and were included in the LRBs. Any EPA renewals above planned assumptions would be marginal resources. As described above in section 8.2.4, BC Hydro expects to negotiate prices at or close to the spot

market price forecast but must consider factors such as the attributes to the energy product and associated non-energy benefits.

Thus DSM and EPA renewals are marginal resources up to F2033, after which BC Hydro would again require greenfield clean or renewable IPPs. In the process of developing and analyzing the IRP as discussed in Chapters 4 and 6, the LRMC was reduced from $135/MWh to $100/MWh. This reduced value informed the levels of DSM modelled and the upper price limit on IPP EPA renewals. It also informed what VVO savings to target as well as provided a price signal for internal equipment acquisition/ loss evaluation decisions. Depending on the amount of LNG load that BC Hydro ultimately serves and whether non-LNG load growth occurs as expected, the LRMC may be reduced to about $85/MWh and still provide an adequate supply of resources for expected load through to F2033.

Capacity

The LRMC for capacity resources when needed to augment the acquisition of energy and capacity resources is based upon Revelstoke Unit 6, which is lower cost than SCGTs. Revelstoke Unit 6 is being advanced as a contingency resource for its earliest in-service date, but is not expected to be needed in the BRP until F2031 and is the lowest cost avoidable capacity contingency resource. The UCC for Revelstoke Unit 6 is between $50/kW-year and $55/kW-year.

Energy and Capacity LRMC Summary

The LRMC outlook is as follows:

Energy:	$85/MWh-$100/MWh	F2017 to F2030.
Capacity:	$50-$55/kW-year	F2017 to F2030.

The energy and capacity LRMC relate to the cost of procuring energy and capacity, and include the costs of transporting that energy and capacity to the Lower Mainland, including line losses.

8.2.11.3 Energy LRMC Implications:

EPA Management

As described in Chapter 4, BC Hydro's EPA renewal planning assumptions are: 1) 75 per cent for small run-of-river project EPAs; 2) 50 per cent for bioenergy EPAs; and 3) 100 per cent for the remainder of EPAs. This results in about 4,700 GWh/year of firm energy from EPA renewals by F2024. As described above in section 8.2.4, BC Hydro should be able to benefit from depreciated assets by negotiating a lower energy price recognizing that the seller's opportunity cost is selling into the spot market. Section 5.6 of this IRP contains BC Hydro's reference (mid) spot market forecast of prices at Mid-C ranging from about $25/MWh to about $40/MWh over the next 20 years.

The spot market provides non-firm energy and no capacity, and generally has a term of one hour.[15] EPA renewals provide a different product than the spot market, including a longer contract term and in some cases dependable capacity, voltage support and dispatchability. Therefore there is likely to be some pricing up-lift from the spot market. BC Hydro is not likely to renew EPAs with a firm energy price greater than the LRMC.

DSM Plans

The IRP has recommended that the DSM target remain unchanged for F2021 at 7,800 GWh/year and 1,400 MW. The DSM plan that is recommended to achieve that plan is shown in section 8.2.1. Contained within that DSM plan are the three DSM tools (i.e., codes and standards, rates structures and programs), which are influenced by the LRMC:

[15] Market forward fixed-price contracts are available for terms of up to five years, with less liquidity in later years.

- The conservation rates utilize a two tier design of which the trailing step is influenced by the energy LRMC. As BC Hydro moves forward with its plans and rate design applications, the new LRMC will need to be considered.
- Programs are also influenced by the LRMC. Programs have the highest UC can be scaled down with the least long-term effects. As discussed in section 8.2.1, DSM programs will generally be designed in a manner consistent with the LRMC.

Other Resource Decisions

The other areas where BC Hydro will generally apply the LRMC include equipment purchases such as conductor sizing, transformer efficiency design and purchases, transmission voltage selection and VVO.

8.3 LNG Base Resource Plan

8.3.1 Recommended Action 10: Explore natural gas-fired generation for the north coast

Working with industry, explore natural gas supply options on the north coast to enhance transmission reliability and to meet expected load.

This Recommended Action would advance work to determine where and how natural gas-fired generation could be built in the North Coast to reduce project lead times and to be able to meet LNG load requirements as required. Acquiring SCGT generation on the North Coast would support system generating capacity needed to supply Expected LNG while supporting the transmission system in terms of enhanced reliability of supply and ability to operate during transmission outages for maintenance purposes.

8.3.1.1 Justification

The Prince George to Terrace Capacitor (**PGTC**) project (described in section 8.3.3 below) is expected to increase the transmission system to be capable of supplying the entire North Coast demand, including new non-compression LNG load, through the radial series compensated 500 kV transmission line that runs from Prince George to Terrace. The radial nature of the North Coast supply makes it susceptible to forced and planned outages of the 500 kV line. Currently, during an outage of the 500 kV line BC Hydro relies on local generation to supply a portion of the North Coast load in an islanded situation. Incremental load growth in the region is expected to exceed the islanding capability of the existing and committed North Coast supply in F2019.

The addition of SCGTs in the North Coast region would increase the capacity available to carry load in the North Coast through extended contingency and maintenance outages. The SCGTs would offset the need to build alternative generation in the system including potentially Revelstoke Unit 6. The use of natural gas-fired generation would increase the emission of GHGs, but is consistent with the British Columbia’s Energy Objectives Regulation. The decision on whether to proceed beyond exploring natural gas supply options to committing to build SCGTs would be pursuant to completion of supply agreements between BC Hydro and LNG proponents.

8.3.1.2 Execution

BC Hydro will conduct technical studies to determine the amount of SCGT capacity and ancillary services needed under various islanded operation scenarios. These studies will identify the technical requirements that will allow SCGT supply of the load during both forced and maintenance outages. Detailed project specifications will need to be completed by F2015 such that a subsequent competitive procurement process can be completed and facilities constructed and in-service by F2020, which coincides with the addition of the North Coast non-compression Expected LNG load. The technical studies are estimated to take one year to complete at an estimated cost of $0.5 million.

Assuming the technical studies confirm the need for natural gas-fired generation to support North Coast reliability levels, BC Hydro will conduct a competitive procurement process to enter into an agreement with a private developer to provide capacity and associated ancillary services, with BC Hydro able to call for services as required. BC Hydro will continue to work with potential developers to design a cost-effective and fair procurement process that will meet LNG ISDs. The design and execution of the procurement process is expected to take nine to 12 months to complete at an estimated cost of $1 million.

8.3.1.3 Future Approval Process

BC Hydro does not yet need to commit to the type and quantities of natural gas-fired generation required to maintain or enhance North Coast supply reliability. Expenditures for specific future resources will be contained in future RRAs or as part of EPA(s) filed with the BCUC pursuant to section 71 of the *UCA*.

8.3.2 Recommended Action 11: Explore clean or renewable supply options, if LNG demand exceeds available resources

Explore clean or renewable energy supply options and be prepared to advance a procurement process to acquire energy from clean power projects, as required to meet LNG needs that exceed existing and committed supply.

To ensure BC Hydro is prepared to meet both Expected LNG and potentially higher volumes of LNG load, BC Hydro will examine potential clean or renewable energy supplies that may be available both in the North Coast region and more generally in BC Hydro's service area. BC Hydro will also contemplate what processes and timeline it would have to follow to meet LNG proponent load requirements.

8.3.2.1 Justification

As shown in Chapter 2, BC Hydro has included a 3,000 GWh/year and 360 MW initial amount of load for Expected LNG. As discussed in Chapter 6, BC Hydro has sufficient energy to be able to supply Expected LNG without acquiring additional clean or renewable energy resources. However, given uncertainty as to potential LNG load and given that some LNG proponents have projected they could be in service by F2020, BC Hydro proposes to advance work on developing energy acquisition processes in a staged manner.

8.3.2.2 Execution

Over the next 12 to 24 months, BC Hydro will continue to monitor LNG proponent supply requirements and associated timing. Initial work on process development will include review of the most recent acquisitions and assessing what additional features may be required to meet LNG needs. Future LNG supply, as per the British Columbia's Energy Objectives Regulation and to ensure supplies will continue to make LNG proponents cost-effective, can be a mix of clean or renewable and natural gas fired generation. Exact supply mix would be determined as part of future customer supply negotiations between BC Hydro, the B.C. Government and LNG proponents.

BC Hydro will not launch an acquisition process until a clear need has emerged, however, BC Hydro will be prepared to meet LNG supply requests. Anticipated funding to ensure acquisition processes are ready to be launched as required range from $50,000 to $500,000.

8.3.2.3 Future Approval Process

The future approval of LNG related energy acquisitions will be determined by the supply contacts developed.

8.3.3 Recommended Action 12: Advance reinforcement of the 500 kV transmission line to Terrace

Advance reinforcement of the existing 500 kV transmission line from Prince George to Terrace, which includes development of three new series capacitor stations and improvements in the existing BC Hydro substations to be available by F2020.

The purpose of this project is to increase the transfer capacity of the existing 500 kV transmission circuit between WSN and SKA. The Prince George to Terrace Capacitor (**PGTC**) part of the reinforcement includes the building of three capacitor stations to be located along existing 500 kV transmission lines 5L61, 5L62 and 5L63 between WSN and SKA and providing voltage support to Glenannan Substation (**GLN**). In addition to PGTC a new 500/287 kV transformer (three 200 MVA units) at SKA is required.

8.3.3.1 Justification

The transmission PGTC upgrades are expected to increase the ability of the North Coast 500 kV transmission line to serve potential increased demand for electricity in northwest B.C. such as LNG Canada in the Kitimat area and potential mine load along the NTL corridor.

8.3.3.2 Execution

The PGTC project is currently in the Definition (preliminary design) phase. First Nations consultation and stakeholder engagement is taking place to assist with the selection and acquisition of appropriate sites for the capacitor stations. A detailed project plan will be developed for the Implementation phase of the project.

Progression into Implementation phase at this point will be dependent on the customer making a positive final investment decision, which is expected to occur by the end of F2015. BC Hydro’s estimated expenditures to this point and completion of Definition phase work are $2.8 million. The estimated cost of the PGTC project is $125 million with an accuracy of +35 per cent /-15 per cent. Detailed work related to addition of a new transformer at SKA has not yet begun. However, the transformer does not cause any expansion of the substation and is considered a low risk project with shorter duration than PGTC.

8.3.3.3 Future Approval Process

On March 25, 2013 the Minister issued Ministerial Order No. M073 entitled the *Transmission Upgrade Exemption Regulation*, which exempts BC Hydro from Part 3 of the *UCA* with respect to described transmission facilities, including series capacitor stations and related facilities and equipment and SKA transformer.

BC Hydro is in the process of consulting with First Nations with respect to PGTC.

8.3.4 Recommended Action 13: Horn River Basin and northeast gas industry

Continue discussions with B.C.'s northeast gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.

While the pace of expansion in the Horn River Basin (**HRB**) has slowed considerably over the past three to four years due to low gas prices and generally poor economic conditions, it is expected that gas prices will eventually recover to where this region will again develop. The emerging LNG industry in BC's northwest may be the driver for further development.

To maintain options to electrify this region to both facilitate development and potentially to manage GHGs that may be emitted, BC Hydro recommends that it continue to: monitor natural gas industry developments; engage with industry to keep open supply alternatives to Northeast B.C. and the HRB; and continue to support the B.C. Government in the development of its Climate Action Plan. Options include transmission connection to the integrated system and local gas-fired generation.

8.3.4.1 Justification

In F2013, BC Hydro concluded the Northeast Transmission Line (**NETL**) feasibility study work, which looked at the alternatives for extending electrical service to the natural gas industry in northeast B.C., including transmission connection to the integrated system and local natural gas-fired generation. That analysis is summarized in section 6.6 and provided as Appendix 2E and addresses the following questions:

- What actions are required to meet the load in Fort Nelson considering the solution for Fort Nelson may be influenced by the HRB industrial loads and supply options?
- What is BC Hydro's strategy to prepare for significant potential load growth in the combined Fort Nelson area and HRB region? What actions are prudent in the absence of load certainty?
- What approach should BC Hydro take to support provincial energy objectives on reducing GHG emissions via enabling electrification? This analysis considers the amount of CO_2 that is produced in the HRB under various gas production/energy supply scenarios and reduction opportunities.

Although the findings do vary based on market and pricing scenarios considered, the high level findings are:

- A combination of NETL and system clean or renewable energy strategy can reduce GHG emission by 30 to 38 per cent relative to industry business-as-usual (self-supply). However, this strategy is generally relatively more expensive than other strategies.
- Natural gas-fired generation strategies can reduce GHG emissions by 0 to 16 per cent relative to industry self-supply, but generally do not meet the 93 per cent *CEA* clean or renewable energy objective. Of the natural gas-fired generation strategies, co-generation appears to be the lowest cost option, but requires a good long-term balance and consistency of heat load and electric load as well as adequate addressing of commercial risks. BC Hydro-acquired co-generation shifts more GHG emissions to BC Hydro.

The analysis concludes the following:

- First and foremost, the HRB has significant, but uncertain electrification potential. Absent load certainty, all supply alternatives expose BC Hydro to different types and levels of stranded investment risk.
- There remains significant uncertainty with respect to industry's commitment to take electricity service
- Liability of vented formation CO_2 needs to be addressed; its inclusion and ownership will heavily influence both the scale of HRB development and the type of work supply alternative that would be most economic. With 70 per cent of total GHG emissions consisting of formation CO_2, meaningful emissions reductions will require carbon capture and sequestration (**CCS**)
- Lastly, in the absence of load certainty or having customers willing to fund the work it is premature to undertake significant supply actions in the near term to address the potential for large-scale electrification in the region

Given the potential GHG impacts and the *CEA* GHG related objectives, BC Hydro continues to work with industry on identification of potential future infrastructure requirements and opportunities for minimizing the region's overall future development footprint.

8.3.4.2 Execution

In line with the recommendation, BC Hydro is continuing to observe and monitor increased interest in electricity supply among gas producers operating in the northwest portion of the Montney Basin, i.e., Peace River region north of GMS. This region continues to experience increased levels of activity due to the characteristics of the gas resource and proximity to existing infrastructure. By comparison with the HRB, the gas resource in the northwest portion of the Montney Basin generally has better economics, it is richer in gas liquids (in the current price environment proceeds from sales of liquids help improve production returns) and has a lower CO_2 content. This region also encompasses the southern portion of the assumed NETL routing. BC Hydro will be working with these gas producers and other potential load customers to assess whether there is sufficient electrification potential to justify the need for a Phase 1 (southern portion) NETL project.

Resource requirements for these activities and other analysis will be primarily for external consulting support at an estimated cost of $50,000 to $100,000 over the next three years.

8.3.4.3 Future Approval Process

No material regulatory approval processes are envisioned at this time given the scope of the Recommended Action.

8.3.5 LNG Base Resource Plan Load-Resource Balances

The Recommended Actions identified in sections 8.3.1 through 8.3.4 provide BC Hydro's LNG BRP to supply Expected LNG load. They are aligned with the *CEA* objectives and support the government's LNG strategy and the development of the LNG industry.

The LRBs for energy and capacity after implementation of the LNG BRP Recommended Actions are depicted in Figure 8-5 and Figure 8-6 respectively.

Figure 8-5 Energy Load/Resource Balance: LNG BRP

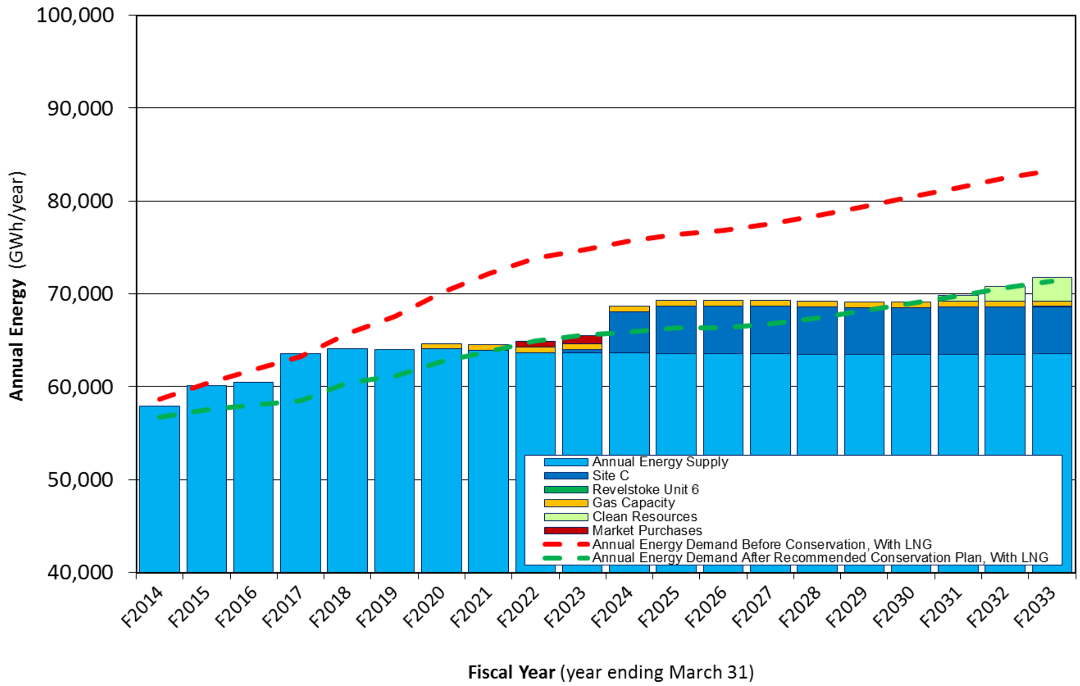
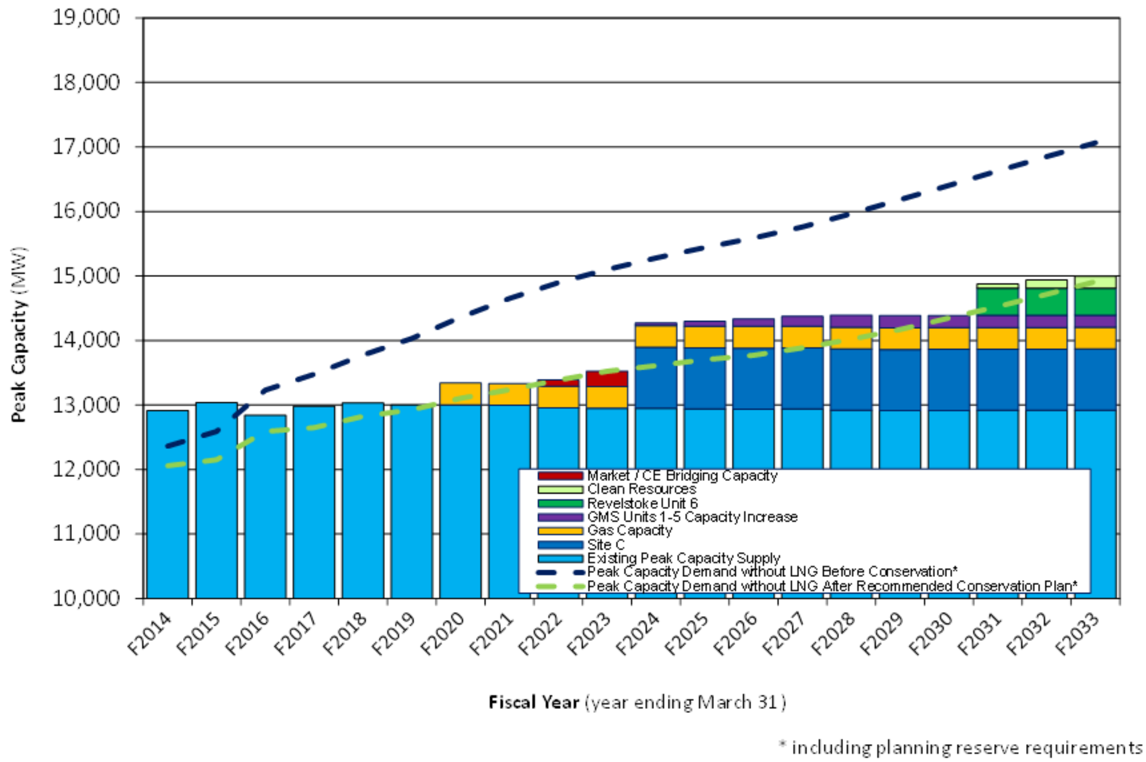


Figure 8-6 Capacity Load/Resource Balance: LNG BRP



The LNG BRP shows that the Recommended Actions will supply sufficient energy to supply Expected LNG needs through F2030, but additional LNG load would advance the need for energy resources. In particular, there are short-term needs prior to Site C that can be bridged with market/CE resources, but additional LNG load would drive the need for more energy acquisitions in the next 10 years. On the capacity side in the BRP there is a reliance of up to about 200 MW from the market backed by CE. In the LNG BRP the shortfall exceeds the degree to which market reliance is acceptable, about 580 MW. The additional resources to supply the incremental capacity need is expected to be about 400 MW of local gas generation which has an ability to support the regional transmission requirements. Towards the end of the F2020's, the need for new capacity is expected to drive the GMS and Revelstoke Unit 6 capacity additions.

8.4 Contingency Resource Plans

8.4.1 Contingency Planning

Contingency planning is done as a reliability management tool to manage the risk (consequences) of not being able to meet load by identifying alternative sources of supply that should be available should the BRP not materialize as expected. Contingency planning is part of good utility practice, and is a component of long-term resource planning recognized as important in the BCUC Resource Planning Guidelines.

As discussed in section 6.9.4.1, the key uncertainties that should be considered in developing contingency plans are load forecast uncertainty, DSM deliverability risk, and effective load carrying capability (**ELCC**) of clean or renewable intermittent resources. However, as concluded in section 6.9.4.3, the range of uncertainty captured by load forecast and DSM delivery uncertainties is considered sufficient to cover the ELCC uncertainty for the purpose of contingency planning. Generation and transmission capacity requirements are the primary concern since capacity is required to meet peak load requirements and maintain system security and reliability.

The process of creating CRPs is to contemplate the risk that BC Hydro would have an insufficient supply planned to meet its customers' needs and then to resolve how to recover and meet those needs. This is done through the creation of alternative portfolios of resources to meet the greater needs.

The aim of CRPs is not to build the resources in the portfolios but to reduce the lead time for supply-side resources and the required transmission to be placed in service if a need for them need arises. To minimize the costs of contingency plan actions, BC Hydro seeks to maintain ISDs by moving resources through the Identification and Definition phases of project development, incurring minimal costs and without committing to construction. If at some point lead time is insufficient to maintain the contingency resource and there is either sufficiently high likelihood the resource would be required or there is a high consequence of a supply shortage, BC Hydro would secure regulatory approvals (BCUC and/or environmental assessment related), as required, for its plan to construct the contingency resource initiating final Implementation.

BC Hydro submits CRPs to the BCUC for approval pursuant to the OATT and for the purposes of establishing a queue position for a transmission service request. The detailed BRP and CRP tables and graphs that would be the basis of the OATT submission provided to transmission planning are shown in Appendix 8A. CRPs are particularly important in light of the typically long lead times for transmission projects. The CRPs submitted to the BCUC must consider scenarios that reasonably test the transmission pathways that occur based on the possibility of resources and loads in specific locations. Without transmission planning formally including the CRPs in its planning processes and ensuring the associated transmission requirements are being maintained, BC Hydro's CRPs would be ineffectual.

As set out above, BC Hydro developed two CRPs: CRP1 addresses contingencies without Expected LNG load, and CRP2 addresses contingencies with Expected LNG load.

BC Hydro undertakes CRP planning separately for Fort Nelson given it is not interconnected to the BC Hydro integrated system. The resource requirements and transmission supply are unique and separate requirements. The Recommended Action related to the Fort Nelson CRP is shown in section 8.4.6 below.

The load forecast uncertainty (prior to LNG load) and DSM delivery uncertainty that are addressed by both CRP1 and 2 are as shown in Table 8-12 below.

Table 8-12 Contingency Resource Plan Shortfall Risks

Risk	Rationale	Capacity Reduction for CRP Purposes[16,17] (MW)		Energy Shortfall Risk (GWh/year)	
		F2017	F2033	F2017	F2033
General Load Forecast Uncertainty	Peak load and energy requirements can increase as a result of sustained growth and/or low temperatures at winter peak.	700	1,550	5,350	10,050
DSM Deliverability Uncertainty	The DSM target has a significant range of deliverability uncertainty where the variability is driven by implementation of codes and standards, customer response to programs and rates.	100	500	550	2,600
Total Reduction		800	2,050	5,900	12,650

The portfolios that were created for CPR1 and CRP2 are shown in sections 8.4.5 and 8.4.6, respectively.

The resulting actions of the 2 CRPs in terms of analysis for additional transmission requirements will be undertaken when the CRPs are approved by the BCUC and included in the network transmission plan. The generation actions driven by both CRPs are advancing Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and gas fired generation.

8.4.2 Recommended Action 14: Advance Revelstoke Unit 6 Resource Smart project

Advance the Revelstoke Generating Station Unit 6 Resource Smart project to preserve its earliest in service date of F2021 with the potential to add up to 500 MW of peak capacity.

[16] Section 6.9 discusses the ability of intermittent clean or renewable resources to impact the need for new capacity resources and concludes that they are only able to offset the need minimally.

[17] Deliverability risk around DSM capacity savings has been factored into the CRPs. This was performed by examining high, medium and low capacity factor scenarios for the residential, commercial and industrial sectors. Refer to Appendix 4B for a further description.

With Expected LNG, BC Hydro would have up to a 580 MW capacity shortfall over the four-year period (F2020 through F2023) prior to Site C's earliest ISD. Given the *CEA* self-sufficiency requirement and the uncertainty in load and DSM deliverability, BC Hydro proposes to advance Revelstoke Unit 6 through Definition phase activity incurring limited costs. Any commitment to construct Revelstoke Unit 6 would be informed by the following: (1) the outcome of the Site C environmental assessment review; (2) LNG proponent final investment decisions; (3) the assessment of the role of natural gas-fired generation for LNG reliability requirements; (4) any future unexpected peak load growth; and (5) any unanticipated reductions in DSM deliveries.

Revelstoke Unit 6 would add 488 MW of long-term (50+ years) dependable capacity to the BC Hydro system, while also providing operational and ancillary services including system shaping, operating reserves, load following and rotational energy required to support intermittent resources. The direct capital cost of Revelstoke Unit 6, in May 2012 constant dollars, is $340 million ($420 million loaded). BC Hydro will spend up to $7.2 million between F2014 to F2016 to ensure Revelstoke Unit 6 is available for its earliest ISD.

8.4.2.1 Justification

BC Hydro has two low cost, clean or renewable capacity options – Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase:

Table 8-13 Clean or Renewable Capacity Options

Option	MW	ISD	UCC
Revelstoke Unit 6	488	F2021	$50/kW-year
GMS Units 1-5 Capacity Increase	220	F2021-F2025 (one unit per year)	$35/kW-year

BC Hydro proposes to advance both Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase as CRP resources and decide at a later date which is the most cost-effective capacity option and should be built first.

Cost Effectiveness: Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase are the two lowest cost capacity options. The cost comparison of all available capacity resources is discussed in section 6.9.

Environmental Attributes: Revelstoke Unit 6 installation work will be contained within the existing footprint of Revelstoke Generating Station (**Revelstoke GS**), and therefore is expected to have minimal additional environmental impact.

Policy Alignment: Revelstoke Unit 6 does not emit GHGs, supports the *CEA* 93 per cent clean energy objective (*CEA* objective 2(c)) and meets the legislated self-sufficiency requirement in subsection 6(2) of the *CEA*.

8.4.2.2 Execution

Revelstoke Unit 6 is currently in the Identification phase with low development uncertainty and medium cost uncertainty of +50 per cent/-15 per cent. BC Hydro proposes to advance Revelstoke Unit 6 through Definition phase using a staged and flexible approach to incur limited costs. Limited cost activities include:

- Complete the process to obtain environmental approvals, including obtaining an Environmental Assessment Certificate (**EAC**) under *BCEAA* and a Water Licence to increase the maximum diversion rate by 3,000 cubic feet per second, and related environmental studies
- Consultation with affected First Nations and stakeholders
- Undertaking preliminary design of the project and associated transmission requirements
- Updating assessments of the benefits associated with Revelstoke Unit 6
- Initiation of a staged procurement process targeted for September 2014 with the issuance of a Request for Statements of Qualifications

Business risks include the *BCEAA* review of Revelstoke Unit 6, stakeholder engagement and First Nations consultation. Scope risk is limited since Revelstoke

Unit 6 is fairly well defined, is similar to Revelstoke Unit 5 that went into service in December 2010 and is to be located in the existing Revelstoke GS. A capacitor station is required on the 500 kV transmission line 5L98 between Vaseux Lake Terminal Station and Nicola Substation to increase the capacity of the transmission system in the Interior of B.C. While the capacitor station will serve all existing generation in the Southern Interior of B.C., Revelstoke Unit 6 would advance the need for the capacitor station by about 15 to 20 years under current planning assumptions.

8.4.2.3 Future Approval Process

Pursuant to subsection 7(1)(c) of the *CEA*, BC Hydro is exempted from sections 45 to 47 of the *UCA* (CPCN requirement). On April 11, 2013, the EAO determined that BC Hydro requires an EAC under *BCEAA*. Revelstoke Unit 6 does not trigger *CEAA* because the *Regulations Designating Physical Activities*[18] provide that the trigger for expansions to a hydroelectric generating station is that the expansion would result in an increase in production capacity (installed capacity) of: (1) 50 per cent or more; and (2) 200 MW or more. Revelstoke Unit 6 does not result in an increase of the installed capacity of Revelstoke GS of 50 per cent or more. The installed capacity of the existing Revelstoke GS with the installation of Revelstoke Unit 5 is about 2,480 MW.

8.4.3 Recommended Action 15: Advance GM Shrum Resource Smart Project

Advance Resource Smart upgrades GM Shrum Generating Station Units 1-5 with the potential to gradually add up to 220 MW of peak capacity starting in F2021.

As part of its continuous review of opportunities to cost-effectively upgrade existing hydroelectric generation stations, BC Hydro identified a potentially low cost capacity

[18] SOR/2012-147, section 3(b).

opportunity at GMS, a capacity increase of Units 1-5. GMS Units 1-5 Capacity Increase could provide about 220 MW of dependable capacity (about 44 MW per unit). GMS is located next to the W.A.C. Bennett Dam on the Peace River. GMS is one of BC Hydro's largest capacity generating stations (about 2,790 MW) and one of the most important components in the BC Hydro integrated system. The GMS Units 1-5 Capacity Increase conceptual level cost estimate (loaded) is about $104 million. F2015 to F2016 capital spending on GMS Units 1-5 Capacity Increase is forecasted to be between $700,000 to $800,000 to determine feasibility and other related Identification phase activities.

8.4.3.1 Justification

GMS Units 1-5 Capacity Increase potentially may have a lower UCC than Revelstoke Unit 6:

- The UCC for GMS Units 1-5 Capacity Increase is estimated to be about $35/kW-year. This is based on a conceptual-level cost estimate with a range of accuracy (+100 per cent/ -35 per cent)
- Revelstoke Unit 6 has a UCC of about $50/kW-year

BC Hydro must balance the timing for the need for dependable capacity, costs, the difficult scheduling and co-ordination issues if it were to implement GMS Units 1-5 Capacity Increase:

- There is extensive work underway and planned at GMS involving eleven different projects[19] on all ten generating units which impacts when BC Hydro

[19] The eleven projects are: (1) GMS Unit Transformer Replacement Phase 3 Replacement of Unit 4 13.8 kV to 500 kV step-up transformers; (2) GMS Units 1 to 5 Turbine Replacement - this project includes new turbine runners, wicket gates, wicket gate operating mechanisms, head covers and overhauling remaining turbine components; (3) GMS Station Service Rehabilitation
Generating station service providing power for plant controls, fire systems and all auxiliary system; (4) GMS Units 6 to 8 Capacity Increase Replacement of the iso-phase bus and unit circuit breaker on Units 6 to 8 to increase GMS capacity by 90 MW (30 MW per unit); (5) GMS Units 1 to 4 Rotor Pole Rehabilitation of original (1968) rotor winding; (6) GMS Fire Alarm System Replacement of system in this underground generating station; (7) GMS Fire Protection Piping Replacement; (8) GMS Generator Monitoring System Installation

could undertake GMS Units 1-5 Capacity Increase. It is not recommended from a construction coordination, resourcing and safety perspective to implement an additional Units 1-5 capacity increase project while this current capital work is underway inside of this operating facility. These projects are expected to complete in or about F2020.

- GMS Units 1-5 Capacity Increase could not realistically be started until the eleven GMS projects are largely concluded. The high volume of work and overlap of projects at GMS pose an elevated safety and reliability risk in this operating facility. This is a risk that is being managed through proper co-ordination of the work.

If this GMS capacity increase opportunity is pursued in the future, the earliest the additional capacity would be available is beginning in F2021 with the first unit installation and be complete in F2025 with the last unit installation. During the installation B.C. Hydro would need to consider how unit outages would impact existing peak supply at GMS. These considerations have been reflected in the LRBs in Chapter 8.

8.4.3.2 Execution

BC Hydro will continue to review both Revelstoke Unit 6 and GMS Units 1-5 Capacity Increase. BC Hydro proposes to advance GMS Units 1-5 Capacity Increase through Identification and Definition phase activity using a staged and flexible approach to incur minimal costs. A schedule for GMS Units 1-5 Capacity Increase project could be as follows:

- Identification phase: one-year minimum

Monitoring system to reduce the risk of turbine or generator failures by providing advanced warning. This project includes vibration monitoring (Units 6 to 10), shear pin monitoring (Units 6 to 10), rotor to stator air gap monitoring (Units 5 to 10) and on-line partial discharge activity monitoring (Units 1 to 10); (9) GMS Unit 7 and 8 Exciter Transformer Replacement - Replace the exciter transformers with transformers of a modified design; (10) GMS Units 6 to 10 Governor Control Replacement - Replace the governor controls with a modern, standardized control system; and (11) GMS Units 1 to 10 Control System Upgrade - Replace controls, alarms, and metering to provide automation and significantly enhanced troubleshooting capability.

- Definition phase: two-and-a-half-year minimum: GMS Units 1-5 Capacity Increase likely triggers *BCEAA*, and BC Hydro would apply for a CPCN from the BCUC. A new Water License may be required due to the current diversion limit at GMS, and an addendum to Peace River Water Use Plan may be required
- Implementation phase: approximately five years, with one unit being placed in service each year
- If the project was initiated in F2016, GMS Units 1-5 Capacity Increase construction would be timed to begin with the completion of the current projects and could be fully in service in F2025

8.4.3.3 Future Approval Process

Pursuant to BC Hydro's Capital Project Filing Guidelines, BC Hydro would apply for a CPCN from the BCUC pursuant to subsection 46(1) of the *UCA* if project cost is greater than $100 million. BC Hydro may require an EAC pursuant to *BCEAA* as the threshold for modifications to an existing hydroelectric facility is an increase in the nameplate capacity of 50 MW or greater.[20] However, BC Hydro received a section 10(1)(b) *BCEAA* determination that no EAC was required for GMS Units 6-8 Capacity Increase Project, which has a scope similar to GMS Capacity Increase. An additional Water License may be required. GMS Units 1-5 Capacity Increase does not trigger *CEAA* because the *Regulations Designating Physical Activities* provide that the trigger for expansions to a hydroelectric generating station is that the expansion would result in an increase in production capacity of: (1) 50 per cent or more; and (2) 200 MW or more. GMS Units 1-5 Capacity Increase does not result in an increase of the production capacity of GMS of 50 per cent or more. The production capacity of the existing GMS is 2,790 MW.

[20] Table 7, Column 1 of the B.C. Reviewable Projects Regulation, B.C. Reg. 370/2002.

8.4.4 Recommended Action 16: Investigate natural gas generation for capacity

Working with industry, explore natural gas supply options to reduce their potential lead time to in-service and to develop an understanding of where and how to site such resources, should they be needed.

This Recommended Action entails undertaking work to develop natural gas-fired contingency options that focus on reducing the lead time to ISDs and an understanding of where and how to site natural gas-fired generation in the province. Working with IPPs, this will involve identifying and exploring specific natural gas-fired capacity options and procurement processes, should they be needed.

8.4.4.1 Justification

Natural gas-fired generation is the default incremental capacity resource when no other cost-effective capacity resources are available. See section 6.9.

8.4.4.2 Execution

BC Hydro will explore and develop a shelf-ready competitive procurement process to select new natural gas-fired generation projects in B.C. This work will occur in advance of any commercial commitments and BC Hydro will focus activities on the analysis and resolution of key development risks, and commercial and process issues, to develop a credible procurement framework that could be quickly activated if loads occur. BC Hydro will review other North American jurisdictions where natural gas-fired capacity procurements have occurred in the last five years. The potential procurement process is targeted to be completed in F2014 to ensure this option to serve future loads, if they occur.

Some of the key considerations for analysis and design of the potential procurement will be: First Nations engagement and consultation; siting; access to fuel; optimal allocation risks; desired operational characteristics; required project viability;

developer strength; ensuring cost-effective pricing; treatment of associated energy; necessary lead times; and potential transmission investments.

Given that little to no greenfield natural gas-fired generation project development work has occurred in B.C. for the last 10 years, there are significant components in siting and development of natural gas-fired generation facilities that need to be scoped. Depending on the required lead times, BC Hydro may need to initiate procurement in F2015 to maintain new natural gas-fired generation projects as a credible option. This could involve BC Hydro developing and implementing a competitive process to enter into an agreement with one or more developers to evaluate feasibility, undertake various studies (such as geotechnical or environmental), undertake feasibility-level design and engineering work and develop a schedule and budget for the development of potential specific gas projects. Given the work may occur in advance of any load commitments, BC Hydro will be looking to sharing some of the cost of the work.

The risks for this Recommended Action are:

- The contingency capacity option is not maintained and BC Hydro is unable to meet future load. To ensure that these resource options are available, BC Hydro is committing adequate funds and effort to advance the plans/options. BC Hydro will engage IPPs early in the process to ensure realistic options are being developed.
- BC Hydro incurs significant costs to advance these options and they are not required. To minimize the cost risk, BC Hydro will seek to find a way to risk share with IPPs to develop the resources to a shelf-ready status and avoid committing to major expenditures prior to need being confirmed. BC Hydro would also implement clear commercial terms that provide a framework for BC Hydro to defer or discontinue further activities with proponents and projects if new emerging loads are deferred or do not proceed. Committing in advance

to project development regardless of viability, price or other terms is not in the interest of ratepayers.

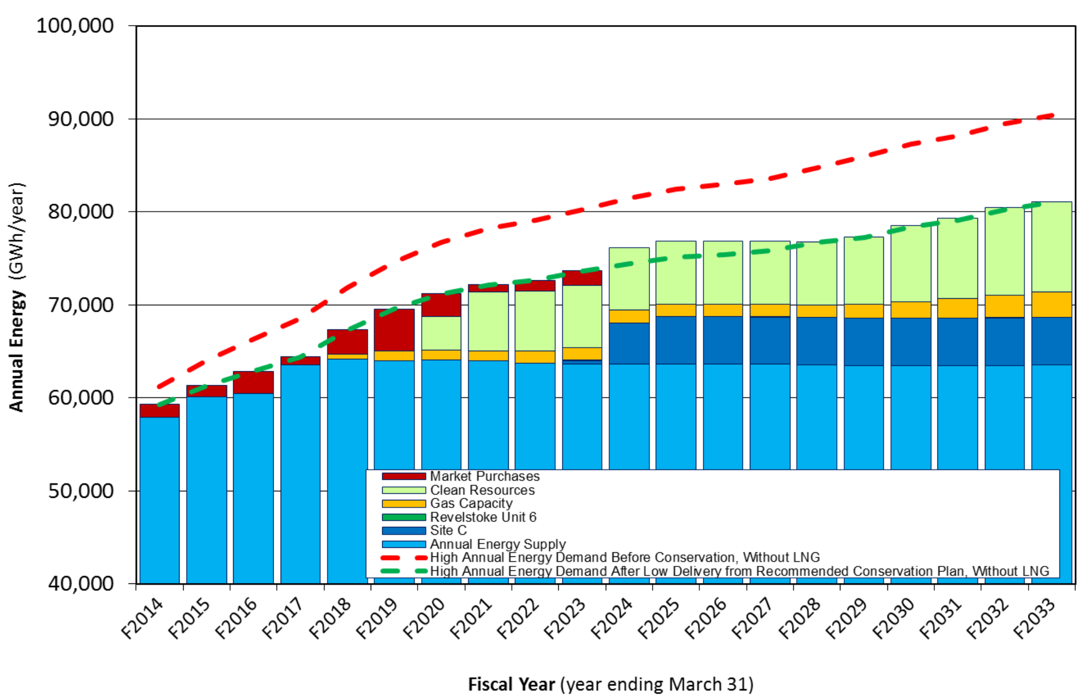
8.4.4.3 Future Approval Process

No approvals are required to explore natural gas-fired generation options and siting. If BC Hydro enters into any EPAs, the contracts would be filed with the BCUC under section 71 of the *UCA*. Individual natural gas-fired projects will likely trigger *BCEAA* as the threshold is a nameplate capacity of 50 MW or greater,[21] and will require air emission permits pursuant to the B.C. *Environmental Management Act*.[22]

8.4.5 CRP1

CRP1 results in the portfolio shown in Figure 8-7 and Figure 8-8.

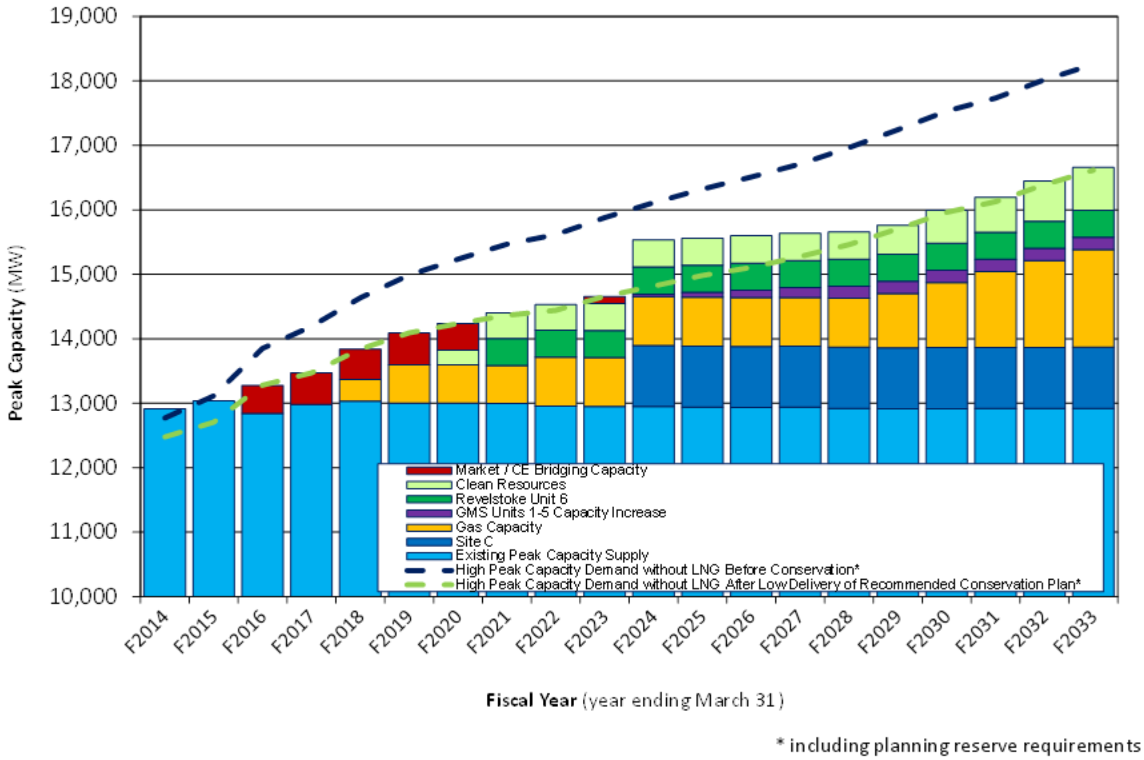
Figure 8-7 Energy Load/Resource Balance: CRP 1



[21] *Ibid.* Table 7, Column 2.

[22] S.B.C. 2003, c.53.

Figure 8-8 Capacity Load/Resource Balance: CRP 1



CRP1 shows how BC Hydro would plan to supply a high need for new resources. BC Hydro's main concern is to ensure adequate capacity is available to meet peak load requirements and to back up other generator forced outages. As discussed in section 6.9, the lowest cost capacity resources include Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and SCGTs, and these are built into this portfolio. If the higher gap occurs over a short timeframe, it is likely that some gas-fired generation would be required along with some market reliance.

While energy supply shortfalls are a lesser concern than capacity, CRP1 would likely drive the need to advance clean energy acquisitions.

8.4.6 CRP2

CRP2 adds Expected LNG to the loads that need to be supplied. The resulting portfolio that BC Hydro would plan to build is shown in Figure 8-9 and Figure 8-10.

1 **Figure 8-9 Energy Load/Resource Balance: CRP 2**

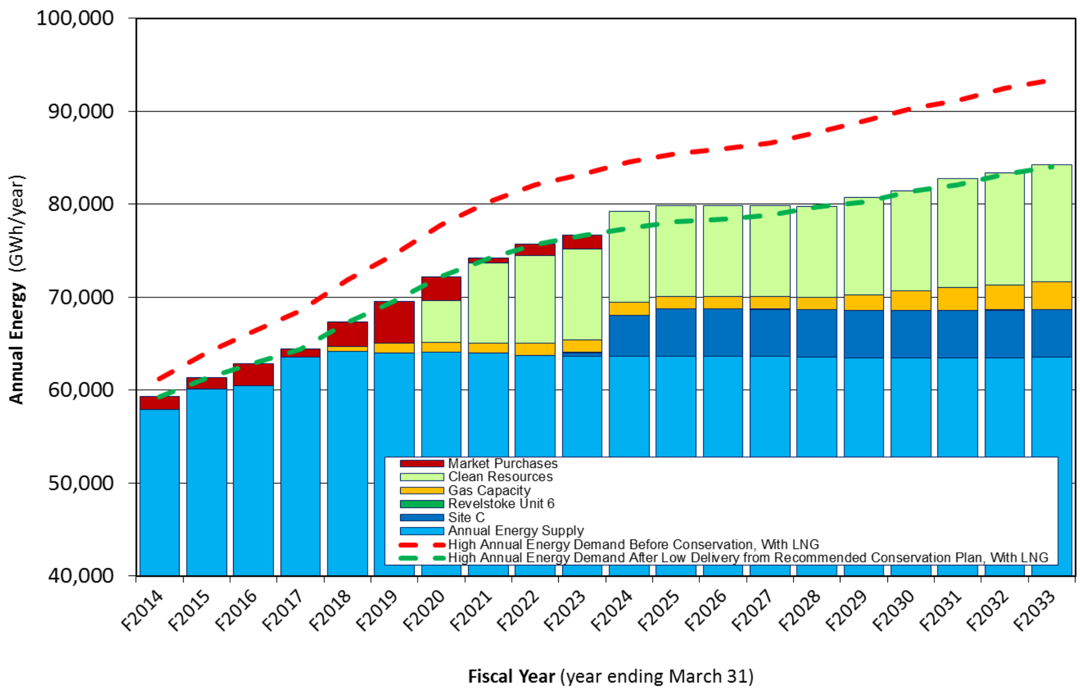
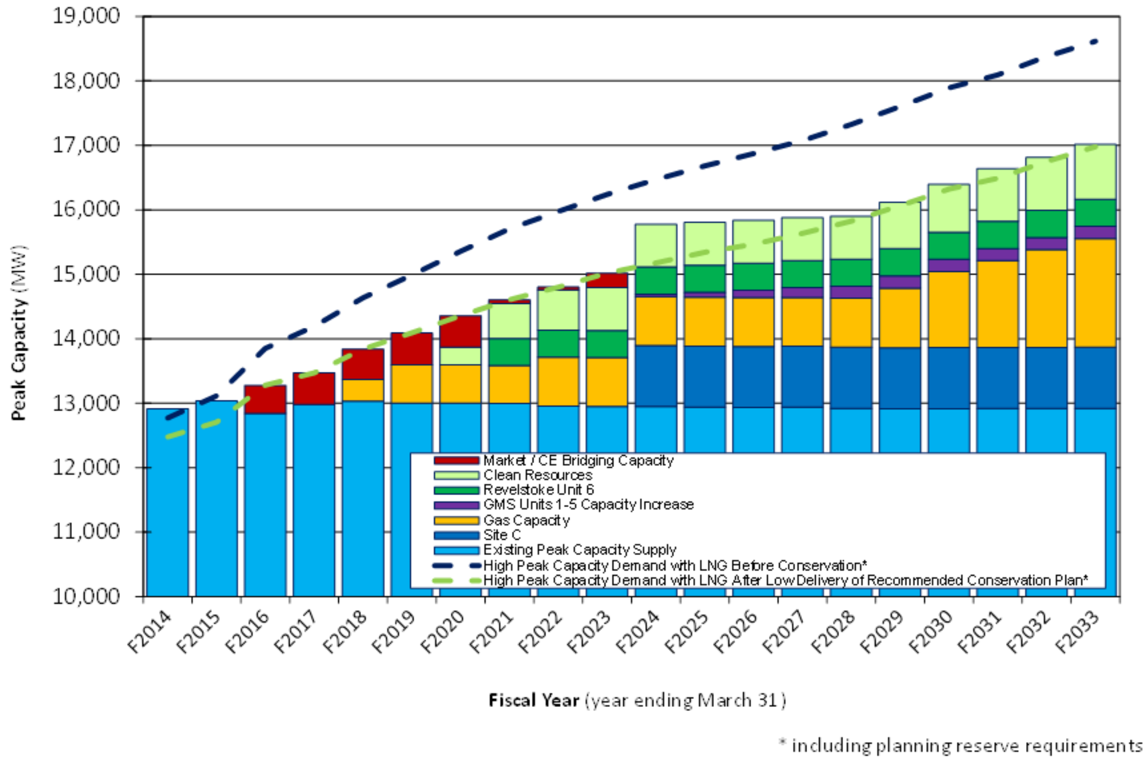


Figure 8-10 Capacity Load/Resource Balance: CRP 2



What can be seen from CRP2 is that generally more natural gas-fired generation is required. The rationale for CRP2, with Expected LNG, is to highlight and drive the incremental transmission resources that would be required in that situation.

BC Hydro contemplated having a scenario with both high LNG and non-LNG load, however, the analysis done in Chapter 6 on the North Coast region suggested that it would be unlikely at this time to move towards a second 500 kV transmission line. Rather, it is anticipated that additional LNG would be supported by gas fired generation on the North Coast.

8.4.7 Recommended Action 17: Fort Nelson area supply options

Investigate procurement options to serve future Fort Nelson load.

Recommended Action 13 addresses electrification of the larger Horn River Basin, which would include the Fort Nelson region. In the absence of clarity on HRB electrification, BC Hydro must continue to be prepared to supply loads in the Fort Nelson region as described in Chapter 2.

BC Hydro recommends that it continue to address the Fort Nelson area requirements in the following fashion:

- BC Hydro will maintain N-1 level of service to the Fort Nelson area over the long term. With that in mind, and in light of load forecast uncertainties, BC Hydro will avoid new supply commitments until load growth signals become more certain.
- As a bridging strategy, and to the extent that relatively sizeable industrial loads materialize earlier than expected, BC Hydro will provide interruptible (N-0) service to such loads on a temporary basis until such time as N-1 service becomes available. BC Hydro would be able to serve up to 112 MW of load with combined Fort Nelson Generating Station (**FNG**) and Alberta supply on an interruptible (N-0) basis.
- BC Hydro will continue to monitor Fort Nelson area load growth including sign posts for load developments and on-the-ground market intelligence
- BC Hydro will continue to investigate and engage in actions concerning the range of potential supply options, including implementation in collaboration with Alberta of a Fort Nelson Load Shedding Remedial Action Scheme (**LSRAS**) and assessment of local gas-fired generation options to meet the range of forecast capacity shortfall.

8.4.7.1 Justification

In the mid load scenario, the load is expected to grow from its current level of about 30 MW (as measured by winter peak capacity) to about 43 MW by F2020 reaching the N-1 threshold for planning purposes by about F2018 or F2019.

While BC Hydro expects load growth to be modest over the next five years (F2014 to F2018), there are significant uncertainties to the forecast due to potential impacts from Horn River Basin development and/or other unexpected load developments such as a restart of currently shut-down forestry mills. These uncertainties could defer the expected capacity shortfall to beyond F2018, or cause the shortfall to occur earlier than F2018.

Given the substantial near-term load forecast uncertainties, BC Hydro is not willing to make a significant investment commitment at this point. BC Hydro is taking actions to address these uncertainties and set the stage for longer-term planning actions as well, without losing sight of natural gas industry and Horn River Basin developments. These actions will include the close monitoring of Fort Nelson area load in order to reflect these changes into its load forecast and its servicing plans.

8.4.7.2 Execution

Key activities include:

- In collaboration with the Alberta Electric System Operator (**AESO**) and ATCO Power, complete in F2014 design and implementation of Fort Nelson LSRAS that will allow BC Hydro to serve increased load on an interruptible basis until additional supply is added. Estimated Cost: $2 million.
- BC Hydro has identified and will refine assessment of options to meet the range of forecast capacity shortfall, including the option of expanding the existing FNG by adding a second unit. Resource requirements will be primarily for staff time and potential for external consulting support in the range of $50,000 to $100,000.

8.4.7.3 Future Approval Process

No material regulatory approval processes are envisioned at this time given the scope of the Recommended Action.

8.4.8 Transmission Contingency Plans

The TCPs are intended to address the key transmission shortages that impact BC Hydro's resource plans. As demonstrated in section 6.8.6, there do not appear to be any bulk transmission regions that would cause BC Hydro supply concerns over the next 10 years.

8.5 Additional IRP Recommendations

8.5.1 Province-Wide Electrification/GHG Reduction Initiatives

Section 6.7 addresses the potential implications of the *CEA* GHG-related objectives that could drive general electrification across the economy, in end-uses such as space and water heating, passenger and freight vehicles, and industrial equipment (e.g., large compressors).

The potential costs and impacts of general electrification would be significant. BC Hydro will undertake preparatory actions with low costs:

- Continue to provide analysis and support to government to identify where electrification would be expected to occur in response to strong climate policy
- Continue distribution system studies and related activities, in conjunction with smart meters and smart grid implementation, to ensure that BC Hydro's transmission and distribution infrastructure is able to supply the increased loads (e.g., electric vehicles, heat pumps, distributed generation, load curtailment) that could result from significant electrification.

BC Hydro's ongoing efforts to monitor provincial, national and international climate policy developments and analyze potential system demand will facilitate responding to potential future policy-driven electrification initiatives.

8.5.2 Export Market Analysis

Section 5.8 of this IRP provides an analysis of potential export market opportunities. The key conclusion is that market conditions do not justify the development of new, additional clean or renewable resources for the export market. Since the conditions underpinning these market dynamics are expected to persist for the foreseeable future, BC Hydro anticipates no incremental expenditures for export but will continue to monitor the export markets for future opportunities.

8.5.3 Transmission Planning for Generation Clusters

In section 6.9, the IRP evaluated the nine regions in B.C. that had the highest resource clean or renewable generation density (generation clusters) that may benefit from the pre-building of new bulk transmission to result in a more cost-effective transmission system development with a reduced environmental footprint. The analysis pointed to the potential to somewhat reduce environmental footprints as a result of optimal transmission configurations. However, there is only a marginal financial benefit associated with developing clusters to meet customer demand. In addition, there is a significant uncertainty over which resource options will ultimately be developed. As such, BC Hydro will consider transmission advancement for generation clusters during acquisition processes when projects in these cluster regions are being bid.

8.5.4 IRP Submission Cycle and Amendments

Subsection 3(6)(b) of the *CEA* provides that subsequent IRPs must be submitted every five years after submission of this first IRP unless a submission date is prescribed by LGIC regulation. The submission date for the next IRP is August 2018 in the absence of such a regulation.

Subsection 3(7) of the *CEA* enables BC Hydro to submit an amendment to an approved IRP. A decision to submit an amendment prior to the next IRP will depend on a number of factors, including but not limited to LNG final investment decisions, changes to B.C. Government policy, significant load forecast changes, or other issues that may require First Nations consultation and stakeholder input.