Chapter 6

Resource Planning Analysis
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6.1 Introduction

This Chapter presents the results and conclusions drawn from the Integrated Resource Plan (IRP) resource planning analysis, which was conducted according to the analytical framework described in Chapter 5. The results from the IRP analysis inform BC Hydro’s plan for resources under the following conditions:

- **Mid-Gap Conditions**: As described in Chapter 2, the mid-gap (i.e., mostly likely) is based on BC Hydro’s mid Load Forecast, which includes the large proposed load from the Initial LNG facilities. The Recommended Actions to fill the mid-gap lead to the Base Resource Plan (BRP) as described in section 9.3.1 of Chapter 9.

- **Contingency Conditions**: Contingencies include significant planning uncertainties such as load growth being greater than expected (i.e., large gap) or planned resources under-delivering or being delayed. Proposed actions to prepare for contingency conditions are presented in section 9.3.2 of Chapter 9.

- **Incremental Load Scenarios**: Potential high growth scenarios include additional liquefied natural gas (LNG) load growth in the North Coast. Proposed actions to meet these large and mostly binary incremental loads, should they emerge, are presented in section 9.4.4 of Chapter 9.

As discussed in Chapter 2, the load from Initial LNG has a significant impact on the load-resource balance:

- The energy load-resource balance without the Initial LNG load indicates that BC Hydro will have sufficient surplus energy resources to meet normal load growth until F2022 (approximately the time that Site C would be available). With the addition of the Initial LNG load, a load-resource gap would be advanced to F2017 with a gap of about 700 GWh/year by F2017 growing to about 4,900 GWh/year by F2021.
• The capacity load-resource balance shows that BC Hydro has a capacity gap (about 250 MW) beginning in F2017 without the Initial LNG load; with the Initial LNG load, the capacity gap increases to approximately 950 MW.

Given that the load represented by Initial LNG is large and has timing uncertainty, any conclusions that are dependent on it reaching critical milestones are identified in each major section of this chapter.

6.1.1 Chapter Structure
The results of the IRP analysis described in this Chapter are organized by major topic/question set out below, which correspond to the discussion in Chapter 5. In the IRP analysis, BC Hydro begins by considering:

• Natural Gas-Fired Generation (section 6.2): Natural gas is cost-effective capacity resource option, but is limited by the Provincial 93 per cent clean energy objective. This section explores how natural gas can be used to meet resource planning needs in a manner consistent with the 93 per cent clean energy objective. Setting out the role of gas at the beginning of this chapter allows the rest of the IRP analysis to focus on clean resource alternatives.

• Demand-Side Measures (DSM) (section 6.3): DSM is a low cost resource option with a low environmental footprint. Because DSM has these attributes, BC Hydro first determines the extent to which the load resource gap should be reduced with cost-effective DSM.

• Site C Clean Energy Project (Site C) (section 6.4): BC Hydro’s 2008 Long-Term Acquisition Plan (LTAP) identified Site C as a cost-effective resource, which was further reinforced by the findings of the 2010 ROR. Site C is undergoing an environmental review process. Because of its expected cost-effectiveness and its significant energy and capacity potential, the continued role of Site C is explored next.

• Incremental New Loads: Large new loads could emerge in the North Coast (section 6.5), Fort Nelson/Horn River Basin (section 6.6) and from general
electrification (section 6.7): These sections describe scenarios which could have significant implications on resource requirements, but the timing of the load commitments needs to be confirmed.

- Independent Power Producer (IPP) Acquisition (section 6.8), Transmission (section 6.9), Capacity and Contingency Analysis (section 6.10): These sections provide the resource requirements to fill the remaining load-resource gap and develop strategies to manage the range of planning uncertainties (including the incremental load scenarios) that are analyzed.

The following sections present a high level summary of the analytical results, including key findings from the financial, environmental and economic development attributes. Detailed results from the IRP analysis: portfolios, environmental and economic development attributes results are included in Appendix 6A and 6B respectively, grouped again by the same IRP topics/questions.

6.2 Natural Gas-Fired Generation

6.2.1 Introduction

The use of gas-fired generation in B.C. is limited by the following energy objectives as set out by the CEA:

- To generate at least 93 per cent of the electricity in British Columbia from clean or renewable resources;
- To reduce B.C. greenhouse gas (GHG) emissions;
- To encourage energy efficiency and clean or renewable electricity through:
  - Development of innovative technology in B.C.;
  - Use of waste heat, biomass or biogas; and
  - Use and development of clean or renewable resources in First Nations and rural development.
As discussed in section 4.3.2.2, there is a requirement for new natural gas-fired generation to have net zero GHG emissions pursuant to Policy Action No. 18 of the 2007 Energy Plan.

Natural gas-fired generation is also subject to the Carbon Tax; however, the Provincial Government has indicated in the Climate Action Plan that it is not inclined to charge the Carbon Tax when gas-fired generation were required to acquire and retire offsets. The generation would be exempted from the Carbon Tax under section 84 of the Carbon Tax Act, which provides that the Lieutenant Governor in Council may make regulations providing for exemptions from the payment of tax, or for refunds of all or part of the tax paid, with respect to a fuel or combustible that is the source for GHG emissions that are subject to the requirements of the Environmental Management Act (EMA). Such a regulation has not been issued to date by the Lieutenant Governor in Council.

In order to meet the objectives of the CEA, BC Hydro needs to limit and optimize the use of gas-fired generation so its generation is at least 93 per cent clean. In the IRP analysis, BC Hydro evaluated gas-fired generation within the remaining headroom of 7 per cent for non-clean resources and has only contemplated exceeding this headroom in scenarios which will be noted, where there are limited supply options.

Gas-fired generation can be a significant source of dependable capacity and firm energy. The dispatchable and dependable nature of gas-fired generation can complement intermittent and non-dispatchable renewable resources such as wind.

---

1 The Climate Action Plan states at page 15: “To avoid unfairness and what might effectively be double taxation, the carbon tax and complimentary measures such as the ‘cap and trade’ system will be integrated as these other measures are designed and implemented”.

2 Although all non-clean resource options can use the 7 per cent non-clean headroom, the discussion here only focuses on gas-fired resource options. Gas is the default non-clean generation option for most utilities because it is a proven technologically, is available in significant amounts, is the most efficient, and has the least GHG emissions and criteria air contaminants compared to other non-clean options. Other non-clean options such as diesel will continue to be generation options where no other options are available/feasible (e.g., in some non-integrated areas) but their usage/energy volume will be negligible.
and run-of-river hydro\(^3\) enabling their integration into the system. The cost of
gas-fired generation is competitive given the current price of natural gas and the
longer term outlook for gas prices and GHG offset costs in most of the market
scenarios analysed in the IRP. Unlike many other resource options, gas has siting
flexibility allowing it to be sited in locations that yield greater value (e.g., near load
centres or in transmission constrained areas). Its relatively short construction lead
time (once permitting is secured) also makes it a good candidate to be a
contingency resource.

However, gas-fired generation has notable drawbacks. The cost of natural gas has
historically been volatile while liquid markets for GHG offsets are still emerging
creating uncertainty around the cost of gas-fired generation. Furthermore, there are
permitting and regulatory risks of developing gas-fired generation in B.C.

While being mindful of benefits and drawbacks of gas-fired generation, the key IRP
questions on this resource option are:

- What is the optimal use for this resource within the 7 per cent non-clean
  headroom?
  - Where should gas-fired generation be sited?
  - When should the 7 per cent non-clean headroom be used, now or later,
    considering future uncertainties?

### 6.2.2 Applying the 93 per cent Clean Energy Objective to Resource Planning

The 93 per cent clean objective, as stated in the CEA, is a provincial objective.
BC Hydro has modelled, planned and operated its system with a view that it will
need to meet the objective within its system. The objective applies to the actual

---

\(^3\) For example, gas-fired generation can be turned off when generation from non-dispatchable run-of-river
hydro is high when load is light such as during the freshet. Gas turbines can also provide firming for wind
integration.
output of generation facilities as opposed to the planned reliance on the facilities\(^4\), and BC Hydro must plan its system such that the objective can be met when operating its facilities.

As part of this IRP, BC Hydro reviewed several possible interpretations of the 93 per cent clean objective, their applications to the IRP and their consistency with the CEA as described as follows:

(a) Meet the objective on average:

- For the IRP, this would require developing a plan that would allow BC Hydro’s generation to be at least 93 per cent clean while meeting all of BC Hydro’s load obligations net of DSM from B.C. resources and be able to do so under average water conditions (i.e., being able to meet the objective by averaging the clean generation percentage over a period of time, but not being able to meet the 93 per cent objective in every year). In this approach, BC Hydro would develop resource plans where energy contribution under average water conditions of Heritage hydro facilities combined with the firm energy contribution from clean IPP resources would be at least 93 per cent of load requirements; or

(b) Meet the objective every year:

- For the IRP, this would require developing a plan taking similar approach as interpretation (a) but for critical water conditions.

(c) Meet the objective (on average or every year) by relying on import of market energy:

- For the IRP, this would require developing a plan that would allow BC Hydro’s generation to be at least 93 per cent clean without consideration of whether all of BC Hydro’s load obligations can be met from B.C. resources while maintaining the objective. In practice, this would allow BC Hydro to rely on significant amount of gas-fired generation in BC Hydro’s resource plans with the

\(^4\) Specifically, it is the ratio between clean electricity and the total electricity generated within the Province.
intention to displace gas-fired generation with market energy import to meet load during operation. The minimized generation from gas-fired facilities in B.C. to meet load allows BC Hydro’s generation to be at least 93 per cent clean even though a significant portion of the BC Hydro system load would be met by market imports.

BC Hydro has ruled out approach (c) since this would defeat the intent of the CEA in setting out the electricity self-sufficiency requirement and the 93 per cent clean objective.

In the past, as discussed in the 2008 Long-Term Acquisition Plan (LTAP), BC Hydro has been planning according to approach (b) based on the 90 per cent clean generation policy objective in the 2007 Energy Plan. By comparison, approach (a) would provide greater flexibility to use gas-fired generation. BC Hydro proposes approach (a) in this IRP going forward because it is consistent with the recent move to average water planning and focus on cost effective actions that meet the intent of the energy objectives. In planning energy to average water conditions, BC Hydro is able to manage its resources and avoid being oversupplied in a low priced market. Similarly, with approach (a), it will be able to meet the 93 per cent clean objective and manage the emission of GHGs at the desired level over a period of time, but still leave enough flexibility to add gas-fired generation in order to maintain system reliability or where significant economic benefits can be achieved.

6.2.3 Resource Planning with Gas-Fired Generation

If BC Hydro plans on gas-fired generation, it would plan to rely upon these facilities to generate at least 18 per cent of the time during the course of a year (i.e., capacity factor) and the associated energy will be the firm energy contribution to the resource plan. The 18 per cent capacity factor assumption was established in the 2008 LTAP to reflect that gas-fired units, even if built purely for capacity purposes, would need to be capable of running at least at 18 per cent capacity factor to provide dependable capacity.
The decision of whether to have more than the planned 18 per cent energy contribution from the gas-fired facilities would depend upon the expected utilization of a particular plant within the available 7 per cent non-clean headroom. Of the two main categories for gas-fired turbines:

- Simple Cycle Gas Turbines (SCGT) have lower capital cost, have faster ramp rates and allow frequent starts/stops, but are less efficient. Therefore, SCGTs are typically built for their dependable capacity (for use as peakers\(^5\)). In modelling SCGTs in IRP portfolio analysis, a firm energy contribution and minimum generation based on 18 per cent capacity factor have been assumed;

- Combined Cycle Gas Turbines (CCGT) are more efficient than SCGTs, have higher capital costs, and are typically built where there is a need for both dependable capacity and an expectation of relatively high utilization (typically used for base load energy). In modelling CCGTs in IRP portfolio analysis, a firm energy contribution of 90 per cent and minimum generation of 70 per cent capacity factor have been assumed.

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

As mentioned in section 6.2.2, in adopting approach (a), BC Hydro would plan such that its average water output of heritage facilities combined with the firm capability of clean IPP resources would be at least 93 per cent of the load net of DSM. BC Hydro has four existing gas-fired generation facilities in its system\(^6\) that take up part of the headroom available. They are:

- Fort Nelson Generating Station;
- Island Cogeneration Plant;
- Prince Rupert Generating Station; and

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\(^5\) Peakers (or peaking plants) are power generation plants that typically only run at times of peak demand.

\(^6\) As described in section 2.3.2.1 and consistent with the CEA directives, BC Hydro does not plan on any energy contribution from Burrard and hence Burrard does not have any impact on the 93 per cent objective from a planning perspective. BC Hydro also operates several diesel generators in non-integrated areas. Their energy contribution is relatively minor and has no material impact on the 93 per cent clean objective.
- McMahon Cogeneration Plant.

These existing facilities provide approximately 3,500 GWh/year of non-clean firm energy contribution. BC Hydro plans to continue to rely on the energy from these facilities within the planning horizon. Figure 6-1 shows the remaining non-clean energy headroom available for any new gas-fired generation for the planning horizon based on the mid-gap scenario. Figure 6-2 shows the corresponding installed capacity headroom for new gas-fired units assuming an 18 per cent capacity factor.

**Figure 6-1** Remaining Non-Clean Headroom (Firm Energy)
6.2.5 Permitting for Gas-Fired Generation

Gas-fired generation greater than or equal to 50 MW requires an Environmental Assessment Certificate (EAC) pursuant to the B.C. Environmental Assessment Act and an air emission permit under the EMA. In many regions of the Province, securing an EAC and/or air emission permit may be a lengthy process with an uncertain outcome. There may be limits to how much gas-fired generation is permitted. For example, it is uncertain whether the number of units potentially required to meet loads from LNG facilities in the North Coast can all be sited near the loads. However, for the purpose of IRP portfolio analysis, a limit has not been assumed or modelled.

It would also be difficult for a proponent to obtain an EAC and/or air emission permit for gas generation in the Lower Mainland. Metro Vancouver has responsibility for issuing air emission permits for Lower Mainland facilities, and has taken the public position that it would not welcome gas generation within the Lower Fraser Valley.

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7 Per section 31 of EMA, S.B.C. 2003, c53.
airshed\textsuperscript{8}. In addition, the Province, in its news release\textsuperscript{9} concerning Direction No. 2\textsuperscript{10} to the British Columbia Utilities Commission (BCUC) providing that for planning purposes Burrard Thermal Generating Station (Burrard) cannot be relied on for any firm energy, cited concerns with Burrard air emissions in the Lower Fraser Valley airshed.

6.2.6 Cost of Gas-Fired Generation Compared to Clean Resources

The unit energy cost (UEC) for gas-fired generation under the range of market scenarios considered in this IRP are shown in Table 6-1. The UECs shown are adjusted for delivery to the Lower Mainland to make them comparable to the $129/MWh (2011$) adjusted levelized firm energy price from the Clean Power Call. Gas-fired generation is generally lower in cost compared to the Clean Power Call, especially under the most likely market scenario (i.e., Market Scenario C). The table also illustrates that the comparative energy benefit is maximized when the energy is generated using more efficient machines operating at a higher capacity factor. The larger 250 MW CCGTs are more efficient than either the 50 MW CCGTs or the 100 MW SCGTs and hence have the lowest energy cost. Efficient generation of energy also reduces amount of GHGs that are created per GWh.


Gas-fired generation is also a low cost source of capacity. While detailed discussion of capacity options is provided in Chapter 3 and later in section 6.10, the unit cost of capacity (UCC) of a SCGT at the point of interconnection compared against supply side capacity options is provided here in Table 6-2 for quick reference.

<table>
<thead>
<tr>
<th>Market Scenarios</th>
<th>Likelihood (%)</th>
<th>UEC of a 100 MW SCGT ($/MWh)</th>
<th>UEC of a 50 MW CCGT ($/MWh)</th>
<th>UEC of a 250 MW CCGT ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario A (High gas, Mid GHG)</td>
<td>5</td>
<td>175</td>
<td>159</td>
<td>131</td>
</tr>
<tr>
<td>Scenario B (Mid gas, Mid GHG)</td>
<td>30</td>
<td>126</td>
<td>119</td>
<td>93</td>
</tr>
<tr>
<td>Scenario C (Low gas, Carbon tax)</td>
<td>40</td>
<td>94</td>
<td>93</td>
<td>67</td>
</tr>
<tr>
<td>Scenario D (Mid gas, High GHG)</td>
<td>5</td>
<td>151</td>
<td>139</td>
<td>111</td>
</tr>
<tr>
<td>Scenario E (Low gas, Carbon tax)</td>
<td>20</td>
<td>94</td>
<td>93</td>
<td>67</td>
</tr>
</tbody>
</table>

BC Hydro also carried out analysis to compare portfolios with gas-fired generation to portfolios with all clean energy resources. Two portfolios with gas-fired generation were examined: one with SCGTs and one with CCGTs (250 MW). Both portfolios with gas-fired generation were consistent with the 93 per cent clean energy objective. The modelling assumptions of this analysis are shown in Figure 6-3. For this comparison, all gas-fired units were assumed to be in the Kelly Lake region because of its proximity to the Lower Mainland load centre and a major gas pipeline. The results of the portfolio analysis (see Table 6-3) show that:

- The PV costs of the three portfolios are the same under Market Scenario A. Here, gas-fired generation is not selected as natural gas prices are high; i.e., the resource composition of the three portfolios is effectively the same.
• In all other Market Scenarios, there are PV cost savings with adding small amounts of gas-fired generation in a manner consistent with the 93 per cent clean energy objective.

• The use of gas-fired generation within the 7 per cent headroom can result in cost savings as high as $370 million.

**Figure 6-3  Modelling Map – Natural Gas-Fired Generation**

MODELLING MAP – NATURAL GAS-FIRED GENERATION

**Uncertainties/Scenarios**

<table>
<thead>
<tr>
<th>Gap Size</th>
<th>Large</th>
<th>Midload, low DSM</th>
<th>Mid</th>
<th>Mid load, high DSM</th>
<th>Small</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Market Scenario</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Coast Load</td>
<td>Initial LNG Only</td>
<td>Initial LNG &amp; LNG3</td>
<td>Initial LNG, LNG3 &amp; Future Mining</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**IRP Resource Choices**

<table>
<thead>
<tr>
<th>DSM Option</th>
<th>DSM 1</th>
<th>DSM 2</th>
<th>DSM 3</th>
<th>DSM 4</th>
<th>DSM 5</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Site C</th>
<th>Site C in at EISD</th>
<th>Site C is an option</th>
<th>Site C is NOT an option</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Thermal Generation</th>
<th>No additional thermal</th>
<th>Gas (SCGT) w 93% clean objective</th>
<th>Gas (CCGT) w 93% clean objective</th>
</tr>
</thead>
</table>

**Modelling Assumptions & Parameters**

<table>
<thead>
<tr>
<th>Wind Integration Cost ($/MWh)</th>
<th>$5</th>
<th>$10</th>
<th>$15</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Modelling Horizon (yrs)</th>
<th>20</th>
<th>30</th>
</tr>
</thead>
</table>
### 6.2.6.1 Environmental and Economic Development Considerations

The use of gas-fired resources to displace clean energy, transmission, or clean capacity resources will have an effect on the environmental measures being tracked for this IRP. As well, since the capital and operating cost of gas plants are different than alternative resources, economic development attributes will differ as well across these resource choices.

The comparisons of environmental and economic development attributes will be reported out where natural gas is tested as an alternative to supplying clean resources via an upgraded transmission line for the North Coast region (section 6.5).

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

As described in the previous section, the IRP analysis has demonstrated that gas-fired generation has a cost advantage over clean resources in most market scenarios. However, given the limited amount of gas-fired generation that is available under the 93 per cent clean objective, BC Hydro has sought to identify the optimal use of gas-fired generation that maximizes the benefits to the ratepayers.

Judicious application of gas-fired generation can potentially provide significant economic benefits over and above the ones identified in the previous section that were driven primarily by the cost of energy from gas-fired generation being lower cost than alternatives.
As identified in section 2.4, BC Hydro has significant capacity need. Using gas primarily for capacity has added value to BC Hydro because of the lack of reliable alternatives (available alternatives are developmentally and/or operationally uncertain) and because of its premium quality being dispatchable and dependable.

Almost all of the low-cost hydro-electric capacity units that were available to BC Hydro have now been developed to meet load growth. Revelstoke Unit 5 is now in service while Mica Units 5 and 6 are currently under construction. Revelstoke Unit 6 and Site C are the only remaining large scale hydro units available to BC Hydro, and these would be required at their earliest in-service dates to meet BC Hydro’s mid Load Forecast.

Pumped storage hydro units have been identified and modelled in the analysis shown in section 6.2.6 as a source of clean capacity and studies have shown a sizeable resource potential with an estimated lead time of eight years. However, pumped storage units have never been permitted and developed in B.C. and significant uncertainties around the permitting process and development timelines exist. Pumped storage hydro is also more expensive than gas-fired SCGTs as shown in Table 6-2. DSM capacity options are other potential alternatives for capacity but they are limited in potential and have developmental/operational uncertainties. As a result, gas capacity is the default source of capacity should no other clean options be available. A comparison of Figure 6-2 and Figure 6-4 shows that the use of gas-fired units primarily for capacity instead of for energy allows BC Hydro to maximize the amount of capacity it can rely on from gas given the limited non-clean headroom (an increase from 170 MW to over 800 MW by F2021, more than quadruple). Further discussion on gas option and capacity alternatives are in section 6.10.
The remaining questions are “where” and “when” should gas capacity be used to yield further benefits.

6.2.7.1 Using Gas as a Transmission Alternative

Siting gas-fired generation strategically to avoid or delay transmission can provide added value over using it generally in the system.

Siting gas-fired generation in remote areas (e.g., areas currently connected to the system with only a long radial transmission line or areas currently non-integrated) could avoid or defer costly transmission and/or enable BC Hydro to serve load that it may otherwise not able to serve because of long transmission lead time. However, in evaluating these benefits, BC Hydro must also consider other counter balancing costs/factors associated with avoiding transmission. For example, when gas is used as a transmission alternative, local capacity needs may require several smaller sized units with additional units for redundancy to provide the same level of reliability as provided by the avoided transmission line. As shown in Table 6-1, smaller units are generally more costly and less efficient and could erode or eliminate the locational benefits.
In this IRP, BC Hydro has identified a few locations where siting gas could yield additional benefits compared to siting in the Kelly Lake region to meet system load in general. Table 6-4 provides a list of these locations, the potential transmission options to these regions and their costs for comparison. The following subsections describe each of these regions and their planning issues in more detail.

<table>
<thead>
<tr>
<th>Region</th>
<th>Potential Transmission Requirement</th>
<th>$ Billion*</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Coast</td>
<td>500 kV from Williston to Skeena</td>
<td>1.0</td>
</tr>
<tr>
<td>Fort Nelson/Horn River Basin</td>
<td>500 kV North East Transmission Line</td>
<td>1.0</td>
</tr>
<tr>
<td>Lower Mainland/ Vancouver Island</td>
<td>Future 500 kV Interior to Lower Mainland Transmission line (5L46)</td>
<td>0.6</td>
</tr>
<tr>
<td>Peace Region</td>
<td>Dawson Creek Area Transmission and Groundbirch Dawson Area Transmission (230 kV)</td>
<td>0.25</td>
</tr>
</tbody>
</table>

* Direct capital cost in 2011 $ with -50 per cent to +100 per cent accuracy

**North Coast**

As discussed in section 2.5 and further discussed in section 6.5, the electricity demand in the North Coast region may increase significantly, primarily due to the potential development of several LNG facilities near Kitimat. The region is currently interconnected to the rest of the BC Hydro system by a radial 500 kV transmission line (consisting of three cascading 500 kV lines) that would not be capable of transferring sufficient electricity to serve all of the potential new loads. This radial line would be close to capacity in meeting the mid load forecast with initial LNG even after upgrading using series compensation. A new 500 kV transmission line requires several years of development time and would have high capital costs and permitting risks. In comparison to building a new transmission line and adding more generating capacity units at other locations on the integrated system, gas-fired SCGT generation in the North Coast may be the most practical option to meet the increased regional loads in a timely manner. BC Hydro analyzed the benefit of installing SCGT units in the North Coast compared to the alternative of constructing a new 500 kV transmission line and locating a comparable amount of gas-fired
energy in the Kelly Region, with the gas units operating in compliance with the
93 per cent clean objective in both cases. The result of this analysis is presented in
section 6.5.

Fort Nelson/Horn River Basin

As described in section 2.5, the Fort Nelson region is a non-integrated area currently
served by gas-fired generation and the nearby Horn River Basin is a region with
significant natural gas production potential. Gas-fired generation offers a potentially
cost-effective alternative to B.C.-based transmission or Alberta-based transmission
alternatives, but can contribute to GHG emission production and may use part or all
of the 7 per cent non-clean headroom. However, the relative cost-effectiveness of
various supply strategies and available gas head room are dependent on market
scenario and the load scenarios for the Fort Nelson/Horn River Basin region. The
results of BC Hydro’s analysis are summarized in section 6.6.

Lower Mainland / Vancouver Island

The Lower Mainland/Vancouver Island region accounts for approximately
70 per cent of BC Hydro system load. Only around 25\textsuperscript{11} per cent of the peak Lower
Mainland/Vancouver Island load can be met by resources within the region, meaning
most of its capacity requirement is met via transmission. Sources of capacity in the
Lower Mainland/Vancouver Island other than gas, such as pumped storage facilities,
have significant uncertainties in terms of development and operations. As discussed
in section 6.9, if pumped storage facilities in the Lower Mainland/Vancouver Island
are not available, an additional line from the Interior to Lower Mainland after 5L83
may be required by F2030 or as early as F2024 under large gap condition. This next
line can be avoided or delayed by siting gas in Lower Mainland/Vancouver Island
region. However, siting gas-fired generation in the Lower Mainland would be more
challenging from a permitting perspective as discussed in section 6.2.5.

\textsuperscript{11} Excluding Burrard capacity.
Peace Region

Section 2.5 identified substantial growth potential in the Dawson Creek and Groundbirch areas as the gas industry develops unconventional gas reserves in the Montney gas basin. The high load expectation has triggered the need for transmission upgrades and additions in the Dawson Creek area. The use of gas-fired generation is an alternative to the transmission upgrades; however, the use of gas-fired generation in this case involves a trade-off where the excess costs associated with use of smaller less efficient units and the need for additional redundant units may outweigh the benefits of avoiding the costs of additional transmission. BC Hydro’s application to the BCUC for a Certificate of Public Convenience and Necessity for the Dawson Creek/Chetwynd Area Transmission Project provides additional detail. The Dawson Creek area would require the installation of relatively small units (e.g., 50 MW to 75 MW) in order to have redundancy such that an acceptable level of reliability can be achieved. Such redundancy is required to allow for both planned outages (maintenance) and unplanned outages (breakdowns) of generating units. The use of small gas-fired units, even if configured as CCGTs will lead to cost inefficiencies relative to larger unit sizes because of higher unit capital costs (e.g., typically $3,000/kW for 50 MW CCGT as compared to $1,450/kW for 250 MW CCGT), and higher operating costs associated with the additional maintenance required for multiple unit configurations. There will also be operational inefficiencies for the smaller CCGT units since they have generally lower thermal efficiencies (higher heat rates) compared to the larger units. There may be further inefficiencies (e.g., operation at partial unit loadings and uneconomic dispatch) associated with the need for "reliability must run" operation of the local units in order to ensure an acceptable level of reliability is maintained.

6.2.7.2 Using Gas as a Contingency Resource for Generation and Transmission

Given the permitting and development timeline uncertainty of other capacity options, gas is the most certain and may be the only capacity contingency resource option available for significant dependable capacity in the near term. Section 6.10
Chapter 6 - Resource Planning Analysis

contemplates whether gas-fired generation should be used to address near-term
capacity shortfalls (now) or be reserved for contingency applications (later), and
concludes that contingency applications provide added value because of the option
value to react to future uncertainties. However, given potential lengthy permitting
requirement, exploring gas options in advance of need would be required to ensure
its viability as contingency option. The use of gas as contingency resource is further
discussed in section 6.10.

6.2.8 Conclusions

Based upon the objectives in the CEA, BC Hydro will plan to meet the 93 per cent
clean energy objective and limit the amount of gas-fired generation that will be
developed ensuring that the objective can be met under average water conditions.

Gas-fired generation has a cost advantage over other resources given current gas
and GHG prices as well as under most Market Scenarios considered in this IRP.
However, to optimize the benefit of the 7 per cent non-clean headroom, BC Hydro
should reserve gas-fired generation primarily for capacity (given a lack of reliable
capacity alternatives) while potentially siting it as a transmission alternative (to
benefit from transmission deferral/avoidance). This has the added benefit of being
able to use gas-fired generation as a contingency resource for generation and
transmission (to maintain flexibility given gas may be the only viable option in the
near term).

BC Hydro has identified a few regions where siting gas may yield significant
transmission deferral benefits. However, the load in these regions and thus the need
for transmission has not been confirmed. Therefore, BC Hydro should not commit to
using gas in a specific region at this time but should maintain the option to do so.
The regions for gas-siting considerations should include North Coast, Fort Nelson,
Vancouver Island and Kelly Lake. The Lower Mainland is not considered because
permitting is expected to be very difficult.
Given potential lengthy permitting requirement, BC Hydro should explore the gas option in advance of need to shorten lead time in order to ensure gas’ viability as contingency option.

The conclusions on this gas-fired generation section support Recommended Action No. 13 in the “Prepare for Potentially Greater Demand” category as described in Chapter 9. These conclusions are not contingent on Initial LNG because BC Hydro continues to have a lack of reliable capacity alternatives and face potential regional transmission needs and contingency situations given the planning uncertainties described in section 6.10.

### 6.3 Demand-Side Measures

#### 6.3.1 Introduction

The main question regarding DSM for this IRP is:

- What is the cost-effective level of DSM to rely on?

As outlined in Chapter 1, BC Hydro generally uses the BCUC’s definition of cost-effectiveness which includes both cost and considerations of schedule/delivery risk, reliability, timing, location and environmental impacts. To help understand the impacts of the different levels of DSM, this section examines the following:

- Near-term DSM Strategy: The IRP analysis first examines whether the near-term DSM activities should be adjusted to respond to a temporary energy surplus.
- Long-term DSM Strategy: The long-term analysis involves analyzing the five DSM options developed, including both the quantified uncertainty of their forecast savings as well as the uncertainties and risks not quantified in the DSM uncertainty assessment. Each of the following factors are addressed, in turn, and then pulled together for an overview to determine the cost-effective level of DSM.
  - Impact of DSM options on the load-resource balance;
6.3.2 Near-Term DSM Strategy

As discussed in section 2.4, the load-resource balance indicates a period of surplus energy up to F2017. Thereafter, it may show a surplus or deficit of energy depending on Initial LNG loads, which are subject to size and timing uncertainty. Given that this near-term surplus will be accentuated by the current trajectory of DSM activities, two strategies to address this surplus were examined:

- Maintain current trajectory of DSM activities (“Maintain DSM”); and
- Ramp down planned DSM activities in F2014 (“Ramp Down DSM”). Here is it assumed that DSM is ramped down in F2014 for one year but that it takes four years to ramp DSM back up to meet the Initial LNG load.

One way to compare these two strategies is to understand the magnitude of the consequences (i.e., regret) these could result if the DSM activities do not match load growth, as follows:

- Maintain DSM: In this strategy, if Initial LNG load did not materialize, the regret cost is surplus DSM savings that cost more than market price until DSM is ramped down.
- Ramp Down DSM in F2014: In this strategy, if Initial LNG did materialise, the regret cost is contracting new supply if DSM is unable to ramp up in time to
meet LNG load. The lag in ramping DSM back up is primarily due to time required to rebuild relationships and capacity with trade allies and partners in delivering DSM programs and to rebuild confidence among customers.

For the Ramp Down DSM strategy, DSM programs with a F2012 and F2013 levelized total resource cost\(^\text{12}\) (TRC) greater than the average forecast spot market price of $34/MWh\(^\text{13}\), as shown in Figure 6-5 were deemed uneconomic and assumed ramped down in F2014.

**Figure 6-5** Levelized TRC of Electricity Savings from DSM Programs in F2012 and F2013

The Maintain DSM strategy results in surplus energy which is sold to the market, whereas the Ramp Down DSM strategy results in a shortfall in energy which must be made up through supply. Figure 6-6 below shows the volume of surplus and lost energy for the respective options.

\(^{12}\) TRC in this sub-section refers to the net DSM cost prior to the DSM amendments described in section 6.3.4.1.

\(^{13}\) Based on Market Scenario C.
Table 6-5 shows the results of the analysis showing both the TRC and utility cost of Maintain DSM Path and Ramp Down DSM scenarios under the scenario where each is mismatched to the subsequent load growth.

<table>
<thead>
<tr>
<th></th>
<th>Maintain DSM Path, Initial LNG Doesn’t Materialize</th>
<th>Ramp Down DSM, Initial LNG Materializes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Resource Cost</td>
<td>$6</td>
<td>$39</td>
</tr>
<tr>
<td>Utility Cost</td>
<td>($4)</td>
<td>$116</td>
</tr>
</tbody>
</table>

From both a TRC and utility cost perspective, the cost of ramping down DSM now and ramping up later is significantly greater than the cost of maintaining the current DSM path until it is clear whether the LNG load will materialize. Therefore, while the load/resource balance indicates a period of surplus energy in the short term, this
analysis leads to the conclusion that continuing with the current level of effort on
DSM is appropriate in the face of uncertainty regarding LNG load.

6.3.3 Impact of DSM Options on the Load-Resource Balance

The load/resource balance shown in section 2.4 reflects the current DSM target
selected in the 2008 LTAP. As part of this IRP, this target may be adjusted after
considering the five DSM options outlined in Chapter 3. These options represent a
range of DSM savings, up to and including the largest amount of conservation
BC Hydro deemed suitable for resource planning purposes at this time.

Each of the DSM options were assessed a low, mid and high savings level (as
described in Chapter 5) to reflect the uncertainty of forecasting DSM savings. The
impact on the load-resource balance is shown in this section.

The CEA specifies an objective of reducing 66 per cent of load growth by 2020 (i.e.,
F2021) using DSM. Table 6-6 shows the mid savings level associated with the five
DSM options by F2021. Based on normal load growth, all DSM options meet or
exceed the objective. However, when Initial LNG load is included, not even the most
ambitious DSM option that BC Hydro considered suitable for resource planning
purposes meets this objective.

<table>
<thead>
<tr>
<th>DSM Option</th>
<th>Mid Savings in F20214 (GWh/year)</th>
<th>% of Load Growth with Initial LNG</th>
<th>% of Load Growth without Initial LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>8,100</td>
<td>49</td>
<td>67</td>
</tr>
<tr>
<td>2</td>
<td>9,100</td>
<td>54</td>
<td>73</td>
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<tr>
<td>3</td>
<td>9,800</td>
<td>58</td>
<td>78</td>
</tr>
<tr>
<td>4</td>
<td>10,100</td>
<td>59</td>
<td>80</td>
</tr>
<tr>
<td>5</td>
<td>10,200</td>
<td>59</td>
<td>80</td>
</tr>
</tbody>
</table>

Figure 6-7 and Figure 6-8 show the remaining load-resource gaps in the near-term
for a range of gap sizes, all including the initial LNG load, after each of the DSM

14 The DSM Savings are risk-adjusted (mid) and represent the incremental DSM savings beginning from a base
year of F2012.
options. These remaining gap sizes would inform the need for supply side resources.

Figure 6-7 Energy Gap for DSM Options

![Energy Gap for DSM Options Diagram]
6.3.4 Cost Analysis and Comparison of the DSM Options

This section describes the cost analysis of the five DSM Options. It begins with a discussion of the recently amended DSM Regulation under the Utilities Commission Act (UCA) that provides direction to the BCUC on determining the cost-effectiveness of DSM. This is followed by an evaluation of the five DSM options. Thereafter, the cost of the five DSM options is analyzed by creating and comparing portfolios consisting of different DSM options combined with varying amounts of supply side resources. Figure 6-9 illustrates the portfolios created and specifies the assumptions used. The following cost comparisons are presented respective the DSM options:

- Portfolio costs;

- Incremental costs; and
- Differential rate impacts.

**Figure 6-9  Modelling Map – DSM**

**MODELLING MAP – DSM**

<table>
<thead>
<tr>
<th>Uncertainties/Scenarios</th>
<th>Large</th>
<th>Midload, low DSM</th>
<th>Mid</th>
<th>Mid-load, high DSM</th>
<th>Small</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Market Scenario</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Coast Load</td>
<td>Initial LNG Only</td>
<td>Initial LNG &amp; LNG5</td>
<td>Initial LNG, LNG5 &amp; Future Mining</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**IRP Resource Choices**

<table>
<thead>
<tr>
<th>DSM Option</th>
<th>DSM 1</th>
<th>DSM 2</th>
<th>DSM 3</th>
<th>DSM 4</th>
<th>DSM 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site C</td>
<td>Site C in at BND</td>
<td>Site C is an option</td>
<td>Site C is NOT an option</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Thermal Generation</td>
<td>No additional thermal</td>
<td>Yes, additional thermal</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Modelling Assumptions & Parameters**

<table>
<thead>
<tr>
<th>Wind Integration Cost (MW)</th>
<th>$5</th>
<th>$10</th>
<th>$15</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modelling Horizon (yrs)</td>
<td>20</td>
<td>30</td>
<td></td>
</tr>
</tbody>
</table>

**6.3.4.1 Amendments to the DSM Regulation**

Under section 44.2 of the UCA, public utilities must secure B.C. Utilities Commission (BCUC) acceptance of DSM expenditures. Section 44.2 directs the BCUC to consider cost-effectiveness, among other things, in deciding whether to accept a utility’s DSM expenditures. A DSM regulation under the UCA provides direction to the BCUC on the determination of DSM cost-effectiveness. The Province amended the DSM regulation in December 2011.

The amended DSM regulation directs the BCUC to use the TRC Test to determine the cost-effectiveness of DSM and prescribes certain aspects of its calculation. The amended DSM regulation recognizes that DSM can produce a range of benefits. In addition to avoided electric energy costs, these benefits can also include avoided electric capacity costs, avoided natural gas costs and non-energy benefits (NEB)
(e.g., operation and maintenance savings resulting from the installation of an energy efficient measure).

The amended DSM Regulation prescribes the following aspects of the TRC Test calculation:

- Using the amount the BCUC is satisfied represents BC Hydro’s long-run marginal cost (LRMC) of acquiring electricity generated from clean or renewable resources in B.C. to quantify avoided electric energy costs;
- Using LRMC multiplied by 0.5 and converted to a comparable energy value to quantify avoided natural gas costs; and
- Using 15 per cent of the total avoided costs\(^{15}\) as a proxy for the non-energy benefits of DSM or an alternate value proposed by the utility and accepted by the BCUC.

BC Hydro has estimated gas and NEBs in the development of its DSM plans prior to the amended DSM regulation. The key difference between BC Hydro’s (pre-amendment) estimate and the post-amendment estimate is the significant additional benefits of these avoided natural gas costs and NEBs, as prescribed by the recent amendments to the DSM Regulation.

BC Hydro has contemplated the impact of the revised Regulation and its impact on its DSM plans and DSM Options analysis. Firstly, in BC Hydro’s assessment of deliverable cost-effective DSM savings, costs are only one of many factors considered by participants when engaging in conservation behaviour.

Secondly, since the range of DSM Options considered captures all savings suitable for resource planning, the prescribed benefits from the updated regulation are not expected to have a material impact on the available pool of savings considered in this IRP. As such, the amendments to the DSM regulation give extra room for

\(^{15}\) Total avoided costs include avoided electric energy costs, avoided natural gas costs, and avoided electric capacity costs.
BC Hydro to consider additional conservation, but the amount of savings and the
certainty with which these savings can be delivered will be important limiting factors
when determining how much DSM can be relied upon for resource planning
purposes.

For comparison with costs shown in Chapter 3, this IRP represents DSM costs in
three ways\textsuperscript{16}.

- DSM gross cost (i.e., not reflecting any of the “additional benefits”);
- DSM net cost pre-amendment (i.e., reflecting “additional benefits” as estimated
  by BC Hydro); and
- DSM net cost post-amendment (i.e., reflecting “additional benefits” as
  prescribed by the amended DSM Regulation).

Figure 6-10 presents the TRCs averaged within each of the DSM options. They
range from $35 to $50/MWh based on mid-level of savings on a gross cost basis.
The costs shown in Figure 6-10 are different from what was quoted in the analysis
from the 2010 Resource Options Report summarized in Chapter 3 of the IRP for the
following reasons:

- The costs shown here are reflective of the expected savings after uncertainty
  adjustment; and
- Change in amortization period from 10 to 15 years (see section 3.3.4.2).

As Figure 6-10 shows, the prescribed regulations introduce cost adjustments for
additional benefits not previously captured in BC Hydro’s resource planning that
dwarf the costs captured in the Gross TRC and pre-regulation NEB cost
calculations. As a result, including these additional benefits drastically decreases the

\textsuperscript{16} Additional benefits” are referred to as avoided electric capacity costs, avoided natural gas costs and
non-energy benefits. The two net cost views reflect the gross cost net of these “additional benefits”. The
electric energy costs are generally used for comparison with the gross cost or net costs to check for cost
effectiveness. In the analysis where the supply-demand portfolio approach is taken, the supply/electric
energy/IPP costs are accounted for separately.
cost of DSM to the point where, for evaluation purposes, for Option 1, DSM costs net out to almost $0/MWh. To put this into perspective, DSM cost effectiveness is generally tested by comparing these average net costs to BC Hydro’s LRMC ($129/MWh) in a TRC test.

6.3.4.2 Portfolio Cost Analysis

In this section, total portfolio costs (including costs of demand and supply resources) for portfolios with different DSM options are compared. The results shown only reflect DSM net cost post-amendment.

Figure 6-11 below shows the total portfolio costs under Market Scenario C for different DSM options across the large-gap, mid-gap and small-gap scenarios. The expected (i.e., probability weighted) total portfolio costs across different gap sizes

---

17 Here, gap size refers to both Load and DSM levels. As an example, a large gap means high load growth and low DSM savings. See section 5.2.3 for more details on this topic.
are also shown. Option 2 yields the lowest cost portfolio when load is high and DSM underperforms in the large-gap scenario. In the mid-gap scenario, Option 4 yields the lowest cost option. In the small-gap case (when load is low and DSM is over-performing), there is surplus energy and so the costs and benefits of DSM is relative to the electricity export market price. For Market Price Scenario C, export prices are higher than DSM net costs and so Option 5 is the lowest cost portfolio.

![Portfolio Costs across DSM Options (Gap Comparison, Market C Results)](image)

When the expected (probability weighted) outcomes are calculated, the costs of Options 3, 4 and 5 are quite close, with Option 4 yielding the lowest cost option (only $34 million PV difference between Option 3 and 4 out of a $6.4 billion portfolio).

The same analysis in the previous paragraphs was carried out under Market Scenario B with similar results.

### 6.3.4.3 Incremental Cost Analysis

The previous sections that addressed DSM costs alone and portfolio costs of DSM and supply resources were useful to help build an understanding of the cost comparisons. This section aims to compare the resources based on their marginal
value by comparing the incremental cost of going from one DSM option to the next, to the corresponding incremental avoided cost (i.e., benefits) from the supply side.

Over and above providing an additional view to test the cost of DSM, this section is also intended to respond to BCUC Directive 11 from the 2008 LTAP that requires BC Hydro to address, “a methodology for comparing risk-weighted UECs of demand-side measures and of physical supply-side resources”. Given the interrelated nature of the DSM tools (rate structures, codes and standards, and programs), a portfolio of DSM activities is the smallest unit of analysis for determining a long-term DSM target. However, by comparing increments of cost and energy, and by including these levels after the DSM uncertainty assessment was carried out, this analysis comes close to directly addressing this directive.

Focusing on DSM savings uncertainty and leaving load uncertainty aside, Figure 6-12 presents the comparison of incremental DSM costs and corresponding avoided supply-side costs (i.e., benefits) across different DSM levels of savings meeting the same mid load forecast.

In the mid saving case when net cost for DSM is considered, Option 5 is at the crossover point where incremental DSM levelized costs become higher than the incremental levelized avoided cost of supply. That is, going further than DSM Option 4 to DSM Option 5 would involve more DSM costs being incurred than supply costs being avoided relative to Option 3, suggesting stopping at Option 4.

In the high saving case where DSM over performs, the avoided supply cost associated with moving to the next increment is consistently greater than the DSM cost for each increment shown, suggesting to pursue higher DSM option.

In the low saving case where DSM underperforms, the negative levelized DSM costs for the Option 3-4 and Option 3-5 increments are the result of additional DSM costs.

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18 Energy savings from DSM generally increase from DSM Option 1 to 5 but the uncertainty-adjusted difference between Options 4 and 5 is very small. As such, the increment from four to five is not analyzed but instead, the increments from three to four and from three to five are analyzed.
that would be incurred with an associated reduction in the amount of incremental DSM savings (i.e., negative incremental savings). The negative DSM costs indicate it is not worth pursuing DSM Options 4 or 5. In this case, the analysis suggests stopping at Option 2.

Figure 6-12 Incremental DSM Cost Compared to Avoided Supply Cost (Net TRC, post-amendment)

In general, the observations/conclusions made in this analysis are consistent with the portfolio costs analysis. That is, the selected DSM options are the same as the DSM options yielding the lowest cost portfolio in the portfolio cost analysis. Other results from the incremental cost analysis looking at combined load and DSM savings uncertainty, as well as Market Scenario B are included in Appendix 6A.

6.3.4.4 Differential Rate Impact

The DSM differential rate analysis measures the rate impact of portfolios consisting of different DSM Options (Options 1, 3, 4 and 5) relative to a base case which is assumed to be a portfolio with Option 2 (results shown in Figure 6-13). These results were calculated for the mid-gap, Market Scenario C.

Among other variables, portfolios with different DSM options have different DSM-related costs, energy costs and DSM energy savings. These variables sometimes exhibit offsetting rate effects. As an example, incurring costs to reduce energy consumption reduces spending on new supply-side resources. The net effect
on costs depends on the magnitude of the changes of these two costs. However, the revenue required to support this new level of spending must be collected from a reduced energy sales base. This latter effect in and of itself has an upward pressure on rates, and could (as in the case of Option 3) increase rates even though customers’ bills on average are lower.

The analysis suggests that Option 1 generally results in slightly lower average rates than Option 2. Options 3, 4 and 5 all result in higher average customer rates than Option 2 (about 2 per cent by F2021), even though Option 3 is expected to reduce customer electricity bills by $180M over the 20-year planning horizon.

![Differential Rate Impact (DSM Options Relative to DSM Option 2)](image)

BC Hydro maintains the view that PV is a better way to address how DSM options impact costs to customers at a high level; differential rates are only shown for illustrative purposes.

### 6.3.5 Deliverability Risk

A generally accepted definition of risk is “the effect of uncertainty on objectives”. For the IRP, deliverability risk can be thought of as the effect of DSM savings uncertainty on BC Hydro’s IRP objectives.
Tracing through and quantifying the link between DSM savings shortfalls and BC Hydro’s IRP objectives would be exceedingly difficult. This section proceeds in two steps. The first will look at drawing the link between DSM shortfalls and a proxy quantified measure for deliverability risk by identifying the consequences of DSM under delivery. The second is to look at the aspects of deliverability risk not captured by the quantified DSM uncertainty analysis.

Over the full planning horizon, the consequences of supply not meeting demand due to DSM under delivery is most likely cost; if this shortfall occurs with enough warning, an accelerated effort would need to be made on both the DSM and supply side front to secure available resources. Depending on the timing, this could push up costs as it would mean drawing from a smaller pool of resources or paying a premium to access those resources quickly.

Over a shorter timeframe, it is useful to contemplate under delivery in terms of energy and capacity separately. A shortfall in energy that could not be met through purchasing from the domestic market could result in relying on imports to a greater extent than contemplated by the legal self-sufficiency requirements. While this is a serious shortcoming, the focus of this section will be on the capacity side, where a shortfall in electricity at key times would undermine BC Hydro’s fundamental purpose of serving the load.

Estimating the short term consequences of DSM under delivery that lead to capacity shortfalls would be difficult and would likely not add insight to the comparison of DSM options. Consequently, this IRP uses the quantified results from the DSM uncertainty analysis as an imperfect proxy for risk, fully recognizing that a complete analysis of ‘deliverability risk’ would require a full characterization of both uncertainties and consequences.

The jurisdictional review in section 5.2.3 found some support for levels of DSM programs in the range of Options 1 to 3 but also found no comparable jurisdictions that were using a combination of three DSM tools to target savings above Option 2 levels.
Given the above caveats, professional judgement still remains critical in drawing conclusions from the quantitative and qualitative aspects of deliverability risk. 

Figure 6-14 reprises a line of analysis from Chapter 5 showing how much BC Hydro could be surprised if a) there was significant and widespread DSM underperformance, and b) it took several years for BC Hydro to recognize this and react by procuring supply-side resources. In particular, it shows the size of the capacity shortfall in such a situation.

By construction, this figure is updated for Chapter 6 to include both load uncertainty and DSM uncertainty. This shows that deliverability risk increases as the degree of reliance on DSM increases in a portfolio of DSM and supply-side resources. Note here that DSM under delivery is captured in the “large gap” bars above the horizontal axis. Finally, the quantities shown have a 10 per cent chance of occurring. More specifically, these are the expected values of the distribution beyond the P20 and the P80 cut-offs, respectively. Larger extremes are possible, but at lower probability.

While this view is of the uncertainty around meeting the need for capacity, it is important to remember that the SCGTs (peaking units) discussed in section 6.10.3 as contingency resources are 100 MW in size and would take five years for approval and construction. This uncertainty analysis does inform on the relative riskiness of the different DSM options.

While Figure 6-12 captures the quantified aspects of a proxy for DSM deliverability risk, it is important to remember that not all uncertainties have been captured in this analysis. This underscores the need for a qualitative consideration of uncertainty as well as a quantitative one in assessing deliverability risk. In particular:

- Section 5.2.3 noted that there are still some significant information gaps and methodological shortcomings to the quantification of DSM uncertainty; and
- The jurisdictional review in section 5.2.3 found some support for levels of DSM programs in the range of Options 1 to 3 but also found no comparable
jurisdictions that were using a combination of three DSM tools to target savings above Option 2 levels.

Given the above caveats, professional judgement still remains critical in drawing conclusions from the quantitative and qualitative aspects of deliverability risk.

![Graph](image)

**Figure 6-14** Capacity Shortfalls Across DSM Options (MW in F2020)

### 6.3.5.1 Conclusions Regarding Deliverability Risk

There are several observations that can be drawn from this analysis:

- Options 4 and 5 are intrinsically different from Options 1 to 3 and show a substantial but uncertain upside.
• There is a significant degree of uncertainty around a fixed resource plan’s ability to hit its forecast targets several years out, even when just looking at the uncertainties that have been quantified.

• A number of elements have been identified as not being captured in the uncertainty quantification. A prudent approach to energy planning suggests that the quantified uncertainty estimates may understate the deliverability risk of DSM.

• Uncertainty increases with increasing reliance on DSM.

• The recent change of planning criteria from critical water to average water removes some surplus energy that was previously available under all water conditions and acted as a buffer against DSM under delivery in providing a reliable system.

• There is no quantified bright line amongst these DSM options demarcating ‘acceptable’ from ‘too uncertain’ levels of deliverability risk.

• Despite their intrinsic differences, Options 4 and 5 do not show a jump up in deliverability risk compared to Options 1 to 3. This warrants extra caution when applying these quantified results when comparing DSM options.

Given the above observations, deliverability risk will be an important consideration when selecting DSM targets for this IRP.

6.3.5.2 Environmental Footprints

DSM options were also compared based on their estimated environmental attributes. For land and water impacts, this was done using a snapshot of the footprint at the end of the planning period. For GHG emissions, the metric was total emissions over the span of the planning period.

As Table 6-7 below shows increasing the amount of DSM in a portfolio of DSM and IPP resources decreases the impact of that portfolio on Land, Water, Marine and GHG measures; however, these gains were modest in size and almost negligible,
given the precision of the measures used, when comparing adjacent options. More
detailed results can be found in Appendix 6B.

6.3.5.3 **Economic Development Attributes**

DSM options were also compared using economic development impacts. These
results can be found in Table 6-7.

As this table shows, increasing the amount of DSM in a portfolio with DSM and IPP
resources increases measures of economic development. However, these results
are modest and negligible compared to the measures' precision when comparing
adjacent options.

6.3.6 **Full Consequence Table**

Table 6-7 demonstrates the full suite of quantified consequences for comparing
DSM options, summarized at a high level.
Table 6-7  Comparing DSM Options Using Multiple Objectives

<table>
<thead>
<tr>
<th>Measure</th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
<th>Option 4</th>
<th>Option 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Total hectares</td>
<td>12,000</td>
<td>11,161</td>
<td>10,803</td>
<td>8,622</td>
<td>8,304</td>
</tr>
<tr>
<td>Affected stream length km</td>
<td>223</td>
<td>205</td>
<td>214</td>
<td>168</td>
<td>164</td>
</tr>
<tr>
<td>Marine (valued ecological features) Total hectares</td>
<td>56</td>
<td>49</td>
<td>42</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>GHG CO2e ('000 t)</td>
<td>5,752</td>
<td>5,550</td>
<td>5,558</td>
<td>5,237</td>
<td>4,965</td>
</tr>
<tr>
<td>GDP $M PV</td>
<td>15,300</td>
<td>15,800</td>
<td>16,400</td>
<td>17,400</td>
<td>18,100</td>
</tr>
<tr>
<td>Employment Total FTEs</td>
<td>272,000</td>
<td>276,800</td>
<td>282,700</td>
<td>290,700</td>
<td>299,300</td>
</tr>
<tr>
<td>Gov't Revenue $M PV</td>
<td>2,200</td>
<td>2,220</td>
<td>2,300</td>
<td>2,400</td>
<td>2,500</td>
</tr>
<tr>
<td>Quantified Deliverability Risk MW between mid and large gap F2020</td>
<td>1,077</td>
<td>1,135</td>
<td>1,200</td>
<td>1,290</td>
<td>1,313</td>
</tr>
<tr>
<td>Net Cost (Post Amendment) $M NPV (expected)</td>
<td>7,109</td>
<td>6,563</td>
<td>6,444</td>
<td>6,410</td>
<td>6,446</td>
</tr>
</tbody>
</table>

As this shows, moving from DSM Option 2 (roughly the current level of DSM) to a lower level of DSM increases costs for no discernible benefit.

Moving from DSM Option 2 to Option 3 delivers some potential gains in avoiding the environmental footprint of supply-side resources as well as some modest economic development benefits. However, these results are small to negligible given the precision of the modelling.

Moving from Option 2 to Option 3 also reduces expected cost, but this increases deliverability risk (i.e., reduces certainty around meeting load requirements).

As Table 6-7 demonstrates, moving from Option 2 to Options 4 or 5 would further increase the economic development benefits expected and reduce the environmental footprint, particularly when measured at the end of the 20-year planning period as these environmental criteria are portrayed.

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19 In this table, Option 2 is selected as a basis of comparison. Green shading indicates an alternative performing substantially better on that criterion, red shading indicates an option performing substantially worse on that criterion. This colour scheme is meant as a high level guide only to help focus on key differences.
The benefits of moving to higher levels of DSM beyond Option 3 to Options 4 or 5 are offset by an increase in deliverability risk. The context of this increase must be considered:

- There is already large uncertainty in load growth;
- Moving from critical water to average water planning criteria has removed some of the surplus energy that was previously available under all water conditions and acted as a buffer against a large-gap scenario in providing a reliable system;
- Given that the quantification of uncertainty only partially captured issues of concern (see Chapter 5), it may be that uncertainty of DSM savings is even larger than portrayed; and
- Options 4 and 5 are novel in their combination of DSM tools, a uniqueness that was not fully expressed in the quantification of uncertainty. This magnifies the uncertainty of moving to DSM targets that are outside of past experience.

### 6.3.7 Conclusions

Despite the near-term energy surplus situation, BC Hydro should maintain its current trajectory of DSM activities as opposed to ramp down its DSM activities in face of load uncertainty. The potential regret as a result of ramping down is more costly.

The five DSM options cover all potential DSM savings suitable for planning purposes. But given significant load growth in the industrial sector, including initial LNG demand, even the most ambitious DSM option that BC Hydro identified did not meet the 66 per cent DSM savings objective.

Increasing DSM targets from Option 2 to Option 3 is a cost effective balance of decreasing ratepayer impacts and securing environmental and economic development benefits versus increasing deliverability risk in the face of significant load and DSM savings uncertainty. This conclusion should be revisited if the investment decision for initial LNG is not confirmed because the difference in energy
savings between Option 2 and 3 would result in energy surplus and the incremental cost from Option 2 to 3 is likely more costly than market electricity price.

Moving beyond Option 3 to higher levels of DSM are not recommended because of further increased deliverability risk in the face of significant load and DSM savings uncertainty in pursuing an untried methodology and reduced buffer to react under average water planning criteria in providing a reliable system.

The upside to Options 4 and 5 is extremely attractive, and so BC Hydro should advance work on elements of the more aggressive codes, standards, and conservation rate structures to better understand how to secure their upside savings potential while avoiding their downside uncertainty.

To support exploring the upside potential of Options 4 and 5, BC Hydro should continue to pursue collaborative opportunities with government to advance codes, standards, and conservation rate structures.

Conclusions in this DSM section support Recommended Actions Nos. 1 and 2 categorized under “Conserve More” as described in section 9.4.1 of Chapter 9.

6.4 Site C

6.4.1 Introduction

The proposed Site C Clean Energy Project (Site C) is described in Chapter 3. It would provide up to 1,100 MW of dependable capacity, and approximately 4,700 GWh and 5,100 GWh of firm energy and average energy per year respectively. The earliest in-service date for the first of six units at Site C is estimated to be December 2020 (i.e., F2021) but Site C’s energy and capacity contribution is not fully available until F2022 (i.e., 2021) as modelled in the portfolio analysis.

Site C is currently in the early stages of a cooperative federal-provincial environmental assessment, which includes a joint review panel process. Due to uncertainty of the regulatory process, the earliest in service date for Site C may be
delayed (this timing uncertainty is addressed in the contingency discussion in section 6.10.

Site C was identified as a cost-effective resource option in the 2008 LTAP and continues to be shown as relatively low unit cost this IRP (Chapter 3), providing significant clean energy and capacity contributions. The key IRP question for Site C is:

- Does Site C continue to be cost-effective compared to other available resource options? This includes a comparison of the non-financial attributes between portfolios with and without Site C.

6.4.2 Site C Compared to Other Clean Resources

To assess Site C’s cost-effectiveness relative to other clean resources, Site C was provided as an option for the System Optimizer to select under a range of load-resource gaps (small, mid, large) and Market Scenarios. In addition, corresponding portfolios without Site C were explicitly created for comparison purposes. Figure 6-15 illustrates the assumptions used to create these portfolios.
Table 6-8 provides details of the selection of the Site C project by the System Optimizer, as well as the difference in portfolio present value between portfolios with and without Site C.
### Table 6-8 Site C Selection and Cost Advantage

<table>
<thead>
<tr>
<th>Gap Sizes</th>
<th>Market Scenarios and Likelihood</th>
<th>PV Difference between Portfolios With and Without Site C (PV, $2011 million)</th>
<th>Year Site C Selected</th>
<th>Weighted Average across Market Scenarios (PV Difference, $ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large 10%</td>
<td>A 5%</td>
<td>859</td>
<td>2021 (F2022)</td>
<td>615</td>
</tr>
<tr>
<td></td>
<td>B 30%</td>
<td>653</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>C 40%</td>
<td>570</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>D 5%</td>
<td>823</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>E 20%</td>
<td>532</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td>Mid 80%</td>
<td>A 5%</td>
<td>634</td>
<td>2021 (F2022)</td>
<td>199</td>
</tr>
<tr>
<td></td>
<td>B 30%</td>
<td>338</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>C 40%</td>
<td>71</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>D 5%</td>
<td>583</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>E 20%</td>
<td>42</td>
<td>2021 (F2022)</td>
<td></td>
</tr>
<tr>
<td>Small 10%</td>
<td>A 5%</td>
<td>118</td>
<td>2024 (F2025)</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>B 30%</td>
<td>8</td>
<td>2029 (F2030)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>C 40%</td>
<td>0</td>
<td>Not selected</td>
<td></td>
</tr>
<tr>
<td></td>
<td>D 5%</td>
<td>68</td>
<td>2026 (F2027)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>E 20%</td>
<td>0</td>
<td>Not selected</td>
<td></td>
</tr>
</tbody>
</table>

Site C continues to be a cost-effective resource compared to other clean resource options in the majority of cases. In all large- and mid-gap cases, Site C is selected by the System Optimizer at its earliest in-service date, regardless of market scenarios.

In the small-gap case, Site C is selected in three of the five Market Scenarios. The small gap is insufficiently large to require a project the size of Site C; however Site C is selected in the three Market Scenarios where higher market electricity prices would justify the early construction due to revenue from the sale of Site C’s surplus energy output in the market. In the two small-gap, low electricity price Market

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20 The small-gap case is one where there is no load-resource gap until almost the end of the planning period because of a small increase in electricity demand combined with high savings from DSM. The small-gap case has a low likelihood of occurrence.
Scenarios where Site C is not selected, a small number of alternative energy resources are preferred.

6.4.2.1 Sensitivity to Assumptions on Capacity Options

As BC Hydro has nearly exhausted all of its available options that provide low cost hydro peaking capacity (see section 6.10), the next available clean dependable capacity-rich supply alternative to Site C is pumped storage (the capacity proxy/alternative modelled in the IRP portfolio analysis as described in section 5.3). Site C compares favourably to pumped storage as pumped storage consumes energy (approximately 30 per cent through its pump/store/generate cycle), is more costly and has high development uncertainty. In the portfolio analysis described in section 6.4.2, the System Optimizer always picked Site C instead of pumped storage units in the Lower Mainland even though the additional cost of pumped storage associated with the 30 per cent energy losses were not included in the analysis.

As concluded in section 6.2, using gas-fired generation as a dependable capacity resource is one of the higher value applications of the limited non-clean headroom given the 93 per cent clean objective. To test the effect of using the 7 per cent non-clean headroom on the need for Site C, portfolios across a range of market price scenarios were created allowing System Optimizer to select Site C or natural gas peakers (SCGTs) up to the 7 per cent non-clean headroom. Site C was selected at its earliest in service date in most scenarios except in the low gas and electricity price scenarios where its selection was delayed to 2027 (F2028).

Supplying dependable capacity with gas peakers rather than Site C would quickly use up the 7 per cent non-clean headroom, and as a result forego BC Hydro’s ability to use gas for higher value applications (e.g., forego BC Hydro’s key viable near-term contingency capacity resource). Furthermore, the 7 per cent non-clean headroom is not sufficient to meet capacity need in the planning horizon, requiring

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21 As described in section 6.10, there is further capacity need after the last low cost hydro peaking capacity addition, Revelstoke 6.
additional clean capacity. Given the availability of a cost-effective energy and capacity resource like Site C, the option value of gas should be maintained.

6.4.3 Ancillary Benefits

Site C also provides ancillary benefits to the electric system, including shaping and firming capability and capability to integrate intermittent resources (most of these benefits have not been modelled in System Optimizer). As discussed in section 6.8, the ability for the existing hydro system to shape, firm and integrate resources is limited. In the large-gap case where the need for resources is great, Site C’s integration capability may be required at its earliest in-service date.

6.4.4 Environmental Attributes

Portfolios with and without Site C described in section 6.4.2 were compared based on their environmental attributes. For land and water footprints, this IRP takes a snapshot of the annual footprint at the end of the planning period. Full details of the measures can be found in Appendix 6B. Only a high level summary of measures that are useful for comparing options are presented for IRP questions. For simplicity, only one set of portfolio results is displayed in Table 6-9 (mid-gap, DSM 2, Market Scenario C).

Note that the environmental attributes for Site C are unique within the IRP given the advanced level of project definition for Site C and accompanying accuracy in the project footprint. The portfolios without Site C are populated with forecast, generic, “typical” projects with estimated footprints.

**Land footprint:** A portfolio meeting load growth that includes Site C generally has a larger land footprint than a portfolio of resources not using Site C. However, the difference between the portfolios is less than the full 5,300 ha Site C inundation area as a portfolio without Site C must employ different supply-side resources to meet energy and capacity needs, which also have environmental footprints. There is also the potential for portfolios without Site C in some large-gap cases to yield higher
footprints than portfolios with Site C, depending on what mix of supply-side 
resources are replacing Site C.

**Freshwater footprint:** A portfolio meeting load growth that includes Site C generally
has a larger freshwater footprint than a portfolio of resources not using Site C. As
with the land footprint, there is the potential for portfolios without Site C to yield
higher footprints than portfolios with Site C.

**Reservoir aquatic area:** The reservoir aquatic measure is meant to capture the
effect of the creation of a reservoir. Portfolios with Site C will show reservoir
creation, while portfolios without Site C will not.

Pumped storage, an alternative capacity-rich option and net energy consumer, is
assumed to occur on existing water bodies with no reservoir footprints for this
modelling analysis. Since no pumped storage project has ever been sited in B.C.,
this is a data gap; future environmental assessment of this option may revise this
estimate.

**Other Environmental Attributes:** Due to the nature of the Site C resource, there
are no significant differences in the Marine, Local Air Emissions, and GHG attributes
between portfolios with and without Site C.

### 6.4.5 Economic Development Attributes

Portfolios with and without Site C described in section 6.4.2 were compared based
on their economic development attributes. Table 6-9 below shows how these
measures rank the two options considered. For simplicity, only one set of portfolios
from those described in section 6.4.2 is compared: mid-gap, DSM 2, Market
Scenario C. Full details of measures considered can be found in Appendix 6B.

As this table shows, portfolios with Site C generally increase measures of economic
development as compared to portfolios without Site C.
### 6.4.6 Full Consequence Table

Table 6-9 shows the full suite of environmental, economic development, and financial impacts used for comparing a portfolio with and without Site C. These measures are shown at a high level, Appendix 6B breaks these out into more detail.

<table>
<thead>
<tr>
<th>Measure</th>
<th>Without Site C</th>
<th>With Site C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land</td>
<td>Total hectares</td>
<td>9,324</td>
</tr>
<tr>
<td>Affected stream length</td>
<td>km</td>
<td>210</td>
</tr>
<tr>
<td>Marine (valued ecological features)</td>
<td>Total hectares</td>
<td>54</td>
</tr>
<tr>
<td>Reservoir Aquatic Area</td>
<td>hectares</td>
<td>0</td>
</tr>
<tr>
<td>Total GDP</td>
<td>$ million PV</td>
<td>8,900</td>
</tr>
<tr>
<td>Employment</td>
<td>Total FTEs</td>
<td>185,700</td>
</tr>
<tr>
<td>Gov't Revenue</td>
<td>$ million PV</td>
<td>1,400</td>
</tr>
<tr>
<td>Cost</td>
<td>$ million PV (expected)</td>
<td>8,632</td>
</tr>
</tbody>
</table>

As this table shows, the inclusion of Site C as an option within a broader portfolio of supply-side and demand-side resources reduces expected cost (averaged across all market scenarios, all gap sizes) and boosts economic development. However, while doing this, this portfolio of resources has a larger footprint on land due to the creation of a reservoir.

### 6.4.7 Conclusions

The IRP analysis demonstrates that the Site C Clean Energy Project continues to be a cost-effective resource compared to other clean resource options. Site C decreases overall costs to meet B.C.’s energy needs when compared to portfolios that exclude Site C. Site C would be needed at its earliest in-service date across a variety of market and load growth conditions. This conclusion is not dependent on the load from the proposed Initial LNG facilities.

Site C supports the province’s clean energy and GHG reduction objectives that have guided this plan.
In addition to providing energy and capacity, Site C also provides ancillary benefits
to the electric system including shaping and firming capability, and capability to
integrate intermittent resources.

Although generally the IRP analysis shows greater environmental footprints when
portfolios were modelled with Site C than portfolios modelled without Site C, the
economic and ancillary benefits continue to support the recommendation to build
Site C.

The development of the Site C project is subject to environmental certification and
fulfillment of the Crown’s duty to consult and, where appropriate, accommodate
Aboriginal groups.

Conclusions in this Site C section support Recommended Action No. 4 categorized
under “Build and Reinvest More” as described in section 9.4.2 of Chapter 9.

6.5 North Coast

6.5.1 Introduction

The North Coast refers to the area in Northwest B.C. connected to the rest of the
BC Hydro system via a 500 kV transmission line from Prince George to Terrace.
From Terrace, the area is primarily served by two 287 kV transmission lines to
Kitimat and Prince Rupert. When the 287 kV Northwest Transmission Line (NTL)
project is completed in May 2014, service will be extended north to Bob Quinn,
interconnecting the Forrest Kerr hydroelectric project, several mines and remote
communities, including First Nations.

As described in Chapter 2, the proposed initial LNG facilities and significant mining
loads are expected in this area. To serve the mid load forecast with these facilities,
new clean energy from the system is required as well as transmission upgrades,
including series compensation on the transmission line from Prince George to
Terrace and other regional upgrades. These requirements are discussed further in
sections 6.8 and 6.9 respectively. Accordingly, BC Hydro is preparing to meet even
greater demand.

The North Coast area poses significant load uncertainties for BC Hydro as
discussed in Chapter 2. In addition to the LNG and mining loads that are included in
the mid load forecast, there is significant potential incremental load from other LNG
facilities and mines. While these loads may not materialize if the projects don’t go
ahead or if the project proponents decide to use natural gas to meet their energy
needs rather than electricity, it is prudent for BC Hydro to consider these load
scenarios in developing an IRP. In analyzing these load scenarios, the energy and
transmission upgrades requirements described in the previous paragraph are
assumed already committed.

The key IRP question for the North Coast is:

- What is BC Hydro’s strategy to prepare for further significant load growth in the
  North Coast without load certainty at this time?

To address this question, the IRP analyzed two bookend supply options to meet
each of the two load scenarios incremental to the mid load forecast with Initial LNG.

Lastly, further to the discussion of gas-fired generation in section 6.2, this section
describes an analysis on the locational value of siting gas-fired generation in the
North Coast.

### 6.5.2 North Coast Incremental Load Scenarios

Two load scenarios incremental to the mid load forecast were developed based on
interconnection requests that BC Hydro has received from mining and LNG
proponents. They are:

- LNG3 scenario: BC Hydro constructed a scenario with a third potential project
  (referred to here as LNG3) on the North Coast, also located at Kitimat. As
described in section 2.4, this LNG3 project together with associated pipeline
  compression load is assumed to add 6,400 GWh/year and 800 MW in F2020
• LNG3 with High Mining scenario: The objective of this load scenario is to test higher mining load in the North Coast region in addition to LNG3, while restricting mining load further North by the capability of NTL. The mid load forecast described in Chapter 2 only includes approximately 200 MW of load in the NTL region, which is the probability weighted sum of mining loads in this region. Although the full mining load potential far exceeds the estimated NTL capacity of about 465 MW, total mining loads interconnecting to NTL is assumed capped at NTL’s capability in this scenario. As described in section 2.5, the high mining scenario adds approximately 70 GWh/year and 20 MW in F2014, growing to approximately 2,000 GWh/year and 270 MW in F2018 and beyond of demand to the LNG 3 load scenario.

6.5.3 Analysis of North Coast Supply Options

Supplying electricity (especially capacity) to the North Coast to meet the incremental load scenarios poses unique challenges as the magnitude and timing of the incremental loads tests the capacity of transmission and the capacity potential of new local generation resource. The area is supplied through a single transmission line which, even after the transmission upgrade required to meet base load requirements, will be close to fully loaded after Initial LNG comes online. As well, local resource options made up mostly by run-of-river hydro, wind and some biomass provide limited dependable generation capacity potential.

Two bookend options for BC Hydro to supply the North Coast incremental load, while meeting the 93 per cent clean objective, were analyzed as set out below.

Supply Option A: Clean energy backed up by North Coast SCGTs as required.

• With this supply option, the energy to meet incremental North Coast load would be mostly sourced in the North Coast region. Incremental capacity need would be met by SCGTs in the North Coast. The gas capacity needed by year for the
two load scenarios is shown in Table 6-10 and is close to using up the 7 per cent non-clean headroom.

<table>
<thead>
<tr>
<th>Calendar Years</th>
<th>LNG3 Load Scenario</th>
<th>LNG3 and High Mining Load Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>700</td>
<td>1,100</td>
</tr>
<tr>
<td>2020</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td>2025</td>
<td>400</td>
<td>300</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,500</strong></td>
<td><strong>1,800</strong></td>
</tr>
</tbody>
</table>

- With a single transmission line connection to the integrated system, this option poses local integration challenges. Although the technical feasibility of this option is confirmed, it is expected to result in a less reliable and less stable system compared to Supply Option B.

**Supply Option B**: Clean energy via new transmission to the integrated system.

- This supply option requires additional transmission connection to the integrated system from Prince George to Terrace and from Terrace to Kitimat. Incremental capacity need is met by pumped storage units in the Lower Mainland via the new transmission connection. The energy needed to meet incremental North Coast load could be a combination of energy from the system or locally, whichever makes more economic sense.

- Given additional transmission connection to the integrated system, this option enhances system reliability over Option A. However, building a high voltage transmission line to meet load potentially as early as F2019 poses development challenges and is already on critical path.

For both supply options, the acquisition of the required energy and capacity is on critical path. The potential LNG3 load has a significant potential energy requirement
(6,000 GWh to 9,600 GWh) starting in F2020 to F2021. This amount is larger than any of BC Hydro’s previous clean energy calls and to meet an in-service date of F2020, working back, the planning and design of an acquisition process would need to begin as early as F2013.

Figure 6-16 illustrates the assumptions used in creating the portfolios for analysis. The portfolio costs of the two supply options are compared in Table 6-11.

Figure 6-16  Modelling Map – North Coast

MODELLING MAP – NORTH COAST

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22 Supply Option A needs less clean energy because of energy contribution from gas peakers.
Table 6-11 shows that Supply Option B is higher cost than Supply Option A for meeting both North Coast incremental load scenarios analyzed; however, it yields a more reliable and stable system. Furthermore, the cost difference can be reduced if gas-fired generation was built in the system to provide capacity via the new transmission connection instead of pumped storage as discussed in section 6.5.4.

In selecting a preferred/cost effective supply option, BC Hydro needs to consider factors such as customer preferences including stability and reliability considerations, and other development risks/challenges. Further studies, including the studies of hybrids of the two bookend supply options, are required before a preferred option can be chosen.

The transmission and power acquisition requirements for the supply options are already on critical path but the load requirements are still uncertain. In addition, BC Hydro will have to keep both supply options alive before a preferred option is chosen in order to serve these loads in time. Further discussions on the timing and need for the associated transmission and energy acquisition requirements are included in section 6.9 and 6.8 respectively.

6.5.4 Locational Value of Gas-Fired Generation in North Coast

As discussed in section 6.2, siting sufficient gas in the North Coast to meet the load scenarios incremental to the Initial LNG facilities may avoid the need for additional transmission line from Prince George to Terrace. To better understand the locational
value of siting gas within the 7 per cent non-clean headroom, the portfolio costs of siting gas in the Kelly Lake region versus in the North Coast region were compared. The analysis was based on Market Scenario C and the LNG3 load scenario.

Table 6-12 shows that siting gas-fired generation in the North Coast could have a benefit of $38 million. If a smaller incremental load is considered, the potential cost saving of siting gas in the North Coast would increase because fewer gas units are required compared to a relatively standard size and cost of a bulk transmission line.

<p>| Table 6-12 Cost Comparison of Gas-Fired Generation at Kelly Lake and the North Coast (PV, $ million, $2011) |</p>
<table>
<thead>
<tr>
<th>Portfolio Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) North Coast: Clean energy backed up by gas capacity in North Coast (same as Supply Option A)</td>
</tr>
<tr>
<td>(2) Kelly Lake: Clean energy and gas energy and capacity from the system via transmission</td>
</tr>
<tr>
<td>(2) – (1) Benefit of siting gas in the North Coast</td>
</tr>
</tbody>
</table>

6.5.5 Environmental Footprints

The options for serving future load growth in the North Coast region were also compared by their environmental footprints. Table 6-13 shows some high level results of such a comparison based on the LNG3 scenario. Appendix 6B presents more details regarding these results and also shows the results for the LNG3 and High Mining Loads scenario.

As shown in Table 6-13, building transmission lines to provide access to clean resources located across the province has a greater footprint on land and water than using SCGTs situated in the North Coast to meet capacity needs. However, this is counterbalanced by the decrease in local air contaminants and GHG emissions from avoiding the use of local thermal generation for capacity.

6.5.6 Economic Development Attributes

The supply options for the LNG3 scenario were also compared on their effects to economic development. As Table 6-13 shows, building transmission to access clean
resources leads to greater contributions to economic development than relying on clean resources backed by gas plants.

### 6.5.7 Full Consequence Table

Table 6-13 below shows a high level summary of the collection of quantified impacts used to compare different ways to meet North Coast LNG3 load.

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

As this table shows, relying on clean energy resources backed by SCGTs for capacity is a lower cost option that also avoids the footprint of new transmission lines. However, this option would also have the impact of increasing local air contaminants, work contrary to the provincial goals of reducing GHG emissions, and also reduce economic development compared to its alternative.

### 6.5.8 Conclusions

While cost is a key consideration, the choice of preferred supply options for meeting load growth in the North Coast incremental to load forecast with Initial LNG would be based upon customer preferences for supply including stability and reliability considerations, and development risks/challenges. This IRP has not landed on a
preferred supply option but recommends further studies, including studies of hybrids of the two bookend options.

Given the transmission (from Prince George to Terrace to Kitimat) and power acquisition (roughly additional 10,000 GWh by F2021 and gas units in North Coast) requirements from the two supply options to meet potential incremental loads are on critical path, BC Hydro should proceed with planning, preliminary design and consultation activities associated with these requirements in order to maintain the viability of both supply options, and manage any risks associated with load uncertainty.

Conclusions in this North Coast section support Recommended Actions Nos. 11, 12 and 13 under the “Prepare for Potentially Greater Demand” category as described in section 9.4.4 of Chapter 9.

6.6 Fort Nelson Supply and Electrification of the Horn River Basin

6.6.1 Introduction

Three Horn River Basin (HRB) scenarios (high, mid and low), along with the Fort Nelson mid-load forecast, were used in the IRP analysis.

The key IRP questions to address Fort Nelson supply and the electrification of the HRB are:

- What actions are required to meet the load growth in Fort Nelson considering the solution for Fort Nelson may be influenced by the HRB industrial loads and supply options?

- What is BC Hydro’s strategy to prepare for significant potential load growth in the combined Fort Nelson and Horn River Basin regions? 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 carbon dioxide (CO$_2$) that is produced in the HRB under various gas production/energy supply scenarios and reduction opportunities.

An additional consideration is the effect of electricity service to the HRB on the provincial 93 per cent clean energy objective; and the potential for additional benefits related to electricity supply to the HRB, such as access to new clean energy resources.

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

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

### 6.6.2 Load Scenarios

Three HRB electric load scenarios (hig, mid and low), along with the Fort Nelson mid load forecast, were used in the IRP analysis.

Details of the Fort Nelson load forecasts and the HRB electrification load scenarios are provided in section 2.5.2 and Appendix 2E. The Fort Nelson load forecast is driven by a combination of residential, commercial and industrial growth; while the HRB scenarios are driven by potential gas production levels.

### 6.6.3 Alternative Supply Strategies

Three basic supply strategies were considered for the Fort Nelson/HRB analysis. They are:

- Alternative 1: Supplying clean electricity to these regions by connecting these regions to the BC Hydro integrated system;
• Alternative 2: Supplying electricity from within the region; and
• Alternative 3: Supplying just Fort Nelson within the region (no supply service to the HRB).

Some of these basic alternative supply strategies were broken down further for a total of nine alternative supply strategies considered in the analysis, as described in Table 6-14 below.
### Table 6-14  Summary of Fort Nelson/HRB Electricity Supply Strategies

<table>
<thead>
<tr>
<th>Supply Alternative</th>
<th>Strategy Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Alternative 1</strong>&lt;br&gt;BC Hydro Integrated System</td>
<td>Supply Fort Nelson/HRB with clean energy from the BC Hydro integrated system. With this strategy; a new transmission line would be built from Peace Region to Fort Nelson and then up to the HRB. This would connect Fort Nelson and the HRB to BC Hydro’s existing integrated system.</td>
</tr>
</tbody>
</table>
| **Alternative 2A**<br>Regional-Based: One Fort Nelson/HRB Network | With this strategy, the two regions of Fort Nelson and HRB would be connected via a new transmission line. Generation could be developed in one area to service both regions or plants could be dispersed in both regions. Various gas-fired generation options were examined, along with the option of combining local clean and gas-fired generation resources.  

The different options considered as part of this strategy include:

2A1: Supply with gas co-generation  
   (1) One co-generation plant in Fort Nelson  
   (2) Two co-generation plants in Fort Nelson and HRB  

2A2: Supply with CCGT in Fort Nelson  

2A3: Supply with local clean energy (wind) and backed by SCGT in Fort Nelson. |
| **Alternative 2B**<br>Regional-Based: HRB alone | With this strategy, both regions are supplied separately and from within their own region. A gas-fired cogeneration plant would service the HRB, and a new SCGT would service Fort Nelson or increased service from Alberta.  

The different options considered as part of this strategy include:

2B Supply HRB as a separate network with a gas co-generation plant supply Fort Nelson with either:
   (1) a new SCGT in Fort Nelson, or  
   (2) increased transmission service from Alberta. |
| **Alternative 3**<br>Business-as-Usual (BAU) | With this strategy, the HRB region is not serviced by BC Hydro but instead companies would self-supply. A new SCGT would service Fort Nelson or increased service from Alberta.  

The different options considered as part of this strategy include:

3: No service to HRB; supply Fort Nelson as BAU:
   (1) a new SCGT in Fort Nelson  
   (2) increased transmission service from Alberta |
6.6.4 Fort Nelson/HRB Analysis

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

The modelling for the Fort Nelson/HRB analysis is done over a very long period (to 2060), which is effectively 43 years from the assessed earliest in-service date of new transmission needed to connect Fort Nelson/HRB to BC Hydro’s integrated system. This approach allows for the testing of whether facilities, such as transmission lines, may become stranded, and if the effect, when considered today, is material. It also provides insight into how the overall system might operate, and issues that might arise.

Where relevant, the three load scenarios identified earlier were analyzed across Market Scenarios C, B and D and are presented for each of the strategies analyzed.

6.6.4.1 Economic Analysis

The base metric for much of the Fort Nelson/HRB economic analysis is the present value of the cost to serve the electricity load. The costs are expressed in present value (PV) in 2011$ for the period 2014 to 2060. Other assumptions include:

- For co-generation plants, BC Hydro sells heat at 85 per cent of producer avoided cost;
- BC Hydro operates any required transmission networks; and
- The benefits of interconnecting the North Peace River cluster, estimated at $150 million as discussed in section 6.9.4, are used to offset the cost of NETL.

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23 The Market Scenario sequence of C, followed by B, followed by D, is to show the results in the order from the lowest market price scenario to the highest market price scenario.
Total costs for the above combination of scenarios and strategies are presented in Table 6-15. It is important to note that comparing these costs cannot be done in isolation of the overall context, and other analysis. There is a significant difference in loads served across some of the strategies, and such differences must be considered when making any conclusions based in whole or in part on these costs.

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

- Where BC Hydro is serving the full Fort Nelson/HRB region, (Columns [1] – [6]):
  - A supply strategy based on clean energy from the BC Hydro integrated system (Alternative 1, Column [1]) is relatively more expensive than other strategies under Market Scenario C, while this strategy is at or near the lowest cost under Market Scenario B and D.
  - A local clean energy strategy of wind, backed by SCGTs (Alternative 2A3, Column [2]) is never the low-cost strategy.
  - Strategies relying on gas-fired generation are clearly the lowest cost under Market Scenario C; similar to, but generally somewhat higher in cost than, the BC Hydro system clean energy strategy (Column [1]) under Market Scenario B; and higher cost than the BC Hydro system clean energy strategy (Column [1]) under Market Scenario D.
  - Within the gas-fired generation strategies, the CCGT strategy (Column [5]) is in the middle of the cost range. This is because it does not rely on heat sales, as co-generation facilities do. Co-generation strategies with the highest heat sales load (in this set of analysis represented by Alternative 2A1(2), Column [4]), show up as having the best cost characteristics.

- Where BC Hydro is serving Fort Nelson/HRB separately with different regional networks (the HRB strategy Alternative 2B), (Column [6]):
  - Analytical trends for co-generation are similar to the full Fort Nelson/HRB network, but the costs are allocated across somewhat less load.
### Table 6-15
BC Hydro’s Total Cost to Serve Fort Nelson and HRB (PV $ million)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>High Load Scenario; Market Scenario C</td>
<td>9,079</td>
<td>8,488</td>
<td>7,234</td>
<td>6,265</td>
<td>7,351</td>
<td>6,434</td>
<td>354</td>
</tr>
<tr>
<td>High Load Scenario; Market Scenario B</td>
<td>9,325</td>
<td>10,777</td>
<td>11,528</td>
<td>9,757</td>
<td>10,813</td>
<td>10,045</td>
<td>506</td>
</tr>
<tr>
<td>High Load Scenario; Market Scenario D</td>
<td>9,472</td>
<td>12,579</td>
<td>14,893</td>
<td>12,493</td>
<td>13,536</td>
<td>12,876</td>
<td>638</td>
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<tr>
<td>Mid Load Scenario; Market Scenario C</td>
<td>5,068</td>
<td>5,174</td>
<td>4,214</td>
<td>3,850</td>
<td>4,367</td>
<td>3,650</td>
<td>354</td>
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<td>Mid Load Scenario; Market Scenario B</td>
<td>5,313</td>
<td>6,563</td>
<td>6,650</td>
<td>5,999</td>
<td>6,467</td>
<td>5,596</td>
<td>506</td>
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<tr>
<td>Mid Load Scenario; Market Scenario D</td>
<td>5,461</td>
<td>7,654</td>
<td>8,548</td>
<td>7,677</td>
<td>8,112</td>
<td>7,115</td>
<td>638</td>
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<tr>
<td>Low Load Scenario; Market Scenario C</td>
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<td>2,716</td>
<td>2,139</td>
<td>1,810</td>
<td>2,139</td>
<td>1,827</td>
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<td>3,335</td>
<td>3,208</td>
<td>2,433</td>
<td>3,208</td>
<td>2,641</td>
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<tr>
<td>Low Load Scenario; Market Scenario D</td>
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<td>3,825</td>
<td>4,047</td>
<td>2,927</td>
<td>4,047</td>
<td>3,282</td>
<td>638</td>
</tr>
</tbody>
</table>

### 6.6.4.2 GHG Emission Production Analysis

In this section, the amounts of vented CO₂ are analyzed as well as the costs and benefits of moving to supply strategies with clean energy.

---

24 For Fort Nelson supply, the lower of the two cost estimates was used. Refer to section 6.6.4.4 for more information.
The raw natural gas in the HRB has a relatively high concentration (12 per cent) of CO₂ which is currently removed from the natural gas during processing and vented to the atmosphere. In the case of the overall Fort Nelson/HRB analysis, the results include vented CO₂ from both formation and combustion processes. In the case of BC Hydro’s share, the results are only for combustion CO₂.

The modelled results for GHG production, as measured by volume in megatonnes (MT)/year of vented CO₂, are insensitive to different Market Scenarios, because the resources and dispatch are the same for each strategy analyzed.

**Overall Fort Nelson/HRB GHG Emission Production**

As shown in Table 6-3, GHG emission production is highest with a strategy where the HRB development proceeds on a BAU track, where producers self-supply their electricity and heat requirements, and there is no CO₂ sequestration (Column [8]). In this strategy, the PV of MT of GHG is 216 MT, 154 MT and 78 MT for the high, mid and low load scenarios respectively.

If carbon capture and sequestration of formation CO₂ could be successfully implemented, those amounts can be reduced to 98 MT, 70 MT and 36 MT for the high, mid and low scenarios respectively (Column [7]). This indicates that approximately 55 per cent of the overall GHG vented can be eliminated without BC Hydro’s involvement, again assuming that sequestration can be successfully implemented.

With BC Hydro’s involvement by supplying the region clean energy via the integrated system, the overall vented GHG can be further reduced to 61 MT, 48 MT and 25 MT for the high, mid and low scenarios (Column [1]). This represents a cumulative reduction of approximately 70 per cent (middle of Table 6-16), or an incremental improvement after sequestration of 30 to 40 per cent (bottom of Table 6-16).

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

Table 6-16 Overall FN/HRB GHG production (PV of MT)

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>Supply / Load Scenario</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Load Scenario</td>
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<td>81.3</td>
<td>97.9</td>
<td>89.5</td>
<td>91.7</td>
<td>93.5</td>
<td>98.3</td>
<td>216.1</td>
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<tr>
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<td>48.2</td>
<td>60.2</td>
<td>68.0</td>
<td>64.8</td>
<td>66.4</td>
<td>65.8</td>
<td>69.7</td>
<td>153.6</td>
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<tr>
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<td>25.0</td>
<td>30.7</td>
<td>34.3</td>
<td>30.0</td>
<td>34.3</td>
<td>33.7</td>
<td>35.9</td>
<td>77.6</td>
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<tr>
<td><strong>CO₂ Vented (Formation and Combustion) (PV of MT)</strong></td>
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<td></td>
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<td></td>
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<td>54.7</td>
<td>58.6</td>
<td>57.6</td>
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<td>54.5</td>
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<tr>
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<td>55.7</td>
<td>57.8</td>
<td>56.8</td>
<td>57.1</td>
<td>54.6</td>
<td></td>
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<tr>
<td>Low Load Scenario</td>
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<td>60.4</td>
<td>55.8</td>
<td>61.4</td>
<td>55.8</td>
<td>56.6</td>
<td>53.8</td>
<td></td>
</tr>
<tr>
<td><strong>GHG Reduction from No Sequestration (% of PV of MT)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>High Load Scenario</td>
<td>38.0</td>
<td>17.3</td>
<td>0.4</td>
<td>8.9</td>
<td>6.7</td>
<td>4.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Load Scenario</td>
<td>30.8</td>
<td>13.5</td>
<td>2.3</td>
<td>7.0</td>
<td>4.7</td>
<td>5.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low Load Scenario</td>
<td>30.3</td>
<td>14.3</td>
<td>4.4</td>
<td>16.4</td>
<td>4.4</td>
<td>6.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>GHG Reduction from With Sequestration (% of PVS of MT)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2012 Integrated Resource Plan

Page 6-67
BC Hydro’s Share of GHG Emission Production

The CO$_2$ produced and vented from resources owned or acquired by BC Hydro is presented in Table 6-17. With these strategies, a supply strategy based on clean energy from the BC Hydro integrated system results in the lowest GHG emissions, even when considering the BAU strategy.

Co-generation strategies (Columns [3], [4], [6]) generally show higher CO$_2$ for BC Hydro than the CCGT strategy (Column [5]). One observation that needs mentioning is that BC Hydro’s share of GHG production is not necessarily aligned with GHG emissions from the overall system. While co-generation strategies show higher CO$_2$ than the CCGT strategy, much of the increase is because of a transfer of GHG liability from the host processing plant to BC Hydro’s co-generation plant. The co-generation plants are less efficient for electricity production (thus higher CO$_2$ venting) than CCGTs, and make up the efficiency gain by heat sales, which reduce the GHG emissions produced at the host processing plant.

<table>
<thead>
<tr>
<th>Column Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Supply Alternative / Load Scenario</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
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<td>1: BC Hydro System</td>
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<td>20.7</td>
<td>42.6</td>
<td>42.6</td>
<td>31.2</td>
<td>39.5</td>
<td>1.9</td>
<td>1.9</td>
</tr>
<tr>
<td>2A3: Wind &amp; SCGT</td>
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<td>12.4</td>
<td>25.3</td>
<td>28.0</td>
<td>18.5</td>
<td>22.2</td>
<td>1.9</td>
<td>1.9</td>
</tr>
<tr>
<td>2A1(1): One Co-gen Plant</td>
<td>0.4</td>
<td>6.1</td>
<td>13.6</td>
<td>10.8</td>
<td>13.6</td>
<td>10.6</td>
<td>1.9</td>
<td>1.9</td>
</tr>
<tr>
<td>2A1(2): Two Co-gen Plants</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2A2: CCGT</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>2B(1): One Co-gen, New FN SCGT</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>3(1): New FN SCGT</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3(1): No Seq’tn</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Table 6-17 CO$_2$ Produced by BC Hydro Facilities in Fort Nelson/HRB (PV of MT)*
BC Hydro Cost per Tonne of GHG Reduction

A BC Hydro clean electricity strategy as compared to any of the alternative gas-fired generation strategies can be considered as an incremental cost to an incremental reduction in Provincial GHG emission production.

Table 6-18 provides the cost per tonne to take the total BC Hydro cost for each strategy and scenario that includes gas-fired generation, to the equivalent scenario’s system clean strategy (notionally a cost to upgrade each BC Hydro gas generation strategy to clean electricity).

For example, on the first row (High Load Scenario and Market Scenario C), starting from Alternative 2A1(1) (the one co-gen plant, Column [3]), the incremental cost per tonne to take that strategy and convert it to a system clean strategy would be $75/tonne. The cells shaded green indicate strategies and scenarios that would benefit by being converted to system clean strategies, relative to the assumed incremental carbon offset costs for each Market Scenario.

The results show:

- In Market Scenario C, the additional cost for upgrading to a system clean strategy from any of the gas-fired generation strategies is not sufficient to cover that Market Scenario’s expected carbon offset cost; and
- In Market Scenarios B and D, upgrading to system clean energy from the gas-fired generation strategies would be economic in most cases based on that Market Scenario’s expected carbon offset cost.
### Table 6-18
Incremental Cost ($/tonne) to Upgrade Gas-Fired Generation Strategies to a System Clean Energy Strategy

<table>
<thead>
<tr>
<th>Column Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Load Scenario; Market Scenario C; GHG $31/tonne of CO₂</td>
<td></td>
<td></td>
<td>60</td>
<td>75</td>
<td>98</td>
<td>87</td>
<td>99</td>
<td></td>
</tr>
<tr>
<td>High Load Scenario; Market Scenario B; GHG $101/tonne of CO₂</td>
<td></td>
<td></td>
<td>37</td>
<td>57</td>
<td>99</td>
<td>60</td>
<td>91</td>
<td></td>
</tr>
<tr>
<td>High Load Scenario; Market Scenario D; GHG $183/tonne of CO₂</td>
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<td></td>
<td>44</td>
<td>69</td>
<td>125</td>
<td>65</td>
<td>111</td>
<td></td>
</tr>
<tr>
<td>Mid Load Scenario; Market Scenario C; GHG $31/tonne of CO₂</td>
<td></td>
<td></td>
<td>22</td>
<td>65</td>
<td>75</td>
<td>70</td>
<td>96</td>
<td></td>
</tr>
<tr>
<td>Mid Load Scenario; Market Scenario B; GHG $103/tonne of CO₂</td>
<td></td>
<td></td>
<td>7</td>
<td>58</td>
<td>87</td>
<td>48</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Mid Load Scenario; Market Scenario D; GHG $186/tonne of CO₂</td>
<td></td>
<td></td>
<td>19</td>
<td>78</td>
<td>122</td>
<td>56</td>
<td>128</td>
<td></td>
</tr>
<tr>
<td>Low Load Scenario; Market Scenario C; GHG $31/tonne of CO₂</td>
<td>(44)</td>
<td></td>
<td></td>
<td>77</td>
<td>42</td>
<td>76</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low Load Scenario; Market Scenario B; GHG $98/tonne of CO₂</td>
<td>(36)</td>
<td></td>
<td></td>
<td>113</td>
<td>53</td>
<td>93</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low Load Scenario; Market Scenario D; GHG $177/tonne of CO₂</td>
<td>(12)</td>
<td></td>
<td></td>
<td>164</td>
<td>84</td>
<td>129</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
6.6.4.3 93 Per Cent Clean Energy Objective

As noted in section 6.2, BC Hydro has sought to identify the optimal use of gas-fired generation that is available under the 93 per cent clean energy objective. Table 6-19 presents the effect that each of the alternative supply strategies would have on BC Hydro’s ability to meet the 93 per cent clean energy objective.

The analysis results are as follows:

- For the supply strategy based on BC Hydro supplying the region with clean energy from the integrated system (Column [1]), BC Hydro is above the 93 per cent clean energy objective.
- For the supply strategy for Fort Nelson alone (BAU) (Columns [7] – [8]), BC Hydro is above the 93 per cent clean energy objective.
- For the gas-fired generation strategies (Columns [3] – [6]), BC Hydro is below the 93 per cent clean energy objective in the mid and high load scenarios, but above 93 per cent clean energy objective in the low load scenario.
- For Alternative 2A3 (Column [2]), regional clean energy supply with back-up gas-fired resources, BC Hydro is below the 93 per cent clean only in the high load scenarios; the other two scenarios are above 93 per cent.

Given the PV costs of serving a Fort Nelson/HRB low load scenario (approximately $350 million) based on a gas-fired generation strategy are lower relative to a system-based clean energy strategy, BC Hydro may wish to preserve some of its 7 per cent non-clean headroom as an option to support supplying the Fort Nelson load growth and electrification of the HRB.
Table 6-19 Comparison of Alternatives Against 93% Clean Objective (percentage of BC Hydro System Clean Electricity, Average 2020 to 2030)

<table>
<thead>
<tr>
<th>Column</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>With Sequestration</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Load Scenario</td>
<td>95.8</td>
<td>91.4</td>
<td>87.9</td>
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<td>87.9</td>
<td>88.4</td>
<td>95.1</td>
<td>95.1</td>
</tr>
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<td>93.1</td>
<td>91.0</td>
<td>91.0</td>
<td>91.0</td>
<td>91.5</td>
<td>95.1</td>
<td>95.1</td>
</tr>
<tr>
<td>Low Load Scenario</td>
<td>95.6</td>
<td>94.2</td>
<td>93.1</td>
<td>93.1</td>
<td>93.1</td>
<td>93.5</td>
<td>95.1</td>
<td>95.1</td>
</tr>
</tbody>
</table>

6.6.4.4 Supplying Only Fort Nelson

Based on the mid and high load forecasts for Fort Nelson, BC Hydro will need to add new capacity resources in order to maintain N-1 level of reliability. Until a new supply solution is implemented, some Fort Nelson load may be subject to curtailable service. Accordingly, BC Hydro is working with the Alberta Electric System Operator (AESO) to develop a Fort Nelson area load control process and remedial action schemes for events of supply shortfall.
For meeting load up to 73 MW on a firm basis, BC Hydro could construct new gas-fired peaking generation (i.e., SCGT) in Fort Nelson, or contract additional Fort Nelson Demand Transmission Service (FTS) service from Alberta via the AESO. The AESO have indicated that will not offer transmission service beyond 75 MW.

Analysis of the Alternative 3 – Fort Nelson alone strategies provides a comparison between a local SCGT and increased FTS service from the AESO. The following Table 6-20 presents results in a similar format to that in the previous sections. For this analysis only the Fort Nelson mid-load forecast was considered.

<table>
<thead>
<tr>
<th>Table 6-20</th>
<th>BC Hydro’s Total Costs (PV, $ million, without CO₂ Costs)</th>
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</thead>
<tbody>
<tr>
<td><strong>Supply Alternative / Load &amp; Market Scenario</strong></td>
<td><strong>3(1): New Fort Nelson SCGT</strong></td>
</tr>
<tr>
<td>Mid Load Scenario; Market Scenario C</td>
<td>354</td>
</tr>
</tbody>
</table>
In this analysis, selecting an SCGT was always lower cost than increased FTS reliance on Alberta. In both cases, the incremental energy served would be thermal-based, so there is no material difference for clean electricity targets.

If BC Hydro does not undertake a strategy that involved electrifying the Fort Nelson/HRB region, adding peaking capacity or emergency capacity to FNG to meet Fort Nelson load on a firm basis appears to be the lowest cost and preferable strategy.

### 6.6.4.5 Risk Analysis

The economic and GHG analysis presented earlier provide a range of results for differing uncertainties relating to load and market prices.

This section looks at some of the residual risk elements that cannot easily be quantified in that type of analysis. The analysis looks at some of the uncertainties from a perspective of what is at risk if the conditions unfold differently than planned.

A key risk from a long-term planning perspective is the risk of stranded assets.

For example, for the supply strategy based on clean energy from the BC Hydro integrated system, if the Fort Nelson/HRB load that is planned for does not materialize, then the risk consequence would be:

- Low for the clean resources that may have been acquired, as these resources could be redeployed for meeting general integrated system load growth or supply retirements; and

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Mid Load Scenario; Market Scenario B</td>
<td>506</td>
<td>568</td>
</tr>
<tr>
<td>Mid Load Scenario; Market Scenario D</td>
<td>638</td>
<td>699</td>
</tr>
</tbody>
</table>
• High for the NETL transmission, as there would be no alternative use for most of the NETL (the segment between the Peace Region and NPR may provide access to cost-effective clean energy resources to serve system requirements).

Similarly, in the case of supply strategies based on gas co-generation plants, the risk probability lies in the possibility that either the electrical load or the heat load does not materialize or continue at the level expected, in which case the consequences would be:

• Very high for the co-generation plant, which could lose one or both markets; and
• Zero for the NETL transmission from the Peace Region to FNG, because that transmission segment is not required.

A comparison of stranded asset risk across the alternatives is summarized in Table 6-21.
### Table 6-21 BC Hydro Stranded Asset Risk Matrix

<table>
<thead>
<tr>
<th>Supply Strategies / Drivers for Stranded Asset Risk</th>
<th>System Clean</th>
<th>Local Clean / SCGT</th>
<th>CCGT at Fort Nelson</th>
<th>Co-gen at Fort Nelson</th>
<th>Co-gen in HRB</th>
</tr>
</thead>
<tbody>
<tr>
<td>HRB Electrification</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
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<tr>
<td>Host Co-gen Competitiveness</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Electricity Supply (capacity)</td>
<td>Low (redeploy)</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>Very high</td>
</tr>
<tr>
<td>Electricity Supply (energy)</td>
<td>Low (redeploy)</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Very high</td>
</tr>
<tr>
<td>GMS-NPR Transmission</td>
<td>Low (redeploy)</td>
<td>Zero (N/A)</td>
<td>Zero (N/A)</td>
<td>Zero (N/A)</td>
<td>Zero (N/A)</td>
</tr>
<tr>
<td>NPR-FN Transmission</td>
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<td>High</td>
<td>Zero (N/A)</td>
<td>Zero (N/A)</td>
<td>Zero (N/A)</td>
</tr>
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<td>FN-HRB Transmission</td>
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<td>High (equal)</td>
<td>High (equal)</td>
<td>High (equal)</td>
<td>Zero (N/A)</td>
</tr>
<tr>
<td>Sub-transmission</td>
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<td>High (equal)</td>
<td>High (equal)</td>
<td>High (equal)</td>
<td>High (equal)</td>
</tr>
</tbody>
</table>

### 6.6.5 Conclusions

BC Hydro studied two main alternatives for supplying the combined Fort Nelson/HRB loads under mid, high and low electrification load scenarios and under Market Scenarios B, C and D.

In summary, BC Hydro believes a definitive decision on whether or not to electrify the HRB is not required at this time; and that it should continue to work with government, industry and private sector generation proponents in assessing the merits of electrifying the HRB.

Specific findings supporting the summary conclusion are as follows:

- A system clean resource strategy is relatively more expensive than other strategies under Market Scenario C (low market prices). This strategy is at or near the lowest cost under Market Scenarios B and D, when load levels are mid-to-high.

- A system clean strategy can reduce GHG emissions by 30 to 38 per cent relative to industry BAU.
• This option allows for lower cost integration of clean/renewables resources in the North Peace region and loads that would otherwise not be electrified; however the integration benefit does not offset total costs relative to the gas-fired generation alternative.

• Within the gas-fired generation strategies:
  ▶ CCGT strategies are less volatile since they do not rely on heat sales. CCGTs have less market risk than co-generation (more flexible commercial mechanisms, no heat host risk), but miss some of the potential thermal efficiency that might exist from well-balanced cogeneration.
  ▶ Cogeneration appears to be the lowest cost option, but requires a good long-term balance and consistency of heat load and electric load; and require that commercial risks can be adequately addressed; BC Hydro-acquired cogeneration shifts more (most) GHG emissions to BC Hydro.
  ▶ Gas-fired generation strategies can reduce GHG emissions by 0 to 16 per cent relative to industry BAU, but do not meet the 93 per cent clean energy objective other than in a low load scenario.

• A local clean (wind) backed by SCGTs strategy is never the low cost strategy.

Under the scenario where HRB gas producers self-supply their energy requirements, BC Hydro must continue to supply existing and future Fort Nelson load. The two options for serving Fort Nelson load are continued/increased firm service from Alberta and new gas-fired generation at Fort Nelson. The key findings of the analysis are:

• Gas-fired generation operating as reserve and/or peaking capacity is the most cost-effective new supply option for serving Fort Nelson load.

• The alternative of increasing transmission service from Alberta will require significant upgrades in Alberta, the costs to increase to 75 MW (approximately $300 million) would largely be allocated to BC Hydro.
• BC Hydro’s existing transmission service contract of 38.5 MW is based on embedded cost-of-service rates and not likely to face significant rate increases.

• This Fort Nelson-only supply option is not needed if BC Hydro provides electricity service to the HRB via transmission connection to Fort Nelson or transmission connection to the integrated system.

• Until Fort Nelson-only or Fort Nelson/HRB supply is developed and if load in the Fort Nelson region exceeds 38.5 MW, a portion of Fort Nelson customers will not have N-1 service and may be subject to curtailable service until additional generation can be built.

BC Hydro has identified and assessed a number of risks associated with providing electricity supply to Fort Nelson/HRB.

• 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.

• While some proponents in industry continue to express interest in both electrification and CCS as a means of reducing GHG emissions in the HRB, there remains significant uncertainty with respect to industry’s commitment to take electricity service. Clarity on industry’s view may only come through better identification of the opportunities, costs and risks of electrification, and allocation of the costs and risks between the entities.

• Current lower natural gas market prices and production forecasts suggests the expected ramp-up of HRB development has slipped somewhat. This may provide some additional time to identify a workable solution; but must recognize the speed that industry can mobilize, once decisions are made.

• In addition, liability of vented formation CO₂ 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 CO₂, meaningful emissions reductions will require carbon capture and sequestration.

Conclusions in this Fort Nelson section support Recommended Action No. 13 and 14 categorized under “Prepare to for Potentially Greater Demand” as described in section 9.4.4 of Chapter 9.

6.7 General Electrification

6.7.1 Introduction

This section addresses the implications for BC Hydro of a scenario in which government climate policy drives a significant increase in the use of electricity to meet energy end-use demands in place of fossil fuels. Electrification could take place across the economy and across the province, in end-uses such as space and water heating, passenger and freight vehicles, and industrial equipment such as large compressors. The major potential industrial electrification driven loads in the North Coast and Fort Nelson/Horn River Basin have already been discussed separately in previous sections.

The CEA energy objectives include B.C.’s legislated target of reducing GHG emissions by at least 33 per cent below 2007 levels by 2020 and the long-term target of an 80 per cent reduction below 2007 levels by 2050. Achieving these targets will likely involve large scale fuel switching to low- or zero-emissions energy such as low emission or clean electricity. Energy efficiency and switching between high emissions and low emissions intensity fossil fuels (i.e., coal to natural gas) will reduce emissions. However, the deep cuts required to reduce emissions can only be achieved using low- or zero-emissions energy resources (e.g., hydroelectric power, wind, solar, or coal or gas with carbon capture and storage). Yet, none of these resources can be used directly to meet our energy needs such as space and water heating, industrial motor drives, and transportation. Instead they must be transformed into an energy carrier. Currently, the only commercially viable energy carrier is electricity and large reductions in GHG emissions will require switching to
electricity (i.e., “electrification”) as a way to substitute renewable energy for the fossil fuels that power most homes, businesses and vehicles.

Strong climate policies could result in a significant increase in electricity demand and BC Hydro may need to be prepared to respond to such policies by acquiring additional resources to meet higher demand growth. In addition to responding to a possible policy-driven increase in electricity demand, BC Hydro could also take action to support electrification. The CEA provides for regulations to enable utilities to implement programs to support electrification, and specifically references electric vehicles. As these programs would generally result in increased costs to other ratepayers, they would require direction from government.

The key IRP questions on general electrification are:

- What role should BC Hydro play to support provincial climate policy?; and
- What is BC Hydro’s strategy (what and when) to get ready for potential load driven by general electrification? What actions (if any) are prudent in the absence of load certainty?

To address these questions, BC Hydro retained two consultants to study the associated issues and understand the potential for climate policy-driven electrification. In 2010, E3 developed two climate policy scenarios for the WECC region, and estimated the resulting impact on B.C. electricity demand. In 2011, BC Hydro engaged MK Jaccard and Associates to model the impact of climate policy on energy-related GHG emissions in B.C. to provide further information on the end-uses where electricity load could be expected to increase in response to various levels of carbon pricing. At a high level, the findings were that by 2050, electricity demand could be as much as 50 per cent higher than in the business as usual scenario. However, the rate of electrification is limited by capital stock turnover, and even very strong climate policies do not result in significant increases in demand until well past 2020. This suggests that there will be a substantial time lag between
shifts in climate policy and the resulting electrification, enabling BC Hydro to respond
to load growth through the normal planning process.

6.7.2 WECC electrification scenarios

E3 developed two climate policy scenarios with according GHG emission reductions
and evaluated how the response to these scenarios could impact energy
consumption and production across the WECC region. The sector-by-sector GHG
reduction assumptions made by E3 were based on expert qualitative knowledge of
the relative costs of various GHG abatement measures, with conservation-related
savings generally coming first, and major capital stock turnover generally coming
later in the forecast horizon. E3 worked closely with BC Hydro to minimize potential
double-counting of GHG emission savings, as BC Hydro has already included
significant DSM savings in its load forecast, as well as assumptions on oil & gas
industry electrification and the adoption of electric vehicles. The GHG emission
savings estimates and additional electric load were incremental to what was
assumed in BC Hydro’s existing load forecast at the time (2010 Load Forecast) and
any associated GHG emission reductions associated with serving the Fort
Nelson/Horn River Basin and North Coast loads.

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

In the High GHG Reduction scenario, an 80 per cent reduction in GHG emissions is
achieved by 2050, relative to 2008. Of the 80 per cent, 30 per cent can be
accounted for by offsets and the remaining 50 per cent is achieved through
reductions in western states and provinces’ fossil-fuel-based GHGs. B.C. meets the
overall GHG target with 35 per cent of 2050 total emissions savings coming from
offsets.
E3 developed electrification scenarios for WECC and produced the corresponding load scenarios for B.C. BC Hydro then adjusted these load scenarios to load and resource requirements on the BC Hydro system as shown in Figure 6-18. Electrification 2 corresponds to the low GHG reduction scenario and Electrification 3 corresponds to the high GHG reduction scenario.

![Figure 6-18  Electrification Scenarios](image)

A portion of the potential general electrification load is from the transportation sector. The corresponding capacity requirements are significant but it is assumed that there is opportunity to reduce this requirement by half by shifting charging to off-peak hours, for example, by encouraging the installation of a timer which prevents the charging of vehicles during the system peak hours in the evening. Assuming that the charging cycle of the batteries is a few hours, there should be sufficient time to re-charge the batteries over-night (outside of the system peak hours).
In both scenarios, electricity demand does not increase significantly until late in the 2020s. The large savings that occur in the latter part of the forecast horizon are due to major capital stock turnover, such as vehicles, building shells and furnaces (space heating).

6.7.3 Electrification Potential Review

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

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

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

CIMS is the name of an energy-economy simulation model developed and maintained by the Energy and Materials Research Group at Simon Fraser University, B.C., Canada.
6.7.4 Analysis to Identify System Requirements and Potential System Constraints

As illustrated in Figure 6-18, potential general electrification load might grow later and more gradually compared to the potential electrification loads in North Coast and Northeast (Fort Nelson/Horn River Basin) areas. Because of this BC Hydro concluded that there was little value in analyzing the requirements for general electrification on its own as there is little near-term effect on the load-resource balance.

However, for the purposes of stress testing system requirements, BC Hydro created a scenario that looks at the total effects of electrification to understand the system/infrastructure requirements in meeting potential electrification load. A portfolio meeting the combined requirements of load scenarios in the North Coast, Northeast and general electrification was created to stress test system requirements. This scenario sets the upper end of a range of what potential future load requirements could be and is considered to be unlikely. Table 6-22 summarizes the load and supply assumptions for the combined electrification load analysis.

<table>
<thead>
<tr>
<th>Load Assumptions</th>
<th>Supply Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid load forecast</td>
<td>Clean resources from system</td>
</tr>
<tr>
<td>North Coast: Incremental LNG3 scenario</td>
<td>Clean energy backed up by local gas peakers as required</td>
</tr>
<tr>
<td>Northeast: Incremental high gas production and electrification scenario for Fort Nelson/HRB</td>
<td>Clean resources with NETL</td>
</tr>
<tr>
<td>General electrification: Incremental electrification scenario 3</td>
<td>Clean resources from system</td>
</tr>
</tbody>
</table>

For the portfolio analysis for the combined electrification scenario, the following observations were made:

- In general, there are sufficient clean resources in B.C. to meet the combined electrification load scenario described above. The cost of resource options
modelled to meet the combined electrification scenario climb up to the $130/MWh, $160/MWh, $200/MWh range at POI in the 10, 20, 30-year period, respectively.

- The amount of wind that needs to be integrated would exceed the estimated integration limit of 3,000 MW as early as F2020 and 5,000 MW by F2024.
- Even with the addition of Site C, there is further capacity need. Another 4,000 and 12,000 MW of pumped storage are needed by F2031 and F2041 respectively.
- This portfolio also requires significant transmission build out. In this scenario, additional LM/VI cables are needed in the 2030 timeframe, driven by general electrification. Furthermore, multiple lines or HVDC options from the Peace Region to Lower Mainland, and from Prince George to Terrace may also be needed in the late 2020 timeframe and in the 2030s.

### 6.7.5 Conclusions

Economy-wide electrification could contribute significantly to long-term greenhouse gas reductions as part of a climate change strategy to achieve deep cuts in emissions. BC Hydro can support the government’s Climate Action Plan by being prepared to meet the increased load associated with electrification, and by working with government to facilitate electrification through programs enabled by regulation under the CEA. The analysis carried out for this IRP indicates that a move towards general electrification is unlikely to increase load significantly in the next 10 years, and therefore does not require BC Hydro to plan for significant near-term resource additions to meet load growth from electrification. However, there are some preparatory actions that BC Hydro could undertake in support of government climate policy objectives:

- Continue to provide analysis and support to government, such as the electrification potential review carried out for this IRP that identify where electrification would be expected to occur in response to strong climate policy.
• Continue distribution system studies and related activities to ensure that is able to supply the increased loads (e.g., electric vehicles, heat pumps) that could result from significant electrification.

• Continue to investigate the opportunity of managing capacity requirements from electric vehicles such as through the use of timers. In addition, to reflect the findings of the analysis of the combined electrification scenario, there are some preparatory actions that BC Hydro can take to ensure that it is well prepared to meet these incremental and significant electrification loads, should they emerge.

• Advance the exploration of pumped storage as an additional clean energy capacity resource to meet potential future capacity gap.

• Further study the capacity of the BC Hydro system to integrate wind and its limits, should significant new additions of wind power be required to meet the significant combined electrification loads.

These conclusions align with the actions presented on general electrification in section 9.5.1 and support Recommended Action No. 10.

6.8 IPP Acquisition Analysis

6.8.1 Introduction

Earlier sections of this Chapter established that it is cost-effective to fill the load-resource gap through pursuing more DSM energy savings (Option 3) and to continue to pursue Site C. After netting these actions off the load-resource gap, the need for additional resources from IPPs to fill the remaining load-resource gap was analyzed. IPP acquisitions targets are the marginal or ‘swing’ resource. BC Hydro develops actions based on the load/resource balance (LRB) at the time of developing the IRP, but the actual volume targeted by an acquisition process may increase or decrease. In other words, IPP acquisition volumes are subject to both base loads developing as planned, as well as the prospect of incremental load scenarios emerging.
An additional aspect considered for IPP acquisitions was to address the findings of
an energy procurement review undertaken by BC Hydro. In September 2010,
BC Hydro retained Merrimack Energy Group, Inc. to conduct an independent review
of BC Hydro’s power procurement practices to continue to learn from past
experience and "best in class" industry trends. Merrimack undertook a thorough
review that included input from IPPs, other stakeholders and First Nations plus a
comparison with utility practices in other jurisdictions and produced a report with its
findings (“Merrimack Report”). At a high level, the Merrimack report suggested that
the IRP and procurement processes should be linked in terms of the IRP
determining the timing and need for new resources. Merrimack’s report also
highlighted that the IRP was the appropriate vehicle for determining inputs,
assumptions, key acquisition parameters, and considerations underlying an
acquisition process. Examples of these acquisition parameters include market
electricity prices and wind integration costs/limits.

In this section, the IRP key questions are:

- What are the volume and timing of future IPP clean energy acquisitions to
  meet the mid-gap, as well as for contingency conditions and load scenarios?;

- What are the key parameters and their values that will inform future acquisition
  processes? Where possible and meaningful, the sensitivity of these parameters
  on resource mix or costs was tested as part of the IRP portfolio analysis and
  the results are discussed.

There are additional requirements for IPP acquisitions for the capacity load/resource
gap, engaging IPPs in the development of new capacity resource options, such as
pumped storage and natural gas. The need for capacity is discussed in section 6.10.

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26 The report can be found on BC Hydro’s website at:

27 This analysis considered the potential for clean energy only to fill the remaining load-resource gap, as it was concluded in section 6.2 that BC Hydro should preserve the limited amount of natural gas-fired generation available under the 93 per cent clean energy objective for higher value applications.
6.8.2 Acquisition Need: Mid-Gap

The IRP analysis on IPP acquisition volumes uses proxy resources to represent the types of resources that may be bid into a future acquisition process based on the resource options assessment in Chapter 3. As discussed in Chapter 5, the proxy energy resource options considered were limited to wind, run-of-river hydro and biomass, as BC Hydro believes that they are the resources most likely to be part of a future acquisition process. While the actual resources contracted through an IPP acquisition process will vary from the proxy resources selected in the analysis (with respect to resource type, timing, size, cost and location), the proxies are considered indicative of what might happen in future acquisitions at the provincial level and are adequate for planning purposes.

As shown in Figure 6-19, under the mid-gap scenario after targeting DSM Option 3 and advancing Site C to its earliest in-service date, a short-term energy gap remains of up to 3,500 GWh/year between F2017 and F2022. Once Site C comes online, the 5,100 GWh/year of Site C’s average annual energy contribution, as well as other committed or planned resources, meet annual load growth for a number of years. The next time a significant load/resource gap emerges is in 2029.

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28 The IRP analysis assumes that pumped storage developed by IPPs is the proxy capacity resource.
If the short-term energy gap between F2017 and F2022 is filled by long-term contractual arrangements with IPPs, there will be significant surplus energy post Site C until 2029. Given the current market outlook, it is unlikely that the cost of the energy surplus could be fully recovered in the market.

Two bookend portfolios were assembled based on different approaches to fill the short-term energy gap:

- Long-term energy acquisitions: Clean energy is acquired via long-term contracts to fill the short-term energy gap; and
- Market reliance: Market purchases are used to meet the short-term energy gap.
Some of the costs and benefits of these different approaches are:

- The cost of the market reliance approach is approximately $900 million (present value) less than the long-term energy acquisitions approach over the planning period and results in about a 7 per cent rate savings in F2022 (assuming mid-gap and Market Scenario C).\(^{29}\)

- The market reliance approach meets the self-sufficiency requirement over the long term, but it would not meet it in the short term.

- The market reliance approach contemplates further planned market reliance over and above that resulting from planning to meet self-sufficiency based on average water conditions. BC Hydro conducted additional analysis on this question and considered whether it could accommodate additional reliance on domestic non-firm energy or the market and still reliably serve customers, in addition to the planned maximum 4,100 GWh/year of market exposure from average water conditions. The analysis looked at the effects of water variability, market conditions, market access, operational constraints and additional planning uncertainties. BC Hydro concluded that it could rely upon markets for 4,500 to 6,500 GWh/year of energy. Based on the results of this analysis, BC Hydro believes that an additional 2,400 GWh/year of planned non-firm energy/market allowance for the short term would still result in a reliable system (i.e., effectively taking the upper bound of non-firm energy/market reliance to 6,500 GWh/year. with non-firm energy/market reliance may not meet reliability requirements.

- The 7 per cent rate savings does not last indefinitely; rates would converge again in the late F3030s, as self-sufficiency was achieved.

- BC Hydro looked at the costs of long-term energy acquisitions of 2,000 GWh/year, relative to the costs of the long-term energy acquisitions portfolio. Moving from full long-term energy acquisitions to 2,000 GWh/year of

\(^{29}\) The results of this analysis are provided in Appendix 6A.
long-term energy acquisitions results in a decrease in costs of $350 million (PV) and 3 per cent rate impact. This would require an additional approximate 1,500 GWh/year of market reliance to meet the short-term gap, which BC Hydro believes it can accommodate and still meet customer’s needs reliably. This approach would not meet self-sufficiency requirements for a two to three-year period.

- This analysis assumes a mid-gap scenario with Initial LNG development. If Initial LNG does not develop as planned, the short-term energy gap may decrease or be entirely eliminated. Therefore, long-term energy acquisitions made in advance of the Initial LNG investment decisions may bear the risk that they aren’t required.

Based on the results of the analysis and considerations listed above, the following conclusions can be made:

- Filling the short-term energy gap solely with either long-term energy acquisitions approach or market reliance approach has undesirable consequences. Using long-term energy acquisitions to fill a short-term gap results in a significantly higher present value cost than relying on the market. Conversely, BC Hydro may not be able to reliably meet customers’ needs by relying on the market entirely for an additional 3,500 GWh/year over the short term. Therefore, a strategy that balances these two approaches to fill the short-term gap is desirable.

- A balanced approach of relying on an additional 1,500 GWh/year form the markets and acquiring the remaining approximately 2,000 GWh/year of energy through IPP acquisitions reduces costs and rates and is a balanced approach to meeting self-sufficiency that meets reliability considerations.

- BC Hydro should monitor the development of the LNG facilities to time future acquisitions to the final investment decisions for those facilities and mitigate the risk to ratepayers that the acquisitions are not required.
6.8.3 Acquisition Need: Energy Contingency and Incremental Load Scenarios

As discussed further in section 6.10 for capacity resources, there are a number of uncertainties and risks that BC Hydro considers in its resource planning and analysis. If an uncertainty leads to the risk that customer requirements will not be served, BC Hydro needs to develop plans to manage these risks.

From an energy perspective, the main planning uncertainties are classified as incremental load scenarios and contingency events. The discussion in sections 6.5, 6.6 and 6.7 highlights significant potential incremental load that may emerge in the North Coast and Northeast regions as well as the overall system due to general electrification. There may also be contingency events, such as loads being higher than forecast or DSM savings being less than planned. As mentioned in the introduction to this section, IPP acquisitions are the marginal resource that BC Hydro considers to meet these incremental loads. While IPP resources would not likely be available in time to meet short-term contingency events, they play a role in managing longer-term load-resource balance gaps.

The factors that BC Hydro considers in managing energy planning uncertainty include:

- Timing (does the event occur in the near-term or long-term?);
- Reaction time (can BC Hydro develop alternative plans to respond to the contingency event, or must it rely on existing solutions, such as the market?);
- Definition of the event (does the event develop as a trend over time, or does it occur with a signpost that it is emerging?).

The planning uncertainties are categorized in Table 6-23 according to these factors.
To address near-term contingency conditions arising from uncertainties around normal load growth and DSM savings, BC Hydro relies on market energy. The key reasons for relying on the market are: there is insufficient reaction time to develop alternative resources; building in advance need is prohibitively expensive; and market reliance is both cost-effective and reliable. If a larger course correction is required to the load forecast or DSM savings estimates, this can be addressed through load-resource balance adjustments in an updated IRP.

Other contingency conditions for which there are warning signs that additional energy is required include the development of Site C being materially delayed. These contingencies generally provide sufficient time for BC Hydro to react and adjust planning actions.

BC Hydro plans to meet the incremental load scenarios in a different manner than contingency events, because there is generally sufficient reaction time, coupled with a signpost that the event is going to occur. As such, BC Hydro advances additional

<table>
<thead>
<tr>
<th>Category</th>
<th>Uncertainty</th>
<th>Potential Impact</th>
<th>Leading Indicator</th>
<th>Number of Years of Advance Warning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Near-Term, Possible Insufficient Reaction Time, Gradual</td>
<td>Load</td>
<td>+/- 3,000 GWh/year in F2017</td>
<td>Year-by-year load growth</td>
<td>1-4</td>
</tr>
<tr>
<td>DSM</td>
<td>+ 2,100/-2,400 GWh/year in F2017</td>
<td>Year-by-year load growth</td>
<td>1-4</td>
<td></td>
</tr>
<tr>
<td>Near-Term, Sufficient Reaction Time, Signpost</td>
<td>LNG 3 &amp; High Future Mining</td>
<td>+ 11,600 GWh/year in F2021</td>
<td>Customer requests</td>
<td>3-4</td>
</tr>
<tr>
<td>High Fort Nelson/HRB</td>
<td>3,900 GWh/year in F2021</td>
<td>NETL commitment</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Long-Term, Sufficient Reaction Time, Signpost</td>
<td>Site C</td>
<td>Material delay more than 5,100 GWh/year average energy</td>
<td>Approvals to proceed; In-service date</td>
<td>4</td>
</tr>
<tr>
<td>Long-Term, Sufficient Reaction Time, Gradual</td>
<td>General Electrification</td>
<td>+1,362 GWh/year in F2021</td>
<td>Gov’t policy, load growth, technology</td>
<td>3-6</td>
</tr>
</tbody>
</table>
IPP acquisitions to meet the requirements of the incremental load scenarios, but needs to confirm the timing of these loads prior to awarding EPAs.

As discussed in sections 6.6 and 6.7, the incremental energy needs associated with Fort Nelson/Horn River Basin and general electrification will depend on government policy and industry needs and preferences. The incremental loads identified in these scenarios do not yet warrant advancing acquisition activities. However, as discussed in section 6.5, the potential LNG3 load in the North Coast does warrant starting the planning and design of acquisitions in F2013 before the load requirement can be confirmed. To that end, BC Hydro should plan for an acquisition process, targeting in the order of 10,000 GWh/year. Work needs to commence now to ensure that projects could come on-line by the end of the decade if necessary. A final commitment to acquire this energy will coincide with load commitment. Chapter 9 provides more information on how BC Hydro will mitigate the cost risks associated with planning to meet uncertain incremental loads.

6.8.4 Key Acquisition Parameters and Considerations

This section describes the key parameters and considerations for future acquisition processes and presents the results of IRP analysis where the sensitivity of these parameters on resource mix or costs was tested. The results of this analysis inform both the resources targeted and the evaluation framework of future acquisition processes.

These parameters and considerations include:

- Procurement options;
- Market electricity prices;
- RECs;
- Wind integration costs;
- Wind integration limits;
- Freshet energy oversupply;
- Locational adjustments;
- Capacity value;
- Firm energy;
- Regional issues;
- Qualitative factors; and
- Other resources.

6.8.4.1 **Procurement Options**

The Merrimack Report recommended that BC Hydro continue to follow its recent trend of combining or mixing procurement vehicles to match the solicitation, for example:

- Utilizing a more flexible Request for Proposals (RFP) process for larger and broader (province-wide) solicitations;
- Implementing other procurement vehicles such as Call for Tenders (CFT), Requests for Offers, or Feed-in Tariffs for smaller or targeted resources.

For the IPP acquisition processes identified in the Chapter 9 Action Plan, BC Hydro will review a range of procurement options, particularly the flexible RFP approach for larger acquisition processes and other vehicles such as standard offers and bilateral negotiations for targeted procurements.

6.8.4.2 **Market Electricity Prices**

Market electricity prices are an important parameter in energy acquisition evaluation because they reflect the value of non-firm energy, surplus energy and IPP opportunity costs. As discussed in Chapter 4, BC Hydro’s most current view of long-term electricity prices is a forecast from Ventyx, the vendor of BC Hydro’s price forecast model.

[Figure 6-20](#) shows the most current long-term Mid-C price forecast from Ventyx, compared to Market Scenario C. On a levelized basis, the two forecasts are almost
equal; Market Scenario C’s 20-year levelized price is $38/MWh compared to Ventyx at $39/MWh. The Ventyx forecast is lower than Market Scenario C prices in the near-term implying an extended recovery from the economic recession and higher in the post-2020 period, suggesting a longer-term recovery.

**Figure 6-20** IRP Market Scenario C vs. Ventyx Price Forecast

BC Hydro is of the view that the Ventyx electricity price forecast represents a more current and realistic view of electricity market prices that account for price/market transitions from one scenario to another. For this reason, BC Hydro is adopting the Ventyx price forecast as its interim official price forecast for evaluating market energy for energy acquisition processes. BC Hydro updates its electricity price forecasts on an annual basis and will incorporate new outlooks on long-term electricity prices in future updates.

In addition to annual prices, BC Hydro has valued energy according to different time periods when it is delivered within a given year. Time-of-delivery factors (i.e., a “3 x 12” table showing different values for each month and different daily demand
levels have been applied across acquisition processes. Given the trend in recent years of depressed prices during freshet and continued high demand in the winter, BC Hydro should continue to recognize different energy values for different time periods in acquisition processes and update its official within-the-year price profile, including the time of delivery factors for current market conditions.

6.8.4.3 Renewable Energy Credits

As BC Hydro undertakes the acquisition of clean energy resources, there are clean energy attributes that may change the value of particular resources. This section addresses the key considerations of these clean energy attributes as they relate to portfolio modelling in long-term plans and how they may be approached in future acquisition processes.

As discussed in Chapter 4, energy from renewable resources that are eligible under the Renewable Portfolio Standards (RPS) set by various U.S. states can receive revenues in addition to the energy values, through the sale of the associated Renewable Energy Credits or Certificates (REC). RECs are more valuable when sold with the underlying energy product, but RECs traded separate from the energy have also earned some value in the past.

Given RECs and energy can be sold separately, this raises the question as to whether BC Hydro should sell the underlying RECs and recognize the value in its portfolio assessments. The following points are considered:

- Power without the associated RECs is considered “null” electricity since it no longer has any associated environmental benefits.

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30 RECs represent the environmental/clean energy attributes associated with renewable electricity that can be unbundled from the physical electricity and sold as a separate product. RECs, environmental attributes and clean energy attributes are used interchangeably here, although the term environmental attributes typically refers to a contractual product and RECs are a commodity traded in existing markets.

31 See, for example, the Western Climate Initiative’s position set out in “Electricity Subcommittee Discussion Paper on Renewable Portfolio Standards, Renewable Energy Credits and GHG Accounting” (December 2008), page 1.
There is a potential GHG liability associated with null electricity because it has no specific GHG characteristic and may be allocated some GHG intensity, whereas clean electricity has no or very low GHG intensity.

In order to mitigate future GHG liability risks, BC Hydro has concluded that it would plan to retain all RECs unless the energy was surplus to its needs. In its portfolio analysis, BC Hydro has modelled that energy surplus to its needs would be sold with available RECs. As discussed in section 4.5.5, the values assumed for the REC value was estimated at $4/MWh. This is consistent with the increasing constraints occurring in RPS markets and the short term nature of BC Hydro energy surpluses planning to average water conditions.

BC Hydro next considered whether RPS-eligible resources are preferred since not all renewable resources have the same ability to generate REC revenues. Of the resource options with which BC Hydro has or is likely to have EPAs, wind and biomass meet many U.S. state RPS requirements. Run-of-river hydro projects, although clean and renewable, are typically subject to much greater eligibility requirements (or are excluded).

The IRP analyzed how the Market Scenarios (including REC Price Forecasts) could influence the preference for resources in future acquisition processes. REC Price Forecasts (capped at $4/MWh) are used in the IRP analysis to estimate incremental revenue that would result from the sale of the clean or renewable electricity that is surplus to BC Hydro’s system need and is RPS-eligible energy. Wind and biomass are modelled as RPS-eligible resources. Figure 6-21 shows the resource mixes selected by System Optimizer for a portfolio meeting the mid-gap across the five Market Scenarios. To contrast the influence on resource mix, these portfolios were created without Site C to maximize the volume needed.

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As BC Hydro is now planning to average water conditions, it will have adequate energy in its system on average to meet customer requirements. Practically speaking, it will have surplus energy in about half of the years and a shortfall in the other years, so that any energy surpluses will necessarily result in short term sales.
In all Market Scenarios, the resource mix is quite balanced between run-of-river hydro, wind and biomass. There is a slight preference for wind and biomass in Scenarios B, C and E (where there are mid-to-low electricity prices and REC prices are about $4/MWh) compared to Scenarios A and D (where electricity prices are high and REC prices are $0/MWh or very low). In Scenarios B, C and E, the higher REC prices did not drive clear preference for wind and biomass even when lower electricity prices already put run-of-river hydro at a disadvantage because its non-firm energy is sold at a loss.

Finally, BC Hydro considered whether additional value for RPS-eligible resources should be recognized in acquisition processes. The following observations are made:

- As discussed in Chapters 4 and 7, REC markets continue to evolve, including rules defining RPS-eligibility. California is the largest market, but market size for out-of-state resources is limited and continues to shrink. While there exist some
limited opportunities in the near-term for higher value REC trades, in BC Hydro’s view, the market value of RECs for B.C. resources is currently estimated at $4/MWh.

- Given potential GHG liability as discussed earlier in this section, BC Hydro’s long-term view is that it may only earn revenue from REC sales if its system has surplus energy. Under the average water planning criteria, BC Hydro system will have surplus energy in some years and deficit in others. This means REC revenue is only available to BC Hydro opportunistically, is uncertain and for short term, further limiting the value of REC sales to BC Hydro.

- BC Hydro has already acquired a reasonable amount of renewable resources that are REC compliant that could be used to support surplus renewable energy sales including REC values.

While RPS-eligible energy has additional market value, its value to BC Hydro is limited, potentially only short-term in nature, and only available on an opportunistic basis. To the extent that acquisition processes differentiate RPS-eligible resources, the value will be minimal to avoid unnecessary REC price risk.

6.8.4.4 Wind Integration Costs

Due to natural variations in wind speed, wind power generation is highly variable in the short-term timescales of seconds to minutes, resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. The natural variability in wind power generation also makes it difficult to forecast wind in the hour- to day-ahead timeframe, resulting in the need to set aside system flexibility to address the potential for wind generation to either under- or over-generate in this time frame. Both of these requirements for system reserves and flexibility have cost implications that are specific to wind power
generation\textsuperscript{33}, and hence are captured through a wind integration cost adjustment that has been used in the IRP analysis and also previous acquisition processes.

BC Hydro first started to investigate wind integration costs in 2008, where a wind integration cost of $10/MWh was applied in the 2008 LTAP portfolio analysis, as well as in the subsequent Clean Power Call evaluation. Since 2008, BC Hydro has conducted a more detailed, second-phase wind integration study, which is provided in Appendix 6E.

The BC Hydro Wind Integration Study Phase II considers 12 wind integration scenarios, consisting of:

- Two study years, F2011 and F2021, which represent different load and system generation configurations.
- Two wind diversity levels: Economic Dispatch and High Diversity. For the Economic Dispatch case, wind farms are ranked and chosen according to their estimated cost. As the lowest cost wind resources generally come from the Peace River region, this case also represents low wind diversification. In the High Diversity case, wind farms are chosen equally from all regions in B.C.
- Three wind penetration levels: 15 per cent, 25 per cent, and 35 per cent. The wind penetration level is defined as the percentage of installed wind capacity to peak load.

The wind integration costs for the twelve scenarios are shown in Table 6-24.

Generally speaking, the wind integration cost increases as the wind penetration level increases\textsuperscript{34}, whereas geographic diversification significantly reduces the wind integration cost.

\textsuperscript{33} Other renewable resources, such as solar and wave, are also highly variable in the short-term timescales. However, because they are not expected to participate or be selected in future acquisition processes in a significant manner, their integration costs have not been specifically estimated. The variability of run-of-river generation is largely contained within the monthly/seasonal timeframe, which is captured in the IRP modelling tools.

\textsuperscript{34} It should be noted that the lower wind integration cost for the Economic Dispatch, 35 per cent scenario relative to the Economic Dispatch, 25 per cent scenario is due to higher geographic diversification in the 35 per cent case relative to the 25 per cent case.
integration cost for all study years and all penetration levels. The wind integration costs range from $5/MWh to $19/MWh, with a wind integration cost of approximately $10/MWh corresponding to the F2011 Economic Dispatch – 15 per cent scenario. This value will be updated over time with further study on wind integration costs. Given that $10/MWh is within the range, BC Hydro will continue to this figure for wind integration costs in the IRP analysis and future acquisition processes.

<table>
<thead>
<tr>
<th>Total Wind Integration Cost ($/MWh)</th>
<th>F2011 Study Year</th>
<th>F2021 Study Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic Dispatch – 15% (1,500 MW)</td>
<td>10.79</td>
<td>12.79</td>
</tr>
<tr>
<td>High Diversity – 15% (1,500 MW)</td>
<td>5.39</td>
<td>6.04</td>
</tr>
<tr>
<td>Economic Dispatch – 25% (2,500 MW)</td>
<td>15.58</td>
<td>19.41</td>
</tr>
<tr>
<td>High Diversity – 25% (2,500 MW)</td>
<td>6.36</td>
<td>7.31</td>
</tr>
<tr>
<td>Economic Dispatch – 35% (3,500 MW)</td>
<td>13.57</td>
<td>16.57</td>
</tr>
<tr>
<td>High Diversity – 35% (3,500 MW)</td>
<td>7.64</td>
<td>8.51</td>
</tr>
</tbody>
</table>

To test the sensitivity of the portfolio results to the wind integration cost, additional model runs were conducted using $5/MWh and $15/MWh, which represent a reasonable range of the low and high values of the wind integration costs. Figure 6-22 shows that the wind integration cost impacts resource selection to some degree, with the lower wind integration cost showing preference towards more wind power generation. However, the range of wind integration costs tested does not result in all-wind or no-wind portfolios.

35 Based on the following model parameters: Mid-gap size, market scenario C, DSM Option 2, North Coast load based on KM LNG only, Site C in EISD, no additional thermal generation, and modelling horizon of 20 years.
Figure 6-22 shows that the wind integration costs for scenarios with high geographic diversification are $5/MWh to $12/MWh less than those for the corresponding economic dispatch scenarios for which the majority of projects are located in the Peace River region. However, as the analysis in Chapter 3 on the costs of wind energy shows, the cost of acquiring wind projects to achieve diversity (i.e., outside the Peace River region) may be in excess of $20/MWh. Therefore, the economic benefits of geographic diversification are outweighed by the cost of acquiring diversified wind projects. This suggests that it is not worthwhile to conduct region-specific acquisitions for power for the specific objective of improving wind diversity, but there may be opportunity to capture diversity benefits during future acquisition processes.

Or said another way, the wind resource option assessment found that the costs of developing wind projects in the Peace River region were generally >$20/MWh less than in other areas.
Finally, BC Hydro also conducted a review of wind integration costs found in recent studies from other jurisdictions. The findings from this review are provided in Table 6-25.

<table>
<thead>
<tr>
<th>Utility/Study</th>
<th>Timeframe</th>
<th>Findings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Puget Sound Energy Within-Hour Load Following OATT Tariff effective June 2010</td>
<td>Within-Hour</td>
<td>$2.70 kW-month @ 30% CF = $12.33/MWh</td>
</tr>
<tr>
<td>PacifiCorp 2008 Wind Integration Study</td>
<td>Within-Hour</td>
<td>$7.51/MWh @ $8 CO2 cost $9.40/MWh @ $45 CO2 cost</td>
</tr>
<tr>
<td></td>
<td>Hour-Ahead</td>
<td>$2.17/MWh</td>
</tr>
<tr>
<td></td>
<td>Day-Ahead</td>
<td>$0.28/MWh</td>
</tr>
<tr>
<td></td>
<td>TOTAL</td>
<td>$9.95/MWh @ $8 CO2 cost $11.85/MWh @ $45 CO2 cost</td>
</tr>
<tr>
<td>Bonneville Power Administration 2010 Rates</td>
<td>Within Hour</td>
<td>Regulating Reserves $0.05/kW/mo Following Reserves $0.26/kW/mo Imbalance Reserves $0.98/kW/mo Total $1.29/kW/mo @ 30% CF = $5.89/MWh + Wind generators are subject to a persistence deviation penalty to address ramping forecast inaccuracies.</td>
</tr>
</tbody>
</table>

While exact comparisons between studies cannot be drawn because of differences in cost component assumptions and study parameters, at a high level, a wind integration cost of $10/MWh seems to be within the range of other jurisdictions.

6.8.4.5 Wind Integration Limit

A preliminary analysis has been completed to determine the maximum amount of wind power that can be integrated into the current BC Hydro power system without impacting the reliability and security of the system. The analysis is based on the assumption that only dispatchable generation from automatic generation control (AGC) plants can be used to manage wind variability and ramps.
The analysis is based on actual hourly system operation data, including load, generation, max/min generation limits, outages and tie line schedules, for the period October 2007 to September 2008. Actual wind data is not used in this analysis, but instead the assumption is made that the intra-hour wind power fluctuations may range from minimum to maximum output (worst case scenario) and that the dispatchable resources have to be able to respond to these fluctuations.

The analysis shows that the system is most constrained during the freshet period, when the available dispatchable AGC generation drops to approximately 3,000 MW. Hence, 3,000 MW has been adopted as the current wind integration limit. This preliminary analysis does not consider transmission constraints, market constraints for the surplus wind energy, or trade-offs with spilling and/or wind curtailment. Since the analysis is based on historical data, it also does not include a build-out of the BC Hydro system, which would include Mica Units 5 and 6, Revelstoke Units 5 and 6, and Site C. With these additional generation facilities, it is assumed that the wind integration limit may increase to 5,000 MW, although further studies are required to confirm this.

Figure 6-23 shows that under the mid-gap scenario, the modelled installed wind capacity stays well below the currently estimated wind integration limit of 3,000 MW for the next 20 years. Under the large-gap scenario, however, the modelled installed wind capacity approaches the wind integration limit, Figure 6-23, in 2019, and hence could become a near-term issue. Other load scenarios requiring additional wind resources would also impinge on the wind integration limit as early as 2019. BC Hydro should continue to refine the understanding of its wind integration limit and explore resources and methods (e.g., spilling/curtailment) that can enhance integration capability.

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37 Some of these factors may reduce integration capability whereas some are managing options for consideration that may help increase the capability.
Figure 6-23  Modelled Installed Wind Capacity under the Mid-gap, DSM Option 2, With Site C Scenario

Figure 6-24  Modelled Installed Wind Capacity under the Large-Gap, DSM Option 2, With Site C Scenario
6.8.4.6 *Freshet Energy Oversupply*

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

BC Hydro’s oversupply period has a significant overlap with the oversupply period in the US Pacific Northwest. The Pacific Northwest also has significant large hydro resources and a freshet period (mid-April to mid-July), when the region has an oversupply of energy because of run-off and relatively low demand. This leads to low electricity market prices in the spring. In recent years, additions of significant volumes of non-dispatchable wind generation in the Pacific Northwest region\(^{38}\) have contributed additional energy in the same spring freshet period. This additional wind energy has the impact of further reducing electricity market prices in this period, at times driving them negative\(^{39}\).

BC Hydro utilizes the storage capability and dispatch flexibility of its Heritage hydro system to store most of the energy for later use and minimize exports during the freshet period. However, this flexibility is limited and after that, BC Hydro is forced to sell energy into the market during freshet or spill the water/energy because of an oversupply that cannot be stored\(^{40}\). There is also a lost opportunity that results from having increased resources delivering in the freshet. Under conditions when BC Hydro is not forced to sell during the freshet, increases in freshet generation (e.g., from non-dispatchable resources and resources with minimum flow

\(^{38}\) There are over 4,000 MW of wind generation in BPA balancing area, more elsewhere, and with more to come.

\(^{39}\) Wind producers in the Pacific Northwest region can earn production tax credits if they generate energy, making it economic for them to sell even at negative prices. Fish constraints at US hydro projects prevent them from backing down generation and spilling.

\(^{40}\) Note that such forced sales can occur even when the large Peace and Columbia storage project releases are at a minimum.
requirements) erode BC Hydro’s ability to purchase very low-priced market energy to serve our customers’ load while saving water/energy for sale later in higher price period. This has a negative financial impact on BC Hydro.

In order to avoid further negative impacts of surplus energy in the freshet, BC Hydro must take into consideration the impact of freshet period energy deliveries in its resource acquisition. The following are potential mitigation measures to the freshet oversupply/low market price concerns:

(i) Reduce purchases of non-dispatchable energy during freshet periods;

(ii) Link purchase prices of any additional energy during freshet periods to actual market prices and market availability;

(iii) Include more dispatchable generation resources in BC Hydro’s supply portfolio;

and

(iv) Increase loads during freshet periods.

An example of the fourth mitigation measure is the additional load requirement for LNG, which is relatively constant over the year, would help flatten BC Hydro’s load profile and could help mitigate the freshet energy oversupply issue to some degree. However, practically speaking, it is difficult for BC Hydro to modify seasonal load requirements/shapes to benefit resource management.

An analysis looking at forecasted monthly minimum generation to meet load for study year 2016 was undertaken to understand the extent of the freshet oversupply issue given load from initial LNG. This analysis considers a range of inflow conditions while simulating/optimizing the operation of system resources. Figure 6-25 shows that the minimum generation in the BC Hydro system is at its highest from June to August when customer demand is relatively low, resulting in an energy surplus under many inflow conditions.
6.8.4.7  **Locational Adjustments to Load Centres**

Most of BC Hydro’s recent acquisition processes have included locational adjustments for projects (e.g., losses, transmission costs) to account for the costs of delivering energy to load centres. As these costs can be significant, locational adjustments should continue to be used as part of the acquisition evaluation framework.

While the major load centre in B.C. has historically been the Lower Mainland, future acquisition processes will need to also recognize significant regional load growth, such as in the North Coast, should new incremental LNG loads emerge. The load associated with Initial LNG alone, on B.C.’s North Coast, accounts for about 26 per cent of incremental load growth between F2012 and F2021.
6.8.4.8 Capacity Value

While the primary focus of this section is on energy acquisition, energy resources may also have some associated dependable capacity. Some of BC Hydro’s recent acquisition processes have provided an hourly firm energy credit as part of the evaluation framework to reflect the value of this associated capacity to BC Hydro.

The value and need for capacity is discussed further in section 6.10 and establishes that capacity needs are significant over the short-term and long-term. This section also discusses how traditional capacity resources are being exhausted (e.g., Resource Smart projects such as Revelstoke Unit 6) and how BC Hydro has to look at options such as natural gas and pumped storage to meet future capacity needs.

As future capacity needs are a key issue for BC Hydro, future acquisition processes should continue to value the dependable capacity provided by energy resources on an individual project basis (not on a portfolio basis). The value of this dependable capacity should be based on the marginal capacity resource which, following the commitment to build Revelstoke Unit 6, will become natural gas (subject to future development work confirming the viability of pumped storage).

6.8.4.9 Firm Energy

BC Hydro’s planning criteria requires that annual firm energy be acquired to fill its load-resource gap. However, the Merrimack Report highlighted certain terms in BC Hydro’s standard EPA included to acquire seasonally and contractually firm energy, which would merit additional analysis to better understand the trade-off, if any, between risk and cost to BC Hydro. To that end, the specific terms identified by Merrimack for review are:

- Five-year ratchet provision adjusting firm energy delivery levels down to levels exceeded by 80 per cent of the performance periods;
- Financial penalties for under-delivery from the first MWh; and
- Pricing intermittent resources on the basis of strict seasonal delivery requirements.
Assessment of these contract provisions is currently underway and appropriate changes will be made depending on the outcome of the study. It should be noted that certain contract and evaluation features in the acquisition process are meant to incent, price and differentiate between projects that provide the best value to BC Hydro’s system. As a result appropriate deviations between system/portfolio wide IRP analysis and acquisition framework which tends to be more project specific, may exist. Overtime, BC Hydro will assess the impact of these deviations and update the future IRP analysis and acquisition designs accordingly.

6.8.4.10 Regional Issues

A number of areas in the IRP analysis address whether there is benefit to initiating a regional acquisition process. This topic is discussed in section 6.8.4.4, which looked at whether there was benefit to implementing regional acquisitions to improve wind diversity with the objective of lowering wind integration costs. The finding was that there is no apparent financial benefit to a regional acquisition process; however, there may be opportunity to look at increasing diversity within acquisition processes. This question is also explored in the analysis of generation clusters in section 6.9.4, which examines the benefits of pre-building transmission to a geographic area to access a high density of generation resources. The analysis concluded that there are marginal benefits with pre-building transmission, but that there are also significant risks with the approach. BC Hydro can continue to look for opportunities for clustering to be considered within future acquisition processes.

BC Hydro also continues to evaluate the requirements for the incremental load scenarios, and particularly LNG3. As discussed in section 6.5, BC Hydro is looking at two supply options, which include the bookends of regional clean generation backstopped by natural gas SCGTs and province-wide clean energy generation supported by transmission. BC Hydro is recommending further study on the supply options, including a hybrid option. Because this analysis is ongoing, no decision has been made on the nature of the acquisition process.
6.8.4.11 Qualitative Evaluation Factors

Qualitative evaluation or non-price factors can be used within an acquisition process to reflect additional attributes of value that do not have market value or are not easily quantified. Qualitative evaluation factors could be used to reflect a wide range of considerations that BC Hydro may want to weight or rank projects on in the acquisition evaluation process, such as project readiness or viability.

The Merrimack Report considered the issue of qualitative evaluation factors. Their recommendation for a best practice in this area was to develop transparent weightings for non-price factors to evaluate bids.

As identification of qualitative evaluation factors would be part of the acquisition process development and specific to the product(s) being acquired, BC Hydro does not see a need to specify qualitative evaluation factors for future acquisition processes at this time. However, a qualitative evaluation factor could be, for example, relative economic benefits for First Nations/remote communities, consistent with CEA objective 2(l). If BC Hydro utilizes qualitative evaluation factors within a future acquisition process, it will apply the finding of the Merrimack Report and endeavour to develop transparent weightings.

6.8.4.12 Other Resources

As discussed earlier in this section, the IPP acquisition analysis used proxy resources of wind, run-of-river hydro and biomass to represent the types of resources that BC Hydro believed most likely to be procured in a future acquisition process. To understand whether other resources are likely to participate in future acquisition processes, additional work may be required. Of particular note, geothermal continues to show that it may be a cost-effective source of clean energy with considerable dependable capacity, a key IRP issue. However, the exploration and testing of sites to prove out the heat and energy potential for geothermal is both high in costs and risk. BC Hydro should continue to work with the Provincial Government to assess the feasibility of developing geothermal.
6.8.5 Conclusions

Conclusions on the volume, timing and approach to future energy acquisitions are as follows:

- After DSM Option 3 and Site C’s energy contributions are accounted for, a short-term load-resource gap of up to 3,500 GWh/year from F2017 to F2022 emerges. BC Hydro believes that a strategy that balances acquisitions with market reliance is appropriate and recommends an IPP clean energy acquisition process to target 2,000 GWh/year. While this approach does not meet self-sufficiency requirements in the short-term, BC Hydro believes this balanced approach is prudent to minimize costs and rate impacts.

- To be in a position to serve potential third LNG facilities, BC Hydro should start preparations for an additional clean energy acquisition process for approximately 10,000 GWh/year of clean energy in either the North Coast region or in the province. Chapter 9 provides more details on the actions BC Hydro plans to take to prepare to meet this emerging load, including mitigating the risk that these loads do not develop as planned.

Several key parameters/considerations that were addressed in the IRP should be incorporated in the acquisition processes for clean energy resource acquisition:

- BC Hydro will continue to reflect the market price of electricity in its acquisition evaluation process and adopts a Ventyx electricity price forecast as its interim official price forecast. BC Hydro should update the within-the-year price profile and recognize value for different time in the year.

- The market value of RECs for B.C. resources is estimated at $4/MWh. While RPS-eligible energy has additional market value, its value to BC Hydro is limited, potentially short-term in nature, and only available on an opportunistic basis. Acquisition processes should limit the value attributed to RPS compliance to avoid unnecessary REC price risk.
The wind integration cost is being maintained at $10/MWh as this value is still considered reflective of wind integration costs, given a range of wind penetration levels and diversity assumptions considered.

The preliminary wind integration limit is estimated at about 3,000 MW and may increase with additional generation facilities. This limit is not expected to be a near-term constraint, but, if contingency conditions or additional load scenarios considered in this IRP materialize, it could be impinged as early as F2020.

BC Hydro should continue to refine the understanding of its wind integration limit and explore resources (e.g., Mica pumped storage) and methods (e.g., spilling/curtailment) that can enhance integration capability.

High freshet generation (e.g., from non-dispatchable resources and resources with minimum flow requirements) of the BC Hydro system has resulted in significant and increasing lost opportunity costs which have a negative financial impact on BC Hydro, and which have culminated recently in spills to avoid selling into negatively-priced markets. This erosion of flexibility is exacerbated under high annual inflow conditions, but exists even in low inflow sequences.

BC Hydro must continue to address the freshet oversupply conditions in future acquisition processes by limiting energy acquiring in the freshet, linking energy prices to market in the freshet period, adding dispatchable generation, and increasing freshet loads.

BC Hydro should continue to apply locational adjustments in future acquisition processes to reflect the cost of delivering energy to load centres. These adjustments should consider the effects of regional load growth and possible new load centres in areas such as the North Coast, should the LNG loads develop as planned.

The associated dependable capacity provided by energy resources should continue to be valued in acquisition processes on an individual project basis. The value of the associated dependable capacity should reflect the marginal
capacity resource, which will become natural gas given that Revelstoke Unit 6 is committed for construction.

- BC Hydro should continue to purchase firm energy from IPP acquisitions, but based on the results of the study underway, should consider the tradeoff between risk and the costs associated with purchasing seasonal and contractually firm energy, as opposed to annual firm energy.

- Based on the results of the IPP acquisition analysis for the 2,000 GWh/year acquisition process, no specific financial benefit was identified with a regional acquisition process; however, a regional process may facilitate other objectives, such as economic development. BC Hydro continues to study the best options to meet the incremental load scenarios in the North Coast and has not landed on the type of acquisition process to meet these loads, should they emerge.

- If BC Hydro uses qualitative evaluation factors in future acquisition processes, it should strive to use weighting factors that are transparent.

- BC Hydro should work with the Provincial Government to assess the feasibility of developing other potentially commercial resource options, such as geothermal.

Conclusions in this IPP section support Recommended Actions No. 9 “Buy More” and No. 12 “Prepare for Potentially Greater Demand” as described in Chapter 9.

### 6.9 Transmission

The transmission grid that delivers electricity to British Columbians is divided into three major infrastructure categories – the high-voltage bulk transmission system, which carries high-voltage electricity from where it is generated to the cities, towns and industrial centres where it is consumed, the regional transmission system that distributes the medium-voltage electricity to major delivery points around the cities and towns, and the distribution system, which delivers lower voltage electricity to individual customers.
The IRP analysis examines transmission requirements in three ways.

- First, it considers the high-voltage bulk transmission system (primarily 500 kV) by analyzing the investments that may be needed to ensure the system can meet future electricity requirements. The IRP analysis takes both a 20-year and 30-year view of transmission requirements. The 30-year view is pursuant to the CEA, which requires the IRP to include a description of BC Hydro’s infrastructure and capacity needs for electricity transmission over 30 years. The longer term view reflects the long lead times required for planning, siting and constructing transmission lines.

- Second, as discussed in Chapter 2 and earlier sections of this Chapter, the IRP also examines regional transmission requirements in areas such as the North Coast and Fort Nelson/Horn River Basin, where new transmission may be an option for an area that is facing potentially significant demand growth. This section provides the transmission findings from the analysis on the incremental load scenarios for the North Coast, Northeast and general electrification. In addition, the transmission requirements under contingency events are also examined.

- Finally, the IRP also analyzes the cost-effectiveness of regional transmission requirements needed to connect clusters of new generation resources to the existing bulk transmission system (“cluster analysis”). This requirement is also pursuant to the CEA which states that the 30-year transmission analysis must also include an assessment of the potential for developing electricity generation from clean or renewable resources in B.C., grouped by geographic area.

The key IRP questions on transmission are:

- What are the transmission requirements to support load and generation build out in the Province?; and

- Whether and to what degree should BC Hydro take a more proactive approach to advancing transmission infrastructure? This proactive approach could be in
response to additional need identified in the 30-year transmission requirements or incremental load scenarios or to pre-build transmission to areas where there are generation clusters.

The key results from the transmission analysis are discussed in this section whereas details are provided in Appendix 6F.

6.9.1 20-Year Transmission Analysis: Mid-Gap

When assessing future bulk transmission system requirements, planners need to consider the following:

• The need to maintain an appropriate level of reliability for customers;
• Growth in demand by geographic area;
• Potential location and size of new generation resources;
• The need to minimize electricity losses that occur when electricity is carried over long distances; and
• The expected retirement or refurbishment of existing transmission resources.

To understand the 20-year mid-gap bulk transmission requirements, BC Hydro compared the portfolio results of a set of 20-year portfolios from the analysis in previous sections based on the mid-gap scenario (including Initial LNG). The set of portfolios covered a wide range of assumptions that might have bearing on transmission requirements, including:

• A range of DSM options;
• The inclusion and exclusion of Site C as a resource option;
• A range of five market scenarios; and
• Pumped storage in the Lower Mainland was assumed to be available to meet capacity needs.
Review of the bulk transmission requirements that result from these portfolios provides insight into the range of new transmission projects or transmission reinforcements that might be required over the next 20 years. In general, the following transmission requirements were required over most of the portfolios analyzed:

- Given the assumption of the availability of pumped storage in the Lower Mainland to meet capacity requirements, no new bulk transmission lines were required over the 20-year period. Section 6.9.3.2 discusses the transmission planning implications of this assumption.

- Non-wire reinforcements to provide voltage support in the Peace and Columbia bulk transmission systems are required. Key reinforcements in the Peace system are adding shunt compensation and/or enhancing series compensation of 500 kV lines from GM Shrum substation (GMS) to Williston substation (WSN) to Kelly Lake substation (KLY) as early as F2022. Key reinforcements in the Columbia system are series compensation of 500 kV lines 5L91 and 5L98 by F2019, which are triggered by Revelstoke Unit 6 coming online.

- The North Coast is supplied by a radial transmission line from Prince George to Terrace that consists of the following three 500 kV circuits: 5L61 from WSN to Glenannan (GLN); 5L62 from GLN to Telkwa (TKW) substation; and 5L63 from TKW to Skeena (SKA) Substation in Terrace. For the mid-gap, additional transmission reinforcements are required; all three 500 kV circuits require series compensation by F2017. Voltage support and local transmission upgrades near Kitimat will also be needed by the same time.

6.9.2 30-Year Transmission Analysis: Mid-Gap

Pursuant to the requirements of the CEA, the IRP also provides an assessment of the infrastructure and capacity needs for electricity transmission for a 30-year period. Extending the analysis from 20 to 30 years requires trending out long-term planning assumptions over an additional 10 years.
The 30-year portfolio was compared to a 20-year portfolio based on the same mid-gap scenario assumptions. Results from a review of these portfolios show that the transmission requirements for the first 20 years are identical; implying that generation and transmission build out generally follows the same order regardless of the period of optimization (i.e., 20 or 30 years). The extra 10 years of analysis indicates that two new 500 kV lines from GMS to WSN and from WSN to KLY will be required in F2035 and F2038 respectively.

Based on the results of the 30-year analysis, the following conclusions can be made:

- Extending the transmission planning time horizon from 20 years to 30 years validates the transmission choices that were identified in the initial 20-year horizon; and

- No new transmission options were identified as a result of extending the planning horizon that lead to reconsideration of options in the 20-year timeframe.

Based on these conclusions, no additional transmission requirements are required at this time as a result of the 30-year base transmission analysis.

Additional 30-year portfolios, where noted, were also created to analyze the transmission requirements for load scenarios incremental to Initial LNG.

6.9.3 Transmission Sensitivity and Incremental Load Scenario Analysis

In addition to the mid-gap analysis, the transmission requirements for a few sensitivities and incremental load scenarios were also studied to inform the development of a robust transmission plan. These contingency events and scenarios include:

- Load and DSM savings uncertainty: Here, the contingency event examined is the case where either load growth is higher than expected and DSM savings are less than expected and the corresponding implications for transmission requirements.
• Pumped storage uncertainty: This analysis tests the transmission implications if pumped storage in the Lower Mainland is not able to be developed in a significant manner and is replaced by SCGTs in the Kelly Lake region.

• Incremental load scenarios: These scenarios contemplate significant new incremental load growth in the North Coast or Northeast regions. The transmission implications of these incremental load scenarios are discussed in this section.

The results of the analysis of these contingency events and scenarios are further described in the following subsections.

6.9.3.1 Load and DSM Savings Uncertainty

The analysis on load and DSM savings uncertainty tests whether transmission requirements are affected by the larger-than-expected load-resource gap. This is evaluated by modelling portfolios based on the large-gap scenario and examining whether any new transmission requirements are identified or previously identified requirements are advanced.

The results of the analysis show that the need for voltage support along the GMS-WSN-KLY transmission corridor may be advanced to F2020. In these portfolios, additional 500 kV transmission lines between GMS and WSN (5L8) and between WSN and KLY (5L14) are also often required between F2028 and F2031.

6.9.3.2 Pumped Storage Uncertainty

As described in section 5.3.5, generic pumped storage units in the Lower Mainland are used as a clean energy capacity proxy resource in the IRP analysis to meet capacity need in the portfolios after Site C, Revelstoke Unit 6 and some biomass projects are selected. The addition of pumped storage units allows part of the peak demand in the Lower Mainland be met locally, which in turn reduces the need for transmission to bring generation capacity into Lower Mainland. In general, the addition of Lower Mainland pumped storage units has the effect of indirectly deferring transmission requirements along the ILM corridors and potentially the
GMS-WSN-KLY corridor as well, and deferring the need for other local capacity resources.

Given the development of pumped storage is unproven in B.C. (see section 6.10.3.4), prudent transmission planning must consider a contingency scenario where pumped storage is not proven out. Since the default capacity option to replace pumped storage is natural gas-fired generation, portfolios with natural gas SCGTs were created. While siting gas in Lower Mainland would be beneficial because of its proximity to load centre and reduces the need for transmission to bring generation capacity into the Lower Mainland, permitting is expected to be difficult as discussed in section 6.2. Other locations for siting gas considered, such as Kelly Lake and North Coast, would have implications on transmission requirements.

In the portfolios created to understand the effects of this potential contingency event (i.e., without pumped storage), natural gas SCGTs located in the Kelly Lake region are assumed replacing pumped storage units. The results from the portfolio analysis show that an additional transmission line (5L46) from the Interior (Kelly Lake Substation in Kamloops) to Lower Mainland (Cheekye Substation near Squamish) after ILM (5L83) may be needed by F2030 for a mid-gap case and by F2024 if large gap happens.

In addition, other transmission lines along the WSN-KLY corridor may also be necessary depending on the number of gas units sited in other locations such as North Coast.

**6.9.3.3 Incremental Load Scenarios**

The North Coast incremental load scenarios and corresponding supply options are described in section 6.5. The transmission results from this analysis are:

- For both North Coast incremental load scenarios and Supply Options A and B, a new 500 kV substation near Kitimat and two new 500 kV lines from SKA to this new substation are needed by F2020.
The need for other additional transmission requirements depends on the supply options chosen. If Supply Option B (clean energy via new transmission to the integrated system) is chosen to serve the LNG 3 load, a new 500 kV line from WSN Substation in Prince George to SKA Substation in Terrace will be required by F2020 and the need for GMS-WSN line is advanced to F2021.

For the Northeast, the Fort Nelson/HRB load scenarios and corresponding supply options are described in section 6.6. The transmission required to meet these scenarios depends on the supply option chosen. A new 500 kV line (NETL) from GMS-FTN-HRB is needed should the “clean option” be chosen. The current estimate of the earliest in service date for this line is F2019. Furthermore, a GMS-WSN line may be needed as early as F2029.

6.9.4 Cluster Analysis

In the past, B.C. Hydro has planned its transmission system in response to forecast demand growth and anticipated generation projects. This approach is increasingly subject to the following risks:

- Generation projects may be completed before transmission lines are ready or may need to be delayed until lines can be completed;
- Generation projects may develop in a way that leads to a spider web of intersecting transmission lines that are inefficient and have avoidable adverse environmental footprints; and
- New demand for electricity may occur sooner than transmission lines can be built to provide the service.

Pursuant to the CEA requirements to include an assessment of the potential for developing electricity generation from clean or renewable resources in B.C. grouped by geographic area and as part of the IRP analysis and ongoing planning work, BC Hydro considered where the largest potential exists for low-cost clean generation options. Rather than responding to individual projects, this planning process identifies where clusters of projects could appear across the province (i.e., regions.
with a combination of run-of-river, wind or biomass potential) and the costs, benefits and risks of pre-building transmission to access these generation clusters.

The IRP cluster analysis considers the following questions:

- What are the benefits and costs of pre-building transmission to areas with high concentration of generation resources? In addition to financial considerations, other potential benefits could include minimizing environmental footprint through avoiding an excessive number of transmission corridors in an area or fostering economic development in an area.

- What are the risks associated with pre-building transmission in advance of generation project development? One key risk factor is that transmission investment may be stranded if generation resources do not develop as expected.

These questions are explored in the following section by comparing portfolios created according to the following two approaches:

- **Bundle approach:** The traditional evaluation framework used in resource planning reflects the current approach to interconnecting individual generation projects to existing transmission grid. Each project within a bundle has a separate transmission connection to the system.

- **Cluster approach:** The approach of pre-building bulk transmission into a region of high generation resource potential. A cluster is a geographic area where there is high energy and/or capacity density.

### 6.9.4.1 Cluster Identification

The first step of the cluster analysis was to identify areas of high density of generation resource potential – i.e., generation clusters – that are remote from the existing transmission grid in B.C. The cluster is generally defined as: (1) a region with a density of 0.06 MW/km² and a minimum of 500 MW generating capacity and (2) at least 50 km away from the bulk transmission system.
For each cluster, an assumption was made on the location of a central node that represents a potential new transmission substation based on geography, proximity of generation resources and professional judgement. This central node is assumed to be the collector hub for the electricity generated from the resources within the cluster. The next step in the cluster analysis is to determine the length and cost of a bulk transmission line connecting the central node to the existing transmission grid. These line options are referred to T3 options in the following discussion.

Kerr Wood Leidal was engaged by BC Hydro to perform this cluster and T3 option identification exercise. A report describing the approach, results and T3 options is included in Appendix 6G. The nine clusters and the corresponding central nodes are identified below and in Figure 6-26:

- North Peace River (NPR): would connect to GMS;
- Fort Nelson (FTN): would connect to NPR;
- Liard (LRD): would connect to FTN and then connect to NPR;
- Telegraph Creek (TGC): will connect to the future Bob Quinn Substation (BQN);
- Dease Lake (DLK): would connect to TGC;
- Hecate (HCT): would connect to Skeena Substation (SKA);
- Knight Inlet (KTI): would connect to Dunsmuir Substation (DMR) on Vancouver Island;
- Bute Inlet (BUI): would connect to DMR; and
- North Vancouver Island (NVI): would connect to DMR.

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41. T3 Options’ builds off terminology used by BC Hydro in its resource options assessment to categorize the types of power lines required to connect new generation projects to the transmission system. Refer to Appendices 3A or 6G for more information.

42. The region around Fort Nelson did not have greater than 500 MW of potential generation resources in close proximity and therefore did not meet the definition of a generation cluster. However, it is recognized as having load growth potential and was therefore considered in the analysis.
As seen in Figure 6-26 below, the central nodes are labeled as “new nodes” and the area of clusters are delineated by red borders. As a general observation, many of the clusters are located on the periphery of the province, reflecting that there is additional generation potential in the province in areas less densely covered by transmission, which may result in reduced access to the existing transmission system.

**Figure 6-26  Cluster Analysis Nodes**

6.9.4.2 **Portfolio Analysis and Full Consequence Table**

To analyze whether there is a potential benefit of pre-building transmission for generation clusters, a 30-year portfolio was created using the cluster approach according to the mid-gap scenario assumptions. The System Optimizer model was given the option to select T3 options, and the cost of interconnection for generation resources was adjusted to the central nodes. The present value of this cluster portfolio was then compared to the corresponding portfolio with a bundle approach.
Portfolios based on the cluster and bundle approaches were also compared on their environmental and economic development attributes.

Table 6-26 shows there is benefit with the cluster approach, but that the estimated benefit is only marginal. This result is based on the resource selection being optimized given perfect foresight of future conditions within the portfolio construct. Furthermore, the costs and availability of resources analyzed represent planning level estimates with corresponding uncertainty. Given these factors, the difference in results between the portfolios is not significant enough to clearly recommend the cluster approach.

In addition and in practice, the cluster approach also assumes the risk of stranded or under-utilized transmission assets that represent significant expenditures. The cluster approach may also have potential negative impacts on bidding behaviour in a potential future acquisition process, which could erode any benefits.

<table>
<thead>
<tr>
<th>Measure</th>
<th>Results – Bundle</th>
<th>Results – Cluster</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land</td>
<td>total hectares</td>
<td>25,100</td>
</tr>
<tr>
<td>Affected Stream Length</td>
<td>km</td>
<td>390</td>
</tr>
<tr>
<td>Marine (valued ecological features)</td>
<td>total hectares</td>
<td>150</td>
</tr>
<tr>
<td>Total GDP</td>
<td>$ million PV</td>
<td>13,900</td>
</tr>
<tr>
<td>Employment</td>
<td>Total FTEs</td>
<td>350,500</td>
</tr>
<tr>
<td>Gov't Revenue</td>
<td>$ million PV</td>
<td>2,200</td>
</tr>
<tr>
<td>G&amp; T Resource cost</td>
<td>$ millions PV</td>
<td>12,250</td>
</tr>
<tr>
<td>Trade Revenue</td>
<td>$ millions PV</td>
<td>-1,215</td>
</tr>
<tr>
<td>DSM Option cost</td>
<td>$ millions PV</td>
<td>3,996</td>
</tr>
<tr>
<td>Total Portfolio Cost</td>
<td>$ million PV</td>
<td>15,031</td>
</tr>
</tbody>
</table>
The environmental footprint and economic development results from the bundle and cluster approaches are also compared in Table 6-26. Some of the key findings are:

- As expected, the cluster approach reduces the land footprint since it decreases the amount of redundant lines being built.
- The affected stream length result highlights that these modelling outcomes can appear quite lumpy and counterintuitive when taken down at micro/project level.
- Both the bundle and cluster approach have similar economic development impacts.

**North Peace River Cluster Benefits**

One of the clusters, the NPR, was further analyzed because it is situated along potential path of the NETL and may offer benefits that can offset the cost of this line. In this analysis, two 30-year portfolios both meeting the mid-gap were created, one using the bundle approach (interconnecting individual projects in NPR to existing GMS substation) and one using the cluster approach (building a bulk transmission line from GMS to a potential substation at NPR) were created. The higher present value for the NPR cluster portfolio, as shown in Table 6-27, means that the benefit of building out the NPR cluster does not fully offset the cost of the GMS to NPR transmission line over the planning horizon. However, the difference in portfolio cost without the cost of the T3 line from the Peace Region could be used to offset the cost of the NETL because the NETL enables access to the NPR cluster. By assuming the annual benefit at the end of the 30-year portfolio persists until the end of the project life of NETL, the benefit associated with the NPR cluster is about $150 million.

| Table 6-27 Cost Comparison for Bundle and NPR Cluster (PV, $ million) |
|------------------------|----------------|----------------|------------|
| 30 year PV             | Bundle         | NPR Cluster    | Difference |
| Total Portfolio Cost   | 15,031         | 15,143         | -112       |

"BCHydro"
6.9.4.3 Simple Cost Analysis for Clusters

Apart from the portfolio analysis described in section 6.6.4.2, a simple analysis of estimating potential cost savings for the cluster approach was completed to understand potential benefits in the long run (beyond the planning timeframe). The potential cost savings were estimated as the annual difference in cost, between the two approaches, incurred up to the POI at existing transmission grid (i.e., the bundle approach includes the generation resource cost and interconnection cost (T1) to the POI; the cluster approach includes the generation resource cost and interconnection cost (T2) to T3 and the cost of T3 from the respective central nodes to POI. As an example of the analysis, Figure 6-27 shows a comparison of costs for the bundle approach versus the cluster approach for a 500 kV T3 option connecting to the NPR node. For the bundle approach, the weighted average cost of resources increases as increasingly more expensive projects are interconnected. The cluster approach has a higher weighed average cost than the bundle approach when only a few projects are interconnected, but the cost decreases as more resources are interconnected as utilization of the T3 line is increased. At some point, the weighted average cost for the cluster approach may increase again, as the addition of more expensive resources outweigh the benefit of higher utilization of T3 line. In this example, 800 MW of resources have to be built for the cluster approach to yield lower average cost than the bundle approach. This speaks to the risk of stranded assets if the T3 line is built, but the assumed generation resources in the cluster are not needed or are not developed.
The analysis was completed for each cluster that does not depend on other clusters. In other words, if the logical sequence is to build from the existing grid to TGC before DLK, this analysis would only examine TGC but not DLK. The analysis is limited to these clusters as the complex economic analysis of dependent clusters is best handled in portfolio analysis.

The resulting weighted average costs and total costs from the two build-out approaches for two T3 sizes (i.e., 230 kV and 500 kV where meaningful) are summarized in Table 6-28 to Table 6-31. These annualized costs reflect the condition when the lines are close to fully utilized. As shown in these tables, the cluster approach is generally of lower cost than the bundle approach for clusters studied, except for the NPR and NVI clusters with a 230 kV line, and the HCT cluster with the 500 kV line. This confirms the intuition that the cluster approach generally has a cost advantage in the long run when the line is fully utilized. However, there is uncertainty regarding resource development leading to risk of stranded/underutilized asset, and uncertainty as to when benefit can outweigh cost. As shown in the tables
below, the cluster approach does not yield clear benefit within the planning time frame.

### Table 6-28 Comparison of UEC costs for the bundle approach and the cluster approach with a 230 kV line

<table>
<thead>
<tr>
<th>Cluster</th>
<th>Bundle</th>
<th>Cluster (230 kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>UEC_gen + T1 ($/MWh)</td>
<td>UEC_gen + T2 + T3 ($/MWh)</td>
</tr>
<tr>
<td>NPR</td>
<td>104</td>
<td>115</td>
</tr>
<tr>
<td>TGC</td>
<td>236</td>
<td>154</td>
</tr>
<tr>
<td>NVI</td>
<td>138</td>
<td>164</td>
</tr>
<tr>
<td>KTI</td>
<td>114</td>
<td>84</td>
</tr>
<tr>
<td>BUI</td>
<td>101</td>
<td>73</td>
</tr>
</tbody>
</table>

### Table 6-29 Comparison of UEC costs for the bundle approach and the cluster approach with a 500 kV line

<table>
<thead>
<tr>
<th>Cluster</th>
<th>Bundle</th>
<th>Cluster (500 kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>UEC_gen + T1 ($/MWh)</td>
<td>UEC_gen + T2 + T3 ($/MWh)</td>
</tr>
<tr>
<td>NPR</td>
<td>118</td>
<td>110</td>
</tr>
<tr>
<td>TGC</td>
<td>670</td>
<td>476</td>
</tr>
<tr>
<td>HCT</td>
<td>144</td>
<td>148</td>
</tr>
<tr>
<td>NVI</td>
<td>154</td>
<td>151</td>
</tr>
<tr>
<td>KTI</td>
<td>213</td>
<td>129</td>
</tr>
<tr>
<td>BUI</td>
<td>192</td>
<td>123</td>
</tr>
</tbody>
</table>

### Table 6-30 Comparison of total costs for the bundle approach and the cluster approach with a 230 kV line

<table>
<thead>
<tr>
<th>Cluster</th>
<th>Bundle</th>
<th>Cluster (230 kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>UEC_gen + T1 ($M)</td>
<td>UEC_gen + T2 + T3 ($M)</td>
</tr>
<tr>
<td>NPR</td>
<td>94</td>
<td>103</td>
</tr>
<tr>
<td>TGC</td>
<td>245</td>
<td>165</td>
</tr>
<tr>
<td>NVI</td>
<td>76</td>
<td>91</td>
</tr>
<tr>
<td>KTI</td>
<td>132</td>
<td>99</td>
</tr>
<tr>
<td>BUI</td>
<td>138</td>
<td>96</td>
</tr>
</tbody>
</table>
### Table 6-31
Comparison of the total costs for the bundle approach and the cluster approach with a 500 kV line

<table>
<thead>
<tr>
<th>Cluster</th>
<th>Bundle UEC_gen + T1 ($M)</th>
<th>Cluster (500 kV) UEC_gen + T2 +T3 ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPR</td>
<td>423</td>
<td>374</td>
</tr>
<tr>
<td>TGC</td>
<td>2,071</td>
<td>1,471</td>
</tr>
<tr>
<td>HCT</td>
<td>297</td>
<td>294</td>
</tr>
<tr>
<td>NVI</td>
<td>458</td>
<td>339</td>
</tr>
<tr>
<td>KTI</td>
<td>1,105</td>
<td>664</td>
</tr>
<tr>
<td>BUI</td>
<td>702</td>
<td>448</td>
</tr>
</tbody>
</table>

#### 6.9.5 Conclusions

The IRP analysis leads to the following key conclusions on transmission reinforcements:

- In general, the 20-year transmission analysis on the mid-gap scenario identified locations where transmission upgrades are required; however, with the exception of some contingency conditions, no new transmission lines are required over the next 20 years.

- North Coast: The inclusion of Initial LNG in the base load requirement assumption requires installing adequate shunt support and adding series compensation to the existing 500 kV lines from WSN to SKA by F2017. No new transmission ROW is required. The extent to which some level of series compensation is required in the absence of Initial LNG, but with other North Coast load growth (e.g., mining load development), will require further study.

- North Coast incremental load scenarios would require a 500 kV substation near Kitimat and two new 500 kV lines from SKA to this new substation by F2020. Depending on the decisions regarding the supply of additional LNG customers in the North Coast, a second 500 kV line from WSN to SKA may be needed as early as F2020 if Supply Option B (clean energy via transmission to the integrated system) is chosen. The study of this line should continue in order to preserve this supply option as discussed in section 6.5.
• Peace: Non-wire upgrades to the existing transmission lines and substations on the GM Shrum Substation (West of Fort St. John) to Williston Substation (Prince George) to Kelly Lake Substation (Kamloops) 500 kV transmission system will be required as early as F2022 in the mid-gap and F2020 in the large gap. New 500 kV transmission line from WSN to KLY may be needed in a mid-gap and large gap case by F2038 and F2028 respectively. New transmission line from GMS to WSN may be needed by F2028 in the large gap case but need may be advanced to F2021 depending on supply option for additional LNG customers in the North Coast.

• Columbia: Non-wire upgrades to the 500 kV lines of 5L91 and 5L98 are needed. These are tied to the need for Revelstoke Unit 6 which has an estimated earliest in service date of F2019.

• Transmission planning should be informed by the outcome of the investigation of feasibility of pumped storage facilities in the Lower Mainland. The alternative default capacity option is to use gas at Kelly Lake and would require a new transmission line from Interior to Lower Mainland by F2030 in the mid-gap and F2024 in the large-gap. Depending on the siting of the gas units, other transmission line may also be advanced (e.g., WSN to KLY if gas sited at North Coast).

• Extending the transmission planning horizon from 20 years to 30 years validates the transmission choices that were identified in the initial 20-year horizon. No new transmission options were identified as a result of extending the planning horizon that would have caused reconsideration of options in the 20-year timeframe.

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

The IRP analysis concludes that there could be marginal financial benefits in pre-building transmission into clusters of generation resources over the planning horizon. It also shows there is potential to reduce environmental footprints somewhat as a result of optimal transmission configurations. The economic development impacts of the bundle and cluster approaches were similar.

Meanwhile, there are also significant risks associated with pre-building transmission for generation clusters that include:

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

To reap some potential pre-building benefits while minimizing risk, BC Hydro could evaluate building adequate transmission to the identified high potential generation cluster regions during future acquisition processes if and when projects in these regions are proposed. This analysis aligns with the additional IRP activities present in the cluster analysis in section 9.5.3 of Chapter 9.

The NPR cluster could provide an estimated $150 million of benefit to offset the cost of NETL.

Conclusions in this transmission section support Recommended Actions No. 8 (Build Reinvest More) and No. 11 (Prepare for Potentially Greater Demand) as described in Chapter 9.
6.10 Capacity and Contingency Analysis

6.10.1 Introduction

Having determined what resources to acquire and build that provide both energy and capacity contributions as discussed in the previous chapters, the IRP determines a set of recommended actions for additional capacity resources to ensure a cost effective, clean and adequate supply of reliable electricity to meet forecasted peak demand. Ensuring an adequate capacity supply is the primary concern for BC Hydro since capacity is required at specific times to meet peak load requirements and maintain system security and reliability. Capacity resources also support other intermittent generation resources that supply primarily energy so that generation is available when the loads require it.

BC Hydro plans capacity resources under the following conditions:

- To meet the most likely mid-gap conditions;
- To provide options to meet contingency large-gap conditions. Contingencies include significant planning uncertainties such as load growth being greater than expected, planned resources under-delivering, and supply-side capacity contributions being less than expected; and
- To provide or maintain options to supply incremental load scenarios such as additional North Coast LNG load growth.

The uncertainty in the size of the capacity gap has been partly described with the three gap scenarios as discussed in section 5.2.3.3. The need for new capacity resources in the future has additional uncertainty because of potential additional load scenarios like LNG 3, High Mining and FN/HRB electrification, as discussed in section 2.2; and the amount of capacity that is associated with energy that may be acquired from other sources, in this case DSM or acquisition processes. For these

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43 The gap scenarios represent three potential net loads after DSM: the small-gap is BCH’s low load less high DSM; the mid-gap represents BCH’s most likely load after the most likely DSM savings and the large-gap represents BCH’s high load forecast less low DSM savings. This is described further in section 5.2.
sources of uncertainty, the risk is that BC Hydro may end up short of capacity either
at the system level or in a specific load region.

The capacity resource actions that are derived from these contingency conditions
are then considered with load uncertainties to prepare specific Contingency
Resource Plans (CRPs) that will be used in the analysis of associated transmission
requirements. The CRPs are described further in Chapter 9.

6.10.2 Need for Capacity

The yearly forecast peak capacity requirements (excluding planning reserve
requirements) are shown in Figure 6-28 reflecting both the original mid-gap (in blue)
consistent with the requirements presented in section 2.4 and the mid-gap after
DSM Option 3, Site C44 and the capacity from 2,000 GWh/year of clean IPP
acquisitions (in light green). The capacity and energy benefits of Site C were
discussed in section 6.4 and it is recommended to continue to be built. After the
actions above approximately 300 MW of additional capacity is required in F2016,
growing to approximately 1,100 MW in F2021 and reducing to approximately
150 MW in F2022 with the addition of Site C, and then continuing to grow again up
to approximately 1,500 MW in F2031.

44 Although the in-service date for Site C is in F2021, the estimated schedule of the six units coming online
indicates that there will not be any dependable capacity available to serve winter peak load until the following
year (F2022). The gap reduces by approximately 950 MW with the addition of Site C’s effective load carrying
capability (1,100 MW * 0.86).
6.10.3 Capacity Resource Options

BC Hydro prepared an inventory of available capacity resource options as provided in Table 6-32. This table shows the capacity potential, lead time, UCC and some key considerations for each option. When considering resources to meet capacity requirements, BC Hydro must examine all of these variables to prepare its recommended options.
### Inventory of Capacity Resource Options

<table>
<thead>
<tr>
<th>Resource Option</th>
<th>Potential (MW)</th>
<th>Lead Time (years)</th>
<th>Cost at Point Of Interconnection ($/kW-yr)</th>
<th>Key Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market</td>
<td>Variable up to 2,000 MW</td>
<td>0</td>
<td>10 – 36</td>
<td>Not long-term resource but readily available</td>
</tr>
<tr>
<td>Canadian Entitlement (CE)</td>
<td>1,200</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burrard</td>
<td>900</td>
<td>15 – 73</td>
<td></td>
<td>Conventional, clean and long-term but not available in near-term</td>
</tr>
<tr>
<td>Revelstoke Unit 6</td>
<td>500</td>
<td>6</td>
<td>55</td>
<td>Conventional, not clean, available near-term and long-term</td>
</tr>
<tr>
<td>Gas</td>
<td>100 (per unit)</td>
<td>4 – 5</td>
<td>70</td>
<td></td>
</tr>
<tr>
<td>Resource Smart</td>
<td>TBD</td>
<td>TBD</td>
<td>TBD</td>
<td>Conventional, clean, uncertain in terms of impacts/operations and/or development</td>
</tr>
<tr>
<td>Mica Pumped Storage</td>
<td>500</td>
<td>6</td>
<td>112</td>
<td></td>
</tr>
<tr>
<td>Pumped Storage (LM/VI)</td>
<td>500 – 1000 (per unit)</td>
<td>8</td>
<td>96</td>
<td></td>
</tr>
<tr>
<td>DSM – Load Curtailment</td>
<td>~ 300</td>
<td>2</td>
<td>32</td>
<td></td>
</tr>
<tr>
<td>DSM – Capacity Programs</td>
<td>~200</td>
<td>2</td>
<td>53</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**

1. DSM values are defined as capacity potential in F2030.
2. SCGT and Pumped Storage fuel costs are not included.
3. Revelstoke Unit 6 values based on the 2008 LTAP escalated to $2011.
4. A SCGT representative project is used to characterize the Natural Gas resource option.
5. Values for Market/CE/Burrard capacity are theoretical potential.

**6.10.3.1 Market Purchases, Canadian Entitlement and Burrard**

As set out in section 2.3, market purchases, CE and Burrard are not categorized as long-term resource options because BC Hydro is precluded from planning to rely on them for its long-term plan. However, they are available for contingency or bridging purposes.
The potential shown in Table 6-32 for market, CE and Burrard is based on intertie import ratings, the full CE treaty availability and Burrard’s nameplate capability respectively. However, BC Hydro estimates that in practice market purchases backed up by CE would be available to supply BC Hydro with a minimum of 500 MW given current transmission availability through the I5 corridor during peak winter conditions when US utilities have similar very high load conditions. The range of costs to rely upon market backed up by CE is shown in Table 6-33.

As described in section 2.3.2.1, under the CEA BC Hydro is currently able to rely on 900 MW from Burrard Thermal for emergency purposes and by regulation until Mica 5/6, ILM and the third Meridian transformer are in place which is expected in F2016. In September 2010, BC Hydro established an operating and investment plan for Burrard for the period F2012 through F2016 that contemplated four generating units being available as needed and two generating units in recallable storage45. Subsequently, BC Hydro determined that only three generating units would be made available. This was done to reduce costs and to better manage the risk of retaining qualified staff to manage BC Hydro’s portfolio of thermal generation capital projects between Burrard and Fort Nelson. Given the current state of the three units BC Hydro estimates that a reasonable contingency reliance would be for up to 450 MW (three generating units) plus a fourth unit available as reserves. If Burrard were to be relied upon beyond F2016 or to make the fourth unit available prior to F2016 would require the cost estimates shown in Table 6-33.

45 BC Hydro estimates that these units would take two to eight months to recall from storage.
Table 6-33  Bridging Option UCC and Description

<table>
<thead>
<tr>
<th>Resource Option</th>
<th>UCC&lt;sup&gt;46&lt;/sup&gt; ($/kW-year)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market / CE</td>
<td>10</td>
<td>Lower end of opportunity cost reflecting BC Hydro’s estimate of the incremental reliability premium that a purchaser would pay for a multi-day block of CE.</td>
</tr>
<tr>
<td></td>
<td>36</td>
<td>Upper end of opportunity cost reflecting BC Hydro’s estimate of the price that a purchaser would pay for a multi-day block of regulating reserve in the winter based on recent transactions in the Pacific Northwest.&lt;sup&gt;47&lt;/sup&gt;</td>
</tr>
<tr>
<td>Burrard</td>
<td>15</td>
<td>Incremental cost of maintaining a fourth 150 MW unit over and above cost of maintaining three units (450 MW).</td>
</tr>
<tr>
<td></td>
<td>73</td>
<td>Cost of maintaining four 150 MW units.</td>
</tr>
</tbody>
</table>

6.10.3.2  Revelstoke Unit 6
Revelstoke Unit 6 is categorized as conventional, clean and long-term but not available until F2019. Chapter 3 discusses its low cost and ancillary benefits (e.g., flexibility, dispatchability, firming and shaping benefits).

6.10.3.3  Natural Gas Capacity Resource Options
As described in section 6.2, cost-effective natural gas capacity resources hold special value as a resource for capacity planning, transmission alternatives and contingency planning. The shorter lead time of this resource means that gas could potentially be used to meet identified capacity shortfalls in the near-term.
If natural gas is chosen to deal with near-term capacity shortfalls and it is sited in a location where forecasted BC Hydro load doesn’t materialize as expected then this resource decision is sub-optimal; operating remote gas plants to support the system may entail transmission losses, may trigger unnecessary transmission upgrades, and more importantly, such a move would prevent the opportunity to use gas plants to avoid transmission upgrades within the 7 per cent non-clean headroom.

<sup>46</sup> Ranges of costs are preliminary estimates.
<sup>47</sup> Based upon recent market transactions such as the NorthWestern Corporation 2009 “Regulating Reserve Services” two-year agreement.
As discussed in section 6.2, there may also be siting and permitting risks associated with building gas facilities in B.C. Current considerations for locations of gas facilities are in the North Coast, Kelly Lake, Vancouver Island and Fort Nelson.

6.10.3.4 Resource Smart, Pumped Storage and DSM Capacity Options

Resource Smart, pumped storage and DSM capacity options are conventional, clean and long-term capacity resource options, but they are also uncertain in terms of development and/or operations. These resources have the potential to offer a significant amount of clean and long-term capacity.

Additional Resource Smart opportunities like capacity upgrades at the G.M. Shrum facility have been identified but more work needs to be done to prepare an inventory of additional cost-effective resource smart potential and associated in-service timing to look at how this potential could be used to meet capacity shortfalls.

The ‘uncertain’ characterization for pumped storage and DSM capacity options is intended to signify that BC Hydro will need to pursue further actions to gain more certainty about the impacts and implementation of these options before planning to rely on them to meet capacity shortfalls. Although pumped storage has been seen in other regions in North America, there is still uncertainty about the siting and permitting requirements in B.C. The Mica pumped storage option, discussed in Chapter 3, has seasonal shaping capability which offers additional benefits in managing the freshet oversupply issue (discussed in section 6.8.4.6) by using low-price freshet energy for pumping and saving the energy for higher value periods.

For DSM capacity options, BC Hydro has had experience with load curtailment, but has not yet sought to extend curtailment to longer term contracts that allow customers to invest in facilities and make a firm longer term commitment\(^\text{48}\), and BC Hydro has not implemented capacity-focused DSM programs before. To the extent that BC Hydro can achieve certainty that the resources will be available as

\(^{48}\) BC Hydro would require a longer term commitment to both reduce long-term capacity requirements and allow for the replacement of such capacity if a customer no longer wishes to participate in such a program.
required and the resources continue to be cost-effective, these resources can
displace less cost-effective capacity options.

6.10.4 Uncertainties

There are a number of uncertainties and risks that BC Hydro considers in its
resource planning and analysis. The major risks are managed either by
recommending actions that avoid or minimize risks or, consistent with good utility
practice and the BCUC’s Resource Planning Guidelines, by developing contingency
plans that seek to mitigate the major risks inherent in the actions selected.
BC Hydro’s long-term plans for capacity must be able to respond to a range of
uncertainties. Table 6-34 demonstrates the capacity requirements under BC Hydro’s
most likely mid-gap but the uncertainties described in Table 6-34 must also be
considered in preparing recommended IRP actions for capacity resources that are
flexible to respond to changes in capacity requirements. Table 6-34 describes each
uncertainty in terms of its potential impact on the need for capacity, the type of
indication that would let BC Hydro know that a change has occurred and the amount
of warning time that BC Hydro would likely have to respond from the time of
indication of a change to the requirement to serve. BC Hydro has categorized the
uncertainties by three important traits:

(i) Timing in which a change to the capacity requirements may occur (near-term or
long-term);
(ii) Whether or not BC Hydro would have sufficient time to react to a change; and
(iii) Whether the change will happen gradually or immediately with a specific
‘signpost’ that indicates that there is a change in capacity requirements.

BC Hydro is most concerned with uncertainties in the near-term and inadequate
response time.
### Table 6-34  Capacity Need Uncertainties

<table>
<thead>
<tr>
<th>Category</th>
<th>Uncertainty</th>
<th>Potential Impact</th>
<th>Leading Indicator</th>
<th>Number of Years of Advance Warning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Near-Term, Possible Insufficient Reaction Time, Gradual</td>
<td>Load</td>
<td>+/- 600 MW in F2017</td>
<td>Year-by-year load growth</td>
<td>1-4</td>
</tr>
<tr>
<td></td>
<td>DSM</td>
<td>+/- 400 MW in F2017</td>
<td>Year-by-year load growth</td>
<td>1-4</td>
</tr>
<tr>
<td>Near-Term, Possible Insufficient Reaction Time, Signpost</td>
<td>Wind ELCC</td>
<td>Up to -150 MW in F2017</td>
<td>Experience &amp; Internal analysis</td>
<td>1-4</td>
</tr>
<tr>
<td>Near-Term, Sufficient Reaction Time, Signpost</td>
<td>LNG 3 &amp; High Future Mining</td>
<td>+ 1,500 MW in F2021</td>
<td>Customer requests</td>
<td>3-4</td>
</tr>
<tr>
<td></td>
<td>High FN / HRB</td>
<td>+ 600 MW in F2021</td>
<td>NETL commitment</td>
<td>4</td>
</tr>
<tr>
<td>Long-Term, Sufficient Reaction Time, Signpost</td>
<td>Site C</td>
<td>Material delay up to 1,100 MW</td>
<td>Approvals to proceed; In-service date.</td>
<td>4</td>
</tr>
<tr>
<td>Long-Term, Sufficient Reaction Time, Gradual</td>
<td>Electrification</td>
<td>Growing to 2,600 MW in F2031 (E3)</td>
<td>Gov't policy, load growth, technology</td>
<td>3-6</td>
</tr>
</tbody>
</table>

BC Hydro considers the inventory of available capacity resources in conjunction with the list of uncertainties to prioritize resource options that can be used to respond to changes in need as they happen.

The first three uncertainties – Load, DSM and Wind ELCC – fall into the category of near-term and possible insufficient reaction time. The characteristics of the other uncertainties show that their impact is either far enough away or there is a signal with sufficient reaction time available for BC Hydro to respond with new capacity resources.

### 6.10.5 Base Resource Planning for Capacity

BC Hydro’s Base Resource Plan (BRP) for capacity identifies actions to pursue for capacity resources to meet the mid-gap. In particular it identifies both specific
actions to meet near-term requirements and more general actions that BC Hydro must do to ensure long-term needs can be met.

### 6.10.5.1 Revelstoke Unit 6

The green solid line in Figure 6-29 below shows the remaining gap after the resources shown in Figure 6-28 and after accounting for Revelstoke Unit 6.

![Figure 6-29](image)

**Figure 6-29** Capacity Requirements under Mid-gap with DSM Option 3, Clean IPPs, Site C and Revelstoke Unit 6

After Revelstoke Unit 6 and Site C come online with their large capacity contributions, there becomes a clear division between the near-term and long-term need for capacity. There is a need for approximately 800 MW of near-term capacity in the F2016 to F2021 time frame. The addition of Revelstoke Unit 6 and Site C creates surplus capacity (up to about 250 MW) in F2022 and F2023. Figure 6-29
indicates that BC Hydro will need additional sources of capacity supply in F2024 and beyond.

The purple line in Figure 6-30 shows the need for Revelstoke Unit 6 at its earliest in-service date without the load from Initial LNG.

BC Hydro is recommending advancing Revelstoke Unit 6 to its earliest in-service date as the most cost-effective way to meet the self-sufficiency obligations of approximately 1,100 MW in the next 10 years. In addition, given the uncertainty in the regulatory process and schedule for Site C, as described in Chapter 9, the Revelstoke capacity could contribute to managing any changes to the Site C in-service timing.
6.10.5.2 Near-Term Capacity Portfolio Analysis

Given the near-term resource availability identified in section 6.10.3, BC Hydro undertook portfolio analysis on the two reliable alternatives for meeting near-term BRP capacity shortfalls (under mid-gap conditions):

- Bridge the near-term capacity shortfalls through to the building of Revelstoke Unit 6 and Site C with a combination of short-term capacity resource options: market backed by CE and Burrard for a combined total of 900 MW (bridging strategy or bridging resources); and
- Build 700 MW of natural gas SCGTs in the North Coast in anticipation of future load growth.

BC Hydro assumed that the 900 MW of bridging resources would be supplied by 450 MW from market and CE and 450 MW from Burrard. The bridging cost was calculated over a range from low market capacity cost / low Burrard maintenance costs to high market capacity cost / high Burrard maintenance costs as described in section 6.10.3. The analysis compared the two alternatives for the following four conditions:

- Market Scenario C (low electricity price, most likely case), low cost for bridging resources;
- Market Scenario C, high cost for bridging resources;
- Market Scenario B (mid electricity price), low cost for bridging resources;
- Market Scenario B, high cost for bridging resources.

The capacity portfolio analysis is based on DSM Option 2 because it was completed prior to the recommendation to pursue DSM Option 3; however, it is not expected that there would be a material impact on the conclusions in this section as a result of such a change. Using DSM Option 2, 900 MW of capacity supply was required in the near term.

Although the analysis was on gas and bridging, BCH’s recommended actions will consider other options for meeting near-term capacity requirements should they prove to be available, reliable and cost-effective.

Net of reserve requirements 700 MW of gas only contributes approximately 600 MW toward meeting system peak. This means an additional 300 MW of bridging support would still be required in the near-term to meet the most likely gap.

The earliest in-service date of gas is F2017 or F2018. In this scenario, BCH would need to rely on over 400 MW in F2016 to meet near-term capacity requirements.
A comparison of the portfolio costs for the two alternatives are summarized Figure 6-31 and Table 6-35.

Figure 6-31 PV Analysis Results: Mid-gap

![Graph showing PV Analysis Results: Mid-gap](image)

Table 6-35 PV Analysis Results: Mid gap

<table>
<thead>
<tr>
<th>Near-term Capacity Option</th>
<th>Market Scenario C</th>
<th>Market Scenario B</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low Bridging Cost</td>
<td>High Bridging Cost</td>
</tr>
<tr>
<td>Bridging</td>
<td>8,609</td>
<td>8,823</td>
</tr>
<tr>
<td>Gas</td>
<td>8,588</td>
<td>8,602</td>
</tr>
<tr>
<td></td>
<td>8,050</td>
<td>8,264</td>
</tr>
<tr>
<td></td>
<td>8,152</td>
<td>8,166</td>
</tr>
</tbody>
</table>

The analysis showed that:

- In three of four conditions, the portfolio with gas-fired generation was less expensive than the portfolio with the bridging option.
• When the bridging cost is low and market cost is higher (Market Scenario B), the portfolio with the bridging option is cheaper.

• In all these conditions, the relative costs and benefits were small (less than 3 per cent of portfolio costs) compared to portfolio PV cost.

However, while the portfolios with gas-fired generation result in cost savings in the majority of cases, the savings were small and the savings were likely as a result of the assumption to rely upon associated gas energy (using an 18 per cent capacity factor as discussed in section 6.2) to displace clean energy. If a similar energy reliance were to have been placed upon the bridging resources, they likely would have been the lower cost. Further, higher gas costs would reduce or even eliminate the cost savings. Lastly, although analysis using an energy reliance for the bridging option would likely have changed the PV results in favour of the bridging option, it is likely that the relative differences between portfolios would remain small.

This analysis did not point to a preferred option. However, as described in section 6.2, the preferred location for siting gas is uncertain and there is value to preserving gas as a transmission alternative. Lost opportunity cost for the gas strategy has not been captured in the gas strategy analysis. By using gas to meet system requirements gas is no longer preserved as a potential higher value transmission alternative within the 93 per cent clean objective.

6.10.5.3 Capacity Regret Analysis

An additional capacity regret analysis was undertaken to help inform the recommendation of capacity resources to supply the near-term gap. This capacity regret analysis looks at the impacts of making a decision to rely on either the market/CE and Burrard or gas-fired generation and ending up with a large or small gap. The decision tree for the BRP capacity analysis shown in Figure 6-32 demonstrates the three discrete potential gap size outcomes: (A) large-gap; (B) mid-gap; and (C) small-gap for each near-term capacity resource strategy (1) Bridging; and (2) Gas and the relative likelihood of each outcome. The process
for preparing the relative likelihoods for the three potential outcomes is described in Appendix 5B.

Figure 6-32 BRP Decision Tree

Near Term Capacity Strategy

<table>
<thead>
<tr>
<th>Near Term Outcome</th>
<th>Relative Likelihood</th>
</tr>
</thead>
<tbody>
<tr>
<td>(A) Large Gap</td>
<td>10%</td>
</tr>
<tr>
<td>(B) Mid Gap</td>
<td>80%</td>
</tr>
<tr>
<td>(C) Small Gap</td>
<td>10%</td>
</tr>
</tbody>
</table>

Base Resource Plan

(1) Rely on Market backed by CE+BGS
- (A) Large Gap 10%
- (B) Mid Gap 80%
- (C) SmallGap 10%

(2) Build 700 MW SCGTs
- (A) Large Gap 10%
- (B) Mid Gap 80%
- (C) Small Gap 10%

Large Gap Regret/Risk Analysis

If BC Hydro were to plan to rely on market/CE and Burrard, Figure 6-33 demonstrates that an additional 1,100 MW could be required in the near-term period if the large gap materializes (Near-term Outcome 1A). This means that BC Hydro will need to have additional gas-fired capacity resources available to respond if the change in need is indicated.
Figure 6-33 demonstrates that if BC Hydro were to plan to build 700 MW of new gas capacity to meet near-term requirements and the large gap materializes (near-term Outcome 2A), even with a full reliance on market/CE and Burrard, there could still be a need for additional capacity in the range of 500 MW.
BC Hydro concluded that there is little material difference between these two strategies if the large gap materializes because in both cases a combination of bridging and gas would be required at the same time so the order of commitment becomes irrelevant and results in similar portfolio costs. There may be some benefit to building gas-fired generation initially to reduce the potentially large amount that would need to be built in short order to meet contingency loads. In both cases, there is uncertainty for the need and in-service timing for gas; BC Hydro will need to advance the development of gas-fired generation to ensure the contingencies can be met.

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53 The orange and white slashed bar for gas capacity indicates that it may be an aggressive schedule to deliver gas capacity at an earliest in-service date of F2017.
Small Gap Regret/Risk Analysis

If BC Hydro were to plan to a mid-gap and the outcome was a small gap, Figure 6-35 and Table 6-36 demonstrate that the gas strategy (Near-term Outcome 2C) would have a much higher portfolio cost than the bridging strategy (Near-term Outcome 1C).

Figure 6-35   PV Analysis Results: Small Gap
Table 6-36  PV Analysis Results: Small Gap

<table>
<thead>
<tr>
<th>Near-Term Capacity Option</th>
<th>Market Scenario C PV ($ millions)</th>
<th>Market Scenario B PV ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bridging</td>
<td>3,350</td>
<td>2,755</td>
</tr>
<tr>
<td>Gas</td>
<td>5,355</td>
<td>3,974</td>
</tr>
</tbody>
</table>

The green line in Figure 6-36 shows the initial mid gap on which the resource plan was based and the red line shows a near-term small gap outcome. The higher cost of the gas option in this case is driven by the significant amount of stranded gas assets as shown by the surplus capacity above the red load line on the LRB in Figure 6-36.

Figure 6-36  Small Gap Capacity LRB: Gas Option

The results for the high and low bridging scenarios were almost identical; so results have only been shown for the low bridging cost scenario.

BC Hydro’s modelling assumption of an 18 per cent capacity factor from the gas capacity may slightly overstate the cost of the gas option because BCH would likely not run it if the capacity was not required, however the overstatement is likely small given the offset of the cost of gas and carbon taxes by the value of those exports.
Note that if the LNG 3 scenario load were to materialize in the small gap case, the negative impact of stranded gas assets would be reduced by approximately $1 billion under Market Scenario B and by approximately $1.9 billion under Market Scenario.

Figure 6-36 demonstrates the LRB for the bridging strategy under the mid gap (green line) and the surplus capacity that would occur if the small gap were to occur. Although the graph makes it appear that bridging option (in purple) is surplus in the small gap scenario, it has a distinct advantage because of the flexibility of these resources, spending and capacity reliance can be quickly modified or stopped as changes and trends in the gap size emerge.

Figure 6-37 Small Gap Capacity LRB: Bridging Option

![Graph showing small gap capacity LRB for bridging option](image)

Figure 6-38 demonstrates that the comparison of the two near-term strategies involves comparing the two potential outcomes with regrets. One with a higher likelihood, low cost outcome (Near-Term Outcome 1B) that preserves gas optionality.
and one with a much lower likelihood, high cost outcome (Near-Term Outcome 2C) that uses up the gas option.

![BRP Decision Tree and Conclusions](image)

**Figure 6-38** BRP Decision Tree and Conclusions

<table>
<thead>
<tr>
<th>Near Term Capacity Strategy</th>
<th>Near Term Outcome</th>
<th>Relative Likelihood</th>
<th>Conclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Rely on Market backed by CE+BGU</td>
<td>(A) Large Gap</td>
<td>10%</td>
<td>No Regret vs. 2A if Gas can be added in time, Gas Optionality Lost</td>
</tr>
<tr>
<td></td>
<td>(B) Mid Gap</td>
<td>80%</td>
<td>Minimal Regret vs. 2B ($37M - $237M), Gas Optionality Preserved</td>
</tr>
<tr>
<td></td>
<td>(C) Small Gap</td>
<td>10%</td>
<td>No Regret vs. 2C, Gas Optionality Preserved</td>
</tr>
<tr>
<td></td>
<td>(A) Large Gap</td>
<td>10%</td>
<td>No Regret vs. 1A if Gas can be added in time, Gas Optionality Lost</td>
</tr>
<tr>
<td></td>
<td>(B) Mid Gap</td>
<td>80%</td>
<td>No Regret vs. 1B if Gas can be added in time, Gas Optionality Lost</td>
</tr>
<tr>
<td></td>
<td>(C) Small Gap</td>
<td>10%</td>
<td>Regret vs. 1C ($1.2B - $2B), Gas Optionality Lost</td>
</tr>
</tbody>
</table>

BC Hydro concluded that relying on market, CE and Burrard is a flexible and cost-effective capacity option to respond to near-term deficits or surpluses given BC Hydro’s preference to preserve the option value of gas for addressing future transmission alternatives. In addition, the regret analysis highlights the need to continue to advance gas-fired projects as further discussed in the next section.

### 6.10.5.4 Long-Term Capacity Needs

**Figure 6-29** demonstrates that over 1,000 MW of new capacity could be required in the next 20 years after accounting for DSM Option 3, Site C, the capacity from 2,000 GWh of IPP acquisitions and Revelstoke Unit 6. Given the large inventory of pumped storage resources and the 93 per cent clean energy objective BC Hydro is recommending to further explore this resource to develop an understanding of where and how to site such resources in the province to potentially serve long-term capacity requirements. To backstop this uncertain resource, BC Hydro will need to preserve gas capacity as a reliable alternative if pumped storage does not materialize. In addition, BC Hydro will continue to recognize the value of capacity
rich resources like geothermal and biomass facilities into future acquisition processes. Lastly, BC Hydro is recommending the investigation of additional Resource Smart projects and the pursuit of DSM capacity options as potential cost effective ways to meet expected capacity shortfalls.

6.10.6 Contingency Planning

Contingency plans identify the need for additional resources that need to be available should the BRP conditions not materialize as expected. The resulting actions seek to prepare to meet even greater demand and reduce the lead time for contingency resources to be in service if the need arises. If the advanced in-service dates are not planned for and maintained, the contingency will be ineffectual.

In developing contingency plans, BC Hydro considers both capacity and energy shortfall risks; however, as described in section 6.10.1, meeting capacity requirements is BC Hydro’s primary concern. The capacity concern includes both generating capacity and transmission capacity. As discussed in section 6.10.1, BC Hydro prepares specific CRPs that are used in the analysis of associated transmission requirements. The CRPs are described further in Chapter 9.

Table 6-34 in section 6.10.4 identified the following three key uncertainties in which BC Hydro may have inadequate reaction time that would drive the preparation of contingency plans and the need for capacity:

- Load forecast uncertainty;
- DSM deliverability risk; and
- Intermittent resource effective load carrying capability.

6.10.6.1 Load Forecast Uncertainty and DSM Deliverability Risk

As discussed in section 5.2.3.3, BC Hydro develops a BRP in reference to the most likely load after DSM or mid-gap, but must be prepared in case this gap is larger than expected in the future.
Figure 6-39 examines the degree to which BC Hydro could be surprised by a larger or smaller gap than expected for the five DSM options. In particular, it assumes that F2020 is the earliest time by which BC Hydro would be able to acquire new supply after discovering a substantial deviation from the mid-gap after the next four years.

As Figure 6-39 highlights, in F2020 there is a substantial amount of uncertainty around the forecasted size of the gap (+/- 1,200 MW with DSM Option 3). This underscores the importance of having adequate capacity resources ready in the near-term to respond in case demand drifts away from its expected level in the coming years. Table 6-32 lists out such resources and their lead times.

6.10.6.2 Wind Effective Load Carrying Capability and IPP Attrition Uncertainty

As discussed in section 5.2, BC Hydro considers additional uncertainty with respect to the reliance on wind effective load carrying capability and the potential for increased IPP attrition.
Chapter 6 - Resource Planning Analysis

Wind ELCC Uncertainty

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

Additional uncertainty analysis on the size of the gap reflecting the probability distributions for load, DSM deliverability, wind ELCC uncertainty and IPP attrition indicated that the range in gap uncertainty shown in Figure 6-39 was adequate for planning purposes; however, the intermittent resources and IPP attrition are a risk that BC Hydro will need to continue to monitor.

6.10.6.3 Incremental Load Scenarios for the LNG, Mining and Oil & Gas Sectors

As discussed in Chapter 2, BC Hydro considers the additional capacity requirements that come with potential future loads in the North Coast and Fort Nelson Regions. Figure 6-40 demonstrates the potential capacity shortfalls that BC Hydro could face if loads in these regions materialize.
6.10.7 Conclusions

The capacity and contingency analysis has shown the following:

- Site C’s capacity is required as BC Hydro has limited clean capacity resource options;
- Revelstoke Unit 6 is BC Hydro’s lowest cost capacity resource with ancillary benefits and should be advanced;

Given the potential significant requirements in the near term (up to 2,000 MW) and the long term (up to 3,000 MW), BC Hydro will need to continue to advance gas and pumped storage and continue to build an inventory of other capacity resources to ensure that these resources can be quickly built in the case the need arises.
Combined, Site C and Revelstoke Unit 6 meet BC Hydro’s mid-forecast capacity requirements in F2022, however, there is a short to mid-term gap that needs to be filled;

Following Revelstoke Unit 6, gas-fired generation is a certain capacity resource that is both cost effective and is expected to have the shortest time to develop. There are siting and approval risks with gas-fired generation;

The short to mid-term capacity gap is best filled with bridging resources of market, CE and, if needed, Burrard since they are minimal up front cost that perform well under uncertain future needs;

However, in a contingency world, it is demonstrated that additional gas-fired resources may be needed and these resources should be advanced. Current considerations for location of gas fired generation are in the North Coast, Kelly Lake, Vancouver Island and Fort Nelson;

In the longer term, BC Hydro needs to prove out additional capacity resources:

- Some of these resources may be available in the shorter term and reduce the bridging resource requirements – these resources include DSM capacity programs, voluntary load curtailment, and resource smart projects;
- Pumped storage needs to be investigated to make it an option that can be relied upon in the future.

Conclusions in this Capacity and Contingency section support Recommended Actions Nos. 3, 5, 6, 7, 10 and 13 as described in Chapter 9.