Chapter 2

Load and Resource Gap
# Table of Contents

2.1 Introduction .................................................................................................................. 2-1  
2.2 BC Hydro’s 2011 Load Forecast .................................................................................. 2-1  
  2.2.1 Load Forecast Methodology Overview ................................................................. 2-2  
  2.2.2 Energy Load Forecast – Key Trends .................................................................. 2-4  
     2.2.2.1 Incremental Load Scenarios for the LNG, Mining and Oil & Gas Sectors .... 2-8  
  2.2.3 Peak Demand Load Forecast – Key Trends ......................................................... 2-9  
  2.2.4 Load Forecast Uncertainties ............................................................................. 2-10  
  2.2.5 DSM/Load Forecast Integration ......................................................................... 2-12  
2.3 Existing, Committed and Planned Resources ............................................................. 2-13  
  2.3.1 Heritage Hydro ..................................................................................................... 2-14  
     2.3.1.1 CEA Self-Sufficiency Requirements ............................................................ 2-15  
     2.3.1.2 Average Water Heritage Hydro Energy Assessment .................................. 2-16  
     2.3.1.3 Impacts of Planning to Average Water on BC Hydro Operations ............. 2-19  
     2.3.1.4 Columbia River Treaty ............................................................................... 2-20  
     2.3.1.5 Resource Smart Projects (Including Ruskin and John Hart) ....................... 2-21  
     2.3.1.6 Waneta Transaction .................................................................................. 2-21  
     2.3.1.7 Assessment of Climate Change Impacts ...................................................... 2-22  
  2.3.2 Heritage Thermal .................................................................................................. 2-22  
     2.3.2.1 Burrard Thermal ..................................................................................... 2-23  
     2.3.2.2 Prince Rupert Generating Station .............................................................. 2-23  
  2.3.3 Existing, Committed and Planned IPP Supply ....................................................... 2-23  
     2.3.3.1 Pre-Bioenergy Call Phase 1 Resources ....................................................... 2-24  
     2.3.3.2 Bioenergy Call – Phases 1 and 2 ................................................................ 2-24  
     2.3.3.3 Clean Power Call .................................................................................... 2-25  
     2.3.3.4 Integrated Power Offer ............................................................................ 2-25  
     2.3.3.5 AltaGas Projects – Northwest Transmission Line ...................................... 2-25  
     2.3.3.6 Waneta Expansion .................................................................................... 2-25  
     2.3.3.7 Standing Offer Program .......................................................................... 2-26  
     2.3.3.8 Distributed Generation and Net Metering ................................................. 2-26  
     2.3.3.9 EPA Renewal Assumptions for IPP Resources ......................................... 2-26  
  2.3.4 ELCC from Existing, Committed and Planned Resources ..................................... 2-27
2.3.5 Energy from Existing, Committed and Planned Resources ....2-29

2.4 Load/Resource Balance.................................................................................2-30
2.4.1 BC Hydro’s LRB..................................................................................2-30

2.5 Regional Load Scenarios...........................................................................2-33
2.5.1 North Coast LNG and Mining Load Scenarios ..................................2-34
2.5.2 Fort Nelson Integration and Horn River Basin Electrification ..........2-38
  2.5.2.1 Fort Nelson................................................................................2-40
  2.5.2.2 Horn River Basin......................................................................2-42
2.5.3 Coastal Region (Lower Mainland/Vancouver Island) ...................2-44
2.5.4 Vancouver Island..............................................................................2-45
2.5.5 South Peace Region..........................................................................2-46

List of Figures

Figure 2-1 2011 Energy Mid Load Forecast (before DSM)...............2-5
Figure 2-2 2011 Peak Demand Mid Load Forecast (before DSM) ....2-10
Figure 2-3 2011 Energy Mid Load Forecast (without Initial LNG)......2-11
Figure 2-4 2011 Peak Demand Load Forecast without Initial LNG ....2-12
Figure 2-5 Frequency Distribution of Heritage Hydro Generation ....2-19
Figure 2-6 Energy Load/Resource Balance ..............................................2-31
Figure 2-7 Capacity Load/Resource Balance ..........................................2-32
Figure 2-8 Energy Load/Resource Balance with LNG3 and High Mining Load Scenarios ........................................2-34
Figure 2-9 Capacity Load/Resource Balance with LNG3 and High Mining ..............................................................................2-35
Figure 2-10 North Coast Transmission System ..................................2-36
Figure 2-11 North Coast Load/Resource Balance .................................2-37
Figure 2-12 Northwest Transmission Line...............................................2-38
Figure 2-13 Energy Load/Resource Balance with Fort Nelson and Horn River Basin..........................................................2-39
Figure 2-14 Capacity Load/Resource Balance with Fort Nelson and Horn River Basin..........................................................2-40
Figure 2-15 Fort Nelson Area Load/Resource Balance ..........................2-42
Figure 2-16 Fort Nelson/HRB Regional Load/Resource Balance........2-43
Figure 2-17 Coastal (LM+VI) Load/Resource Balance.........................2-45
Figure 2-18 Vancouver Island Load/Resource Balance .......................2-46
Figure 2-19 South Peace Region and DCAT Project ...............................2-47
Figure 2-20 Dawson Creek Load/Resource Balance ...............................2-48
List of Tables

<table>
<thead>
<tr>
<th>Table</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>2-1</td>
<td>Energy Mid Load Forecast (before DSM)</td>
<td>2-3</td>
</tr>
<tr>
<td>2-2</td>
<td>Peak Demand Mid Load Forecast (before DSM)</td>
<td>2-3</td>
</tr>
<tr>
<td>2-3</td>
<td>Sector Breakdown of Energy Mid Load Forecast (before DSM, without losses)</td>
<td>2-5</td>
</tr>
<tr>
<td>2-4</td>
<td>Firm Energy and ELCC from Expiring EPAs</td>
<td>2-27</td>
</tr>
<tr>
<td>2-5</td>
<td>ELCC in F2017</td>
<td>2-28</td>
</tr>
<tr>
<td>2-6</td>
<td>Firm Energy Capability in F2017</td>
<td>2-29</td>
</tr>
<tr>
<td>2-7</td>
<td>Energy Surplus/Deficit (GWh)</td>
<td>2-31</td>
</tr>
<tr>
<td>2-8</td>
<td>Capacity Surplus/Deficit (MW)</td>
<td>2-32</td>
</tr>
<tr>
<td>2-9</td>
<td>Energy Surplus/Deficit with LNG3 and High Mining Load Scenarios (GWh)</td>
<td>2-35</td>
</tr>
<tr>
<td>2-10</td>
<td>Capacity Surplus/Deficit with LNG3 and High Mining (MW)</td>
<td>2-35</td>
</tr>
<tr>
<td>2-11</td>
<td>Energy Surplus/Deficit with Fort Nelson and Horn River Basin Load Scenario (GWh)</td>
<td>2-39</td>
</tr>
<tr>
<td>2-12</td>
<td>Capacity Surplus/Deficit with Fort Nelson and Horn River Basin (MW)</td>
<td>2-40</td>
</tr>
</tbody>
</table>
2.1 Introduction

The first step in the Integrated Resource Plan (IRP) process is to determine the gap between existing resources and customers’ forecast load requirements. The Load/Resource Balance (LRB) establishes the need for incremental demand-side, supply-side and transmission resources by comparing the 2011 Load Forecast to existing, committed and planned resources. This chapter consists of the following sections: section 2.2 reviews the 2011 Load Forecast; section 2.3 examines the existing, committed and planned resources in the context of BC Hydro’s planning criteria, the Clean Energy Act (CEA) and the 2007 BC Energy Plan; section 2.4 presents the integrated system LRB; and section 2.5 reviews regional planning issues and constraints in five regions, namely the North Coast, Fort Nelson/Horn River Basin, Coastal (Lower Mainland/Vancouver Island), Vancouver Island and South Peace.

BC Hydro has summarized some load forecasts and LRBs in this chapter with respect to key milestone years: F2017 (self-sufficiency target year); F2021 (Demand-Side Measures (DSM) target year and Site C earliest in-service date); F2026; and F2031 (final year of the planning horizon). All values shown include losses\(^1\), unless otherwise stated.

2.2 BC Hydro’s 2011 Load Forecast

This section presents BC Hydro’s 2011 Load Forecast\(^2\) of energy and peak demand requirements for the integrated system (unless otherwise indicated). The 2011 Load Forecast presented in this section reflects the impact of savings from energy efficiency and conservation initiatives achieved through F2011, but does not include future targeted savings in F2012 and beyond.

BC Hydro prepares a high, mid and low Load Forecast using a Monte Carlo probabilistic assessment. The values discussed in this chapter reflect BC Hydro’s

\(^1\) Transmission and distribution losses.

\(^2\) The 2011 Load Forecast document is contained in Appendix 2A.
mid Load Forecast, which includes two liquefied natural gas (LNG) facilities: the Douglas Channel LNG facility and the significantly larger Kitimat LNG facility. These two initial LNG projects will subsequently be referred to as ‘Initial LNG’. BC Hydro has prepared two mid Load Forecasts in the 2011 Load Forecast – a mid Load Forecast with Initial LNG and a mid Load Forecast without Initial LNG. The Initial LNG facilities are included as part of the mid Load Forecast, as they have obtained material government agency approvals, such as Environmental Assessment approvals and National Energy Board export licenses, and have requested service from BC Hydro. In addition to the mid Load Forecast, incremental load scenarios have been identified that include:

- General high and low load growth. For information on how high load growth and low load growth contribute to large and small load/resource gap scenarios respectively, please see the discussion in Chapter 5;
- New loads emerging in the North Coast, such as the construction of a third LNG facility (LNG3) and the prospect of high mining loads; and
- The integration of the Fort Nelson region and electrification of the Horn River Basin oil and gas loads.

2.2.1 Load Forecast Methodology Overview

BC Hydro’s load forecast is produced on an annual basis and is a key input in determining the LRB. BC Hydro’s load forecasting methodology has been the subject of extensive review in a number of British Columbia Utilities Commission (BCUC) regulatory proceedings, including the 2006 Integrated Energy Plan (IEP)/Long Term Acquisition Plan (LTAP), the 2008 LTAP and the 2011 Ruskin Certificate of Public Convenience and Necessity (CPCN) application. In its 2008 LTAP Decision, the BCUC accepted BC Hydro’s load forecast methodology and a similar methodology has been adopted in the IRP.

3 The mid load forecast is also referred to as the reference or expected load forecast.
BC Hydro considers the size and likelihood of loads and demand trends when preparing its load forecast. Potentially large loads, such as LNG, have been considered as binary loads\(^4\) in the 2011 Load Forecast that underpins this IRP. BC Hydro is closely monitoring industry and technological trends with respect to future electrification loads, which could lead to the possible inclusion of such loads in future mid load forecasts. Similarly, BC Hydro includes verifiable information regarding specific customer loads in its load forecast to reflect possible load reductions due to customer attrition.

Table 2-1 and Table 2-2 present the 2011 Load Forecast energy and peak demand requirements before DSM, both without and with the Initial LNG load.

### Table 2-1  
**Energy Mid Load Forecast (before DSM)**

<table>
<thead>
<tr>
<th></th>
<th>(GWh)</th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
<th>Average Annual Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>10-Year F2012-F2021 (%)</td>
</tr>
<tr>
<td>Mid Load Forecast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2.7</td>
</tr>
<tr>
<td>without Initial LNG</td>
<td>67,457</td>
<td>72,476</td>
<td>75,544</td>
<td>82,075</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial LNG</td>
<td>3,800</td>
<td>5,281</td>
<td>5,281</td>
<td>5,281</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Load Forecast</td>
<td>71,258</td>
<td>77,757</td>
<td>80,825</td>
<td>87,356</td>
<td></td>
<td>3.5</td>
</tr>
<tr>
<td>with Initial LNG</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 2-2  
**Peak Demand Mid Load Forecast (before DSM)**

<table>
<thead>
<tr>
<th></th>
<th>(MW)</th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
<th>Average Annual Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>10-Year F2012-21 (%)</td>
</tr>
<tr>
<td>Mid Load Forecast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2.3</td>
</tr>
<tr>
<td>without Initial LNG</td>
<td>12,389</td>
<td>13,053</td>
<td>13,891</td>
<td>14,945</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial LNG</td>
<td>680</td>
<td>680</td>
<td>680</td>
<td>680</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Load Forecast</td>
<td>13,070</td>
<td>13,733</td>
<td>14,571</td>
<td>15,625</td>
<td></td>
<td>2.9</td>
</tr>
<tr>
<td>with Initial LNG</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^4\) The term “binary loads” is used to refer to large, single point loads that will either be developed or not, and so, are not conducive to a probabilistic assessment.
The 2011 Load Forecast methodology is similar to that used for the 2008 Load Forecast, with the following major differences:

- A portion of the industrial distribution sector (industrial loads such as sawmills served at distribution voltages) is now forecast on a sub-sector basis (i.e., mining, oil and gas, wood) versus the previous use of a regression analysis for the entire sector. The application of customer and sector-specific information is expected to improve the regional and total system load projections by incorporating load drivers such as the provincial pine beetle infestation and specific industrial sector expansions.

- Electric vehicle (EV) loads are included in the 2011 Load Forecast. EV load impacts are forecast to be minimal in the first 10 years, resulting in an increase of only 38 GWh/year in F2017, rising to 2,120 GWh/year by F2031. (A discussion of general electrification is provided in Chapter 6, including potential incremental load scenarios.)

- In the 2008 LTAP Decision, the issue of potential double-counting of DSM in the forecasting models was identified and the BCUC directed BC Hydro to address this in its next LTAP.\(^5\) In a November 2010 letter to the BCUC addressing the directives from the 2008 LTAP Decision, BC Hydro indicated that the IRP is one of the venues in which DSM/Load Forecast Integration will be addressed. BC Hydro reviewed the potential areas of overlapping DSM savings in its load forecast and concluded that the codes and standards contained in the 20-year DSM Plan resulted in a degree of double-counting. This modification to the 2011 Load Forecast is further detailed in section 2.2.5.

2.2.2 Energy Load Forecast – Key Trends

The 2011 Load Forecast was affected by two major events: (a) the ongoing persistence of the recession and credit crisis and (b) shale gas developments in North America. The breakdown of BC Hydro’s energy mid Load Forecast by sector

and for the total integrated system is contained in Table 2-3 and is graphically depicted in Figure 2-1. The drop in F2026 is due to the scheduled closure of a major mine.

### Table 2-3 Sector Breakdown of Energy Mid Load Forecast (before DSM, without losses)

<table>
<thead>
<tr>
<th>Energy Load (GWh/year)</th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
<th>10-Year F2012-F2021 (%)</th>
<th>20-Year F2012-F2031 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>20,089</td>
<td>21,766</td>
<td>24,080</td>
<td>26,613</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>Commercial</td>
<td>18,196</td>
<td>19,714</td>
<td>21,267</td>
<td>23,544</td>
<td>2.4</td>
<td>2.1</td>
</tr>
<tr>
<td>Industrial (without Initial LNG)</td>
<td>21,686</td>
<td>23,037</td>
<td>21,832</td>
<td>22,891</td>
<td>3.8</td>
<td>1.8</td>
</tr>
<tr>
<td>Initial LNG</td>
<td>3,552</td>
<td>4,935</td>
<td>4,935</td>
<td>4,935</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Westminster/FortisBC Contractual Sales</td>
<td>1,536</td>
<td>1,559</td>
<td>1,598</td>
<td>1,636</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Domestic Sales</td>
<td>65,058</td>
<td>71,011</td>
<td>73,712</td>
<td>79,619</td>
<td>3.6</td>
<td>2.3</td>
</tr>
</tbody>
</table>

### Figure 2-1 2011 Energy Mid Load Forecast (before DSM)
Chapter 2 - Load and Resource Gap

Residential:

The drivers of the residential forecast are the use per account times the number of accounts. The number of accounts is forecast to be lower than in previous load forecasts due to lower housing start projections. Residential electricity sales were relatively flat on a weather-adjusted basis between F2010 and F2011; therefore, the starting point of the 2011 Load Forecast is lower than that of the previous forecast. The growth in population is somewhat higher, while personal income remains relatively stable.

In the long term, use per account is expected to be relatively flat, based on a number of off-setting factors.6

Commercial:

The electricity consumption of the commercial sector can vary considerably from year to year, reflecting the level of activity in B.C.’s service sector. The forecast drivers include commercial end-use efficiencies and projections of retail sales, employment and commercial output. The forecast is higher in the medium to long term due to lower end-use equipment efficiency projections from the Energy Information Administration in the U.S. Heating and cooling efficiencies show the largest change, while “other” end-use efficiencies are somewhat improved.

Industrial:

BC Hydro prepares its industrial load forecast on a customer-by-customer basis, considering the sector-specific issues that each customer faces. The largest industrial sectors affecting electricity demand in B.C. are LNG, forestry, oil and gas, and mining. Demand from these sectors is challenging to forecast due to load volatility and sensitivity to factors, such as unpredictable commodity prices.

---

6 For example, housing sizes are generally increasing, but there is also movement towards ‘downsizing’ to smaller dwellings (e.g., condominiums or townhouses). Similarly, the demand for electronic, entertainment, and telecommunication devices in the home is increasing; however, improvements in the energy efficiency of these devices are being made.
economic cycles, pine beetle infestations, regulatory approvals and labour disputes. Electricity consumption is driven substantially by commodity markets and economic conditions in the U.S., China and Japan. The key changes to the load forecast for the industrial sector include the following:

- Liquefied Natural Gas – new LNG facilities potentially represent the biggest additional loads on BC Hydro’s system. The 2011 Load Forecast factors in additional demand from Initial LNG, on the B.C. North Coast. The Initial LNG load is expected to require about 4,935 GWh/year of energy for refrigeration and gas compression. After reflecting transmission losses, the Initial LNG load is about 5,281 GWh/year and 680 MW.

- Pulp and Paper – reductions in mechanical pulp and related paper production loads are expected due to revised production estimates for larger mills. Digital media substitution is a key driver.

- Oil & Gas – drivers include deferred drilling and gas processing due to current low gas prices, preferential drilling for higher value oil and natural gas liquids, constraints in northeastern B.C. gas processing capabilities, and the performance of new shale gas wells being better than anticipated.

- Mining – the load has been adjusted substantially upward largely due to favourable metal prices, which have led to announced expansions of existing mines and deferrals of planned mine shutdowns. High copper and gold prices are driving mining investment and activity levels not seen in B.C. for many years. In the short term, the 2011 mining forecast has a lower starting point relative to previous years, because mining sales in F2012 are forecast to be slightly lower due to the revised timing of mine start-ups and expansions. Mining loads are forecasted to be up in the medium term, primarily as due to several mines extending pre-announced shutdown dates, e.g., Huckleberry and Highland Valley Copper.
• Industrial General – is primarily made up of manufacturing, wood processing, mining and agriculture, served at distribution voltages. Sales expectations for the wood sector have been reduced in the short term. U.S. housing starts, which suffered a considerable drop since the 2008 Load Forecast, have not recovered as expected. In the long term, oil and gas sales are higher than in previous load forecasts.

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

BC Hydro has constructed scenarios to examine the potentially large new loads that could emerge due to LNG, mining in the North Coast, and oil and gas in northeastern B.C. The analysis of how BC Hydro could meet these loads, should they emerge, is contained in Chapter 6. While too uncertain to be included in the mid Load Forecast, these potential loads warrant scenario analysis due to the long lead time required to provide electricity to these customers if they seek service from BC Hydro. A description of these scenarios follows:

• For the LNG sector, BC Hydro has constructed a scenario reflecting an additional large new LNG project, LNG3, of approximately 24 million tonnes per year of LNG output, constructed in several phases between F2020 and F2026. If the proponent chooses grid supply for all phases of the project, the electricity requirements could be 1,200 MW and 10,000 GWh/year. The project would also require a new gas pipeline, which could use either natural gas or electricity for compression. The scenario assumes that the pipeline compression energy requirements are primarily met with grid supply, which after reflecting transmission losses, results in a total electricity requirement of approximately 1,700 MW and 12,800 GWh/year.

• For the mining sector, BC Hydro has constructed a scenario that examines higher mining load in the North Coast region, in addition to LNG3. While the full potential of the mining loads interconnecting to BC Hydro’s committed
Northwest Transmission Line (NTL)\(^7\), which comes into service in F2015, far exceeds the estimated 465 MW capacity of the line, the mining loads have been capped at the estimated capacity of the line. The mid Load Forecast includes approximately 200 MW of load in the NTL region, which is the probability weighted sum of the forecasted mining loads in this region. This load is forecasted to be approximately 70 GWh/year and 20 MW in F2014 growing to approximately 2,000 GWh/year and 270 MW by F2018.

- For the oil and gas sector, BC Hydro has constructed scenarios that examine the Horn River Basin (HRB) shale gas play, a potentially large load north of Fort Nelson that could require electricity service from BC Hydro for gas extraction and transport. Serving this load with new transmission through the potential integration of the Fort Nelson load may be an option for this area that is facing potentially significant demand growth from the oil and gas sector. Transformative technologies have made shale gas plays in northeastern B.C. economically viable. The HRB is an immense resource whose viability will be significantly improved if its natural gas production is used to supply LNG exports. These scenarios explore the electrification of a significant share of the work energy required to bring this gas to market, with the electricity being provided through a connection to the integrated BC Hydro grid from the Peace River region through Fort Nelson.

The incremental energy and peak loads of each of the load scenarios are shown in section \(2.5\).

### 2.2.3 Peak Demand Load Forecast – Key Trends

The peak demand Load Forecast generally follows the trends in the energy Load Forecast. In the near term, the distribution peak demand forecast is reduced with a lower accounts projection. In addition, near-term oil and gas and wood sector sales forecasts are lower. Therefore, the overall distribution peak demand forecast is lower

\(^7\) For more details on NTL please refer to section \(2.5.1\).
relative to the previous forecast. In the medium term, the transmission peak demand forecast is above last year, due to mine closure deferrals, consistent with energy forecast trends. In the long term, the peak demand forecast is lower than the previous forecast.

Figure 2-2 shows the peak demand Load Forecast before DSM, and including projected rate level impacts. Peak demand is expected to grow by an average annual rate of 2.3 per cent from F2012 to F2021 and 1.8 per cent from F2012 to F2031. With the inclusion of the potential Initial LNG load, the forecast peak demand average annual growth rate is 2.9 per cent from F2012 to F2021 and 2.0 per cent from F2012 to F2031.

Figure 2-2  2011 Peak Demand Mid Load Forecast (before DSM)

2.2.4 Load Forecast Uncertainties

As discussed above, BC Hydro uses a Monte Carlo model to estimate the uncertainty of BC Hydro’s load forecast for the integrated system in general (not
including large LNG loads, such as Initial LNG\(^8\)). Details on the Monte Carlo model are included in the 2011 Load Forecast document (Appendix 2A). This model produces a forecast uncertainty band around the mid Load Forecast by examining the impact on load of the uncertainty associated with a set of key drivers, including economic activity, weather, electricity rates and elasticities. The uncertainty bands include:

- A low band, which shows the expected outcome if the load is less than the twentieth percentile in each year.

- A high band, which shows the expected outcome if the load exceeds the eightieth percentile in each year.

**Figure 2-3** and **Figure 2-4** show the 2011 mid Load Forecast and the high and low uncertainty band forecasts before DSM and including future rate level changes. The drop in F2026 is due to the scheduled closure of a major mine.

---

\(^8\) Large single loads are not included as they do not lend themselves to a probabilistic assessment.
2.2.5 DSM/Load Forecast Integration

The interrelationship between load growth and DSM savings was discussed during the 2008 LTAP proceeding. As directed in the BCUC’s 2008 LTAP Directive 6, BC Hydro continued work examining the integration of DSM and the load forecast.

One area identified in this investigation as having the potential for double-counting of DSM was the load forecasting models. BC Hydro’s models incorporate embedded baseline efficiency levels as provided by the U.S. Energy Information Administration (EIA), which are specific to each major type of residential and commercial end use. BC Hydro, in constructing its after-DSM load forecast, subtracts DSM savings enabled by B.C.-based codes and standards, where the assumed baseline efficiencies may actually be lower than that used by the EIA. This is the essence of the identified double-counting issue.

BC Hydro reviewed the codes and standards contained in its 20-year DSM Plan against the EIA documentation and identified which individual codes and standards result in potential double-counting. Based on this analysis, the upwards load adjustments for DSM double-counting in the 2011 Load Forecast are approximately
270 GWh/year in F2017 and about 750 GWh/year by the end of the 20-year forecast horizon.

Further details regarding the DSM/Load Forecast Integration, including areas identified for further analysis, are captured in Appendix 2B of this IRP.

2.3 Existing, Committed and Planned Resources

The other major input to the LRB for the IRP analysis is the existing, committed and planned supply resources that serve the integrated system. Definitions of these three categories of resources follow:

- Existing resources include BC Hydro’s Heritage hydroelectric and thermal resources, as well as Independent Power Producer (IPP) facilities delivering electricity to BC Hydro.

- Committed resources are those resources for which material regulatory approvals have been secured (BCUC, either secured or through exemption; and environmental assessment related, if required, and for which the BC Hydro Board of Directors has authorized implementation.

- Planned resources are those resources that BC Hydro is currently pursuing, e.g., resources for which material regulatory approvals have been secured, but the BC Hydro Board has not yet authorized implementation or resources for which the BC Hydro Board has authorized implementation, but regulatory approvals have not yet been secured.

Recent committed resources include the firm energy contribution from the Bioenergy Phase 2 Call projects, Waneta Expansion project, Mica Units 5 and 6, the Ruskin Dam and Powerhouse Upgrade Project (Ruskin Upgrade Project) and the energy supply contract in respect of the Conifex power project. Recent planned resources include the John Hart Generating Station Replacement Project (John Hart Replacement Project) and several CEA-exempted BC Hydro power acquisitions processes, namely the Standing Offer Program and Integrated Power Offer.
BC Hydro mainly relies on the firm energy load carrying capability (FELCC) and effective load carrying capability (ELCC) in the LRB. The FELCC is defined as the maximum amount of annual energy (GWh/year) that a hydroelectric system can produce under critical water conditions, where critical water conditions are the most adverse sequence of stream flows occurring within the historical record. ELCC is the maximum peak load (MW) that a generating unit or system of units can reliably supply, such that the Loss of Load Expectation will be no greater than one day in ten years. For additional details on the FELCC and ELCC assessment of resources please refer to Appendix 3C. The following sections provide further information on the supply resources included in the LRB.

2.3.1 Heritage Hydro

As set out in subsection 6(1) of the CEA and the Electricity Self-Sufficiency Regulation, BC Hydro must rely on the average energy capability of its Heritage hydroelectric assets for the purposes of determining its ability to meet the energy requirements of customers (i.e., in the LRB). Average energy capability is calculated based upon the maximum amount of annual energy that the Heritage hydroelectric assets can produce under average water conditions. In F2017, this amounts to approximately 48,400 GWh/year, including contributions from BC Hydro’s existing Heritage hydro assets, Resource Smart upgrades to existing BC Hydro facilities and the Waneta Transaction.

---

9 Dependable capacity is also used to describe the capacity contributions of non-intermittent resources. For convenience, capacity contributions of all resources are referred to as ELCC.
10 The term “average water conditions” is defined in section 1 of the Electricity Self Sufficiency Regulation pursuant to the CEA to mean “the average stream flows occurring within BC Hydro’s historical record”.
11 Only those committed Resource Smart upgrades that do not require material regulatory approvals, such as G.M. Shrum turbine upgrades. Planned Resource Smart projects at Ruskin and John Hart are included as additional items.
12 The Resource Smart and Waneta Transaction energy and capacity values are not included in the ‘Heritage Hydro’ values shown in the supply stack and are shown as incremental supply contributions. More detail on these volumes is provided in sections 2.3.1.5 and 2.3.1.6 of the IRP.
13 The 48,200 GWh/year of average energy capability referenced in Special Direction No. 10 to the BCUC is calculated by subtracting the committed Resource Smart upgrades including Mica Units 5 and 6 from the F2017 value of 48,400 GWh/year.
BC Hydro’s FELCC is approximately 44,300 GWh/year in F2017. The difference between the Heritage hydro average energy capability and FELCC is 4,100 GWh/year, which is the average non-firm energy capability of the Heritage hydro resources. Relying on this 4,100 GWh/year means that, on an operational basis, if Heritage hydro water conditions are lower than average, IPP non-firm energy/market purchases may be required to replace non-firm Heritage hydro.

The ELCC of the Heritage hydro resources is 10,500 MW in F2015, including contributions from BC Hydro’s existing Heritage hydro assets, Resource Smart upgrades to existing BC Hydro facilities and the Waneta Transaction.

2.3.1.1 CEA Self-Sufficiency Requirements

Pursuant to section 6 of the CEA, BC Hydro is required to achieve electricity self-sufficiency by the year 2016 (i.e., F2017), by holding the rights to an amount of electricity that meets its electricity supply obligations, taking into account DSM and electricity solely from electricity generating facilities within the Province. As discussed above, to support this determination, the Heritage energy capability is defined in the Electricity Self-Sufficiency Regulation, B.C. Reg. 315/2010 (as amended by OIC 036, dated February 2, 2012) as the capability under average water conditions.

As a result of the requirements and intentions set out above:

- The 3,000 GWh/year of additional energy, as “insurance”, is no longer included in the updated LRBs;

- The Canadian Entitlement (CE) is the Canadian portion of the additional electricity produced in the Columbia River in the western U.S., as a result of provisions of the Columbia River Treaty (Treaty) of 1961, ratified in 1964. It has not been included in the IRP LRBs, other than as a contingency or potential short-term bridging resource, because it is not generated “solely from electricity

---

14 On February 3, 2012, the B.C. Government indicated its intention to repeal the CEA insurance requirement and has tabled Bill 30 – 2012, which includes the removal of the insurance requirement.
facilities within the Province”. This is consistent with the BCUC’s Decision on Revelstoke Unit 5, where the BCUC agreed that “… the Canadian Entitlement is not a suitable source of dependable capacity in the long-term;”\(^{15}\);

- Under average water conditions, the historic 2,500 GWh/year of Heritage non-firm energy/market allowance becomes 4,100 GWh/year in F2015 and beyond; and

- The 400 MW of market reliance has been removed from the capacity LRBs after F2015, as the 400 MW relies on external markets and is not generated “solely from electricity facilities within the Province”. Reliance on the market and CE for capacity is possible for IRP contingency planning purposes or as a potential short-term bridging resource.

### 2.3.1.2 Average Water Heritage Hydro Energy Assessment

As a predominately hydro system with natural limits to its fuel supply (i.e., water), and according to good utility practice, BC Hydro presents its average water energy capability in the LRB by showing separately the degree of reliance upon the FELCC and the non-firm energy from Heritage hydro resources. By planning to rely upon some volume of non-firm Heritage hydro energy\(^{16}\) supported by the market, BC Hydro will need to continue to assess the markets to ensure that this reliance will result in adequate, cost-effective supply for customers. The degree of reliance upon non-firm Heritage hydro energy backed by the market is termed B.C. Hydro’s non-firm/market allowance (about 4,100 GWh/year in F2017).

The studies for assessing the firm and average energy capabilities are the critical period and long-term system capability studies respectively. Both studies include generation contributions from BC Hydro’s Heritage facilities (hydroelectric and thermal), IPPs and other contractual arrangements that BC Hydro can depend on to meet the load under various water conditions. These conditions are contained in the

---

\(^{15}\) BCUC Decision on Revelstoke Unit 5 CPCN dated July 12, 2007.

\(^{16}\) Non-firm Heritage hydro energy is any energy that is produced by the system in excess of that available during critical water conditions.
available\(^{17}\) 60-year historic record from October 1940 through September 2000, which is assumed to be representative of the range of inflows that may occur in the future. The energy coming from the Heritage hydro resources under critical water conditions is determined to be the Heritage hydro system FELCC, and the average annual energy coming from the Heritage hydro resources over the 60-year record is determined to be the average Heritage hydro system capability under the range of water conditions.

Average water capability can and does change over time with load shape changes, resource addition(s) or retirement(s), Columbia Treaty or other operational changes, and inflow updates. In addition, on an operational basis BC Hydro facilities are coordinated to achieve system objectives, such as maximizing the value of water stored in BC Hydro reservoirs and trade revenue. The amount of energy and resource types of the IPP projects that BC Hydro acquires for customers impacts the dispatch of the Heritage hydro system, and hence, the FELCC and average annual energy results.

**Recent Update to Heritage Hydro FELCC and Average Annual Energy**

In November 2003, through the *BC Hydro Public Power and Legacy and Heritage Contract Act*, the B.C. Government created a “Heritage Contract” to preserve the benefits of the existing hydroelectric and thermal resources for BC Hydro’s customers. BC Hydro estimated that the FELCC of the Heritage hydro resources under critical water conditions was approximately 42,600 GWh/year. This number was re-enforced in Special Direction No. 10 (issued in June 2007) and has been used in the 2004 IEP, the 2006 IEP and the 2008 LTAP.

Since 2003, the BC Hydro system has undergone some major changes. BC Hydro has undertaken studies to update both FELCC and average annual energy. The studies have estimated that the Heritage hydro system FELCC is about

\(^{17}\) The 10-year historic record from October 2000 to September 2010 was not available at the time of the FELCC analysis.
44,300 GWh/year and the average annual energy is about 48,400 GWh/year in F2017, with the additions of Mica Units 5 and 6 and additional Resource Smart projects. The following list highlights some of the primary contributors to the system capability increases since 2003:

(a) Treaty and other operational changes:
   (i) Updated Non-Treaty Storage Agreement;
   (ii) Updated Canal Plant Agreement and Kootenay Entitlement; and
   (iii) Implementation of the Peace Water Use Plan and transfer of the flood control requirements from Arrow Lakes to Mica increase system average energy capability.

(b) Heritage resource additions and retirements:
   (i) Purchase of a one-third interest in the Waneta hydroelectric facility (Waneta Transaction);
   (ii) G.M. Shrum (GMS) G1-5 and G9-10 turbine upgrades;
   (iii) GMS G6-8 turbine and generator upgrades;
   (iv) Unit upgrades at Stave Falls, Seton, Bridge River, Cheakamus and Aberfeldie;
   (v) Additions of Revelstoke Unit 5 and Mica Units 5 and 6;
   (vi) Decommissioning of the Heber Diversion; and
   (vii) Removal of Burrard per the Burrard Regulation pursuant to the CEA.

(c) Inflow updates
   (i) Recent engineering study improved the quality and confidence in the Peace River stream flow data at the GMS, Peace Canyon and Site C projects.
2.3.1.3 Impacts of Planning to Average Water on BC Hydro Operations

Although BC Hydro is planning to meet load under average Heritage hydro water conditions, the amount of energy in a given year is dependent on weather conditions, including the inflows into the Heritage and non-Heritage hydroelectric system; and on the dispatch of both Heritage and dispatchable non-Heritage resources to meet load given market prices and system conditions and constraints. Figure 2-5 shows the frequency distribution of the Heritage hydro generation for the 60-year inflow record using the current resource mix. The existing Heritage hydroelectric system is capable of providing between 43,000 and 56,000 GWh/year of energy.

In addition, in any given year, there is non-firm energy from existing, committed or planned IPP resources that BC Hydro has committed to purchase. These purchases can replace market reliance in years with below average water conditions and will be
surplus in years with above-average water conditions. In F2017, BC Hydro is expected to have approximately 1,600 GWh/year of additional non-firm energy potential from IPPs.

BC Hydro and its energy trading subsidiary Powerex:

- Optimize the capability of BC Hydro’s generation system for trade, including purchasing and selling energy for trade using reservoir storage from the hydroelectric system;
- Trade power and natural gas in the region in which BC Hydro operates defined by the member utilities in the Western Electricity Coordinating Council and other select regions in North America; and
- Optimize the purchase and sale of electricity and natural gas in relation to BC Hydro’s capabilities and domestic requirements.

By having an electric system that is somewhat long on energy on average, but fairly balanced with respect to trade, BC Hydro is able to maximize the value of water stored in its Heritage hydro system, because it has the flexibility to store energy in times of surplus or low market value and sell energy at times of high demand and/or high market value. As will be further discussed in Chapter 4, markets have changed considerably over the past five years.

2.3.1.4 Columbia River Treaty

The 1964 Columbia River Treaty is an international agreement between Canada and the U.S. for the cooperative development and operation of water resources in the Columbia River basin. The Treaty has provided substantial flood control and power generation benefits to both countries.

In exchange for providing and operating the Treaty storage projects, Canada also receives an entitlement to one-half of the downstream power benefits (i.e., CE), which generates $120 million to $300 million annually (depending on power market prices) for the Province of B.C.
The Treaty can be terminated no earlier than 2024, with a minimum 10-year notice by either country. The flood control obligations change in 2024 and continue regardless if the Treaty is terminated. The Province is leading the Columbia River Treaty 2014 Review process. This review will have no impact on the CE before 2024. The post-2024 impact is under study and will not be defined within the IRP timeframe.

Since CE electricity is not generated from facilities within B.C., it has not been included in the LRBs other than as a contingency or potential short-term bridging resource, which is consistent with the CEA and the Electricity Self-Sufficiency Regulation.

2.3.1.5 Resource Smart Projects (Including Ruskin and John Hart)

Projects that have already been completed such as Revelstoke Unit 5, the turbine upgrades at Cheakamus and the Aberfeldie Redevelopment have been included in the Heritage hydro value shown in the LRB tables in Appendix 9B. Committed Resource Smart projects at GMS Units 1 to 8\(^\text{18}\) are included as incremental Resource Smart in the supply stack for the IRP.

The incremental supply from Mica Units 5 and 6 is added in F2015 and F2016, respectively. On March 30, 2012, the Ruskin Upgrade Project was granted a CPCN from the BCUC and is now a committed resource in the LRB. The energy and capacity from the John Hart Replacement Project is shown as a planned incremental supply addition, because it has not been granted a CPCN from the BCUC. Accordingly, the Heritage firm energy and ELCC values decrease as the original Ruskin and John Hart generating stations are taken out of the supply stack.

2.3.1.6 Waneta Transaction

In March 2010, the BCUC granted BC Hydro’s request to acquire a one-third interest in the Waneta hydroelectric facility, located on the Pend d’Oreille River in

\(^{18}\) Turbine upgrades on GMS Units 1-5 and capacity increases on GMS Units 6-8.
southeastern B.C., from Teck Metals Ltd. Waneta is a long-term Heritage hydroelectric resource that will supply BC Hydro with 256 MW of ELCC and 1,008 GWh/year of firm energy until the Waneta Expansion Project (WEP) comes in-service. After WEP comes in-service, the capacity and energy contributions are expected to reduce to 249 MW and 865 GWh/year respectively.\(^{(19)}\)

### 2.3.1.7 Assessment of Climate Change Impacts

Hydroelectric power generation depends on stream flow as a power source, and hence is affected by changes in the hydrological cycle, as a result of climate variation. BC Hydro has developed a climate change adaptation strategy framework to understand and address the potential impacts of climate change on BC Hydro’s operations and long-term planning. As part of the first step of BC Hydro’s climate change adaptation strategy, BC Hydro has been involved in a number of studies identifying both historical and future impacts of climate change on the water cycle and water availability in watersheds managed by BC Hydro. As indicated in BC Hydro’s letter to the BCUC (dated November 1, 2010), these studies include the information requested by the BCUC in its 2006 IEP/LTAP Decision. The results of the studies are summarized in Appendix 2C. None of the studies thus far have identified a need to change the way Heritage hydroelectric facilities are planned or relied upon. The next step in BC Hydro’s climate change adaptation strategy framework will include using operational modelling to assess how future hydrologic changes due to climate change may impact the operation of the Heritage hydroelectric system.

### 2.3.2 Heritage Thermal

BC Hydro’s Burrard plant and Prince Rupert Generating Station are the only two BC Hydro-owned thermal generating stations that serve the integrated system.

---

\(^{(19)}\) The Waneta Transaction was negotiated based on the assumption that the WEP would proceed with an in-service date of April 1, 2014. Because of the WEP’s priority rights to water flows above 25,000 cubic feet per second, the WEP would reduce the Canal Plant Agreement energy entitlement by about 143 GWh/year and 7 MW. F2014 and F2015 values reflect adjustments in the volumes during the in-service years.
2.3.2.1 Burrard Thermal

Burrard’s firm energy contribution is zero GWh/year, as a result of subsections 3(5), 6(2)(d) and 13 of the CEA, except in emergencies or by regulation: Burrard is not available for use in meeting self-sufficiency requirements, but is available for emergency conditions and potentially as a bridging resource for short-term capacity shortfalls.

Pursuant to section 2 of the Burrard Thermal Electricity Regulation, Burrard’s ELCC of 900 MW will be phased out as Mica Units 5 and 6, the Interior to Lower Mainland (ILM) Transmission Reinforcement Project (5L83) and the third transformer at the Meridian Substation are introduced into service.

2.3.2.2 Prince Rupert Generating Station

Prince Rupert’s firm energy and ELCC contributions are 180 GWh/year and 46 MW, respectively.

2.3.3 Existing, Committed and Planned IPP Supply

BC Hydro is forecast to have the rights to approximately 15,600 GWh/year and 1,400 MW of energy and ELCC in F2017 through contracts with IPPs, after taking into account attrition. Recent acquisition processes since the 2008 LTAP include the Clean Power Call, the Bioenergy Phase 1 and 2 Calls, the Integrated Power Offer, the Standing Offer Program, Waneta Expansion and other negotiated EPAs.

BC Hydro uses historical attrition experience, specific contract information and project progress to inform attrition estimates used for IPP supply. Post-attrition estimates are shown for IPP supply in the following sections and are aggregated in the LRB to inform the expected need for new resources.

BC Hydro has recently updated its assessment of firm energy contributions to the system from run-of-river facilities by aggregating the intermittent and seasonal energy from these facilities with BC Hydro’s resources (including Resource Smart additions, such as Revelstoke Unit 5 and Mica Units 5 and 6). The analysis indicates
that by aggregating these resources, BC Hydro can rely on approximately 85 per cent of the average energy from these existing and committed IPP facilities under critical water conditions, which equates to an increase of approximately 500 GWh/year. The analysis also showed that for the run-of-river IPP projects identified in the 2010 Resource Options Report (attached as Appendix 3A-1), BC Hydro estimates that it can rely on approximately 75 per cent of average energy as firm energy. More details on this assessment can be found in Appendix 3C.

2.3.3.1 Pre-Bioenergy Call Phase 1 Resources

As of January 2012, BC Hydro has 83 electricity purchase agreements (EPAs) with IPPs that were signed prior to the Bioenergy Phase 1 Call, with 14 of the associated projects not yet in commercial operation. In F2017, BC Hydro forecasts it will rely on about 10,100 GWh/year of firm energy and 1,100 MW of ELCC, post-attrition, from IPPs.

2.3.3.2 Bioenergy Call – Phases 1 and 2

Guided by the policy actions and directions contained in the 2007 B.C. Energy Plan, the 2008 B.C. Bioenergy Strategy and the CEA, BC Hydro has implemented a number of initiatives to procure bioenergy from projects that utilize wood fibre and biomass as fuel sources. BC Hydro has completed the following bioenergy initiatives:

- Bioenergy Phase 1 Call Request for Proposals – The resulting four EPAs were accepted by the BCUC under section 71 of the Utilities Commission Act (UCA) on July 31, 2009. These resources are expected to provide approximately 500 GWh/year and 60 MW by F2017, post-attrition.

- Bioenergy Phase 2 Call Request for Proposals – In August 2011, BC Hydro announced the selection of four projects for the award of EPAs. Pursuant to subsection 7(e) of the CEA, these EPAs are exempt from section 71 of the UCA. These resources are expected to provide approximately 500 GWh/year and 60 MW by F2017, post-attrition.
2.3.3.3 Clean Power Call

Upon the completion of the Clean Power Call in August 2011, BC Hydro had awarded 25 EPAs, in respect of 27 projects, with an expected volume of approximately 2,400 GWh/year of firm energy and 160 MW of ELCC by F2017, post-attrition. The Clean Power Call agreements are exempt from section 71 of the UCA pursuant to section 7(g) of the CEA.

2.3.3.4 Integrated Power Offer

Under the Integrated Power Offer, BC Hydro is targeting the acquisition of up to 1,200 GWh/year of firm energy from pulp and paper customers that qualified for federal Green Transformation Program funding. Pursuant to subsection 7(f) of the CEA, these agreements are exempt from section 71 of the UCA. To date, BC Hydro has signed five EPAs with customers that are forecast to provide approximately 900 GWh/year and 130 MW by F2017, post-attrition.

2.3.3.5 AltaGas Projects – Northwest Transmission Line

BC Hydro has signed three EPAs with AltaGas Ltd., the anchor tenant of the NTL, totalling approximately 700 GWh/year and 20 MW by F2017, post-attrition. Subsection 7(1)(a) of the CEA exempts EPAs associated with the NTL from section 71 of the UCA.

2.3.3.6 Waneta Expansion

BC Hydro signed an EPA with the Waneta Expansion Limited Partnership on October 1, 2010, which in the LRB account for approximately 195 GWh/year of firm energy and 11 MW of ELCC by F2016, post-attrition. The Waneta Expansion project is exempt from section 71 of the UCA pursuant to the “CPC/CBT Projects Exemption Continuation Regulation” issued by Ministerial Order on August 20, 2010.

---

20 The Waneta Expansion Limited Partnership is between Fortis Inc., Columbia Power Corporation and the Columbia Basin Trust.
2.3.3.7 Standing Offer Program

The Standing Offer Program (SOP) was launched in April 2008, following BCUC approval, and must be maintained by BC Hydro pursuant to section 15(2) of the CEA. The SOP was implemented to encourage the development of small and clean or renewable energy projects throughout B.C. and to streamline the process for small developers selling electricity to BC Hydro. In 2011, BC Hydro completed a two-year review of the SOP, which included recommended improvements. The SOP was subsequently revised to include changes to maximum allowable project size, eligibility of non-proven technologies and the payment price for energy.

To date, BC Hydro has signed nine SOP contracts, which are expected to provide approximately 150 GWh/year and 10 MW by F2017, post-attribution. BC Hydro is planning to contract additional electricity under the program, totalling approximately 500 GWh/year and 20 MW by F2017. Pursuant to subsection 7(h) of the CEA, these agreements are exempt from section 71 of the UCA.

2.3.3.8 Distributed Generation and Net Metering

BC Hydro continues to examine the potential for Distributed Generation across its customer base. As well, it continues to manage the Net Metering Tariff, aimed at residential and commercial customers wishing to connect a small generating unit (up to 50 kW) from a clean energy source to BC Hydro’s distribution system. Given the relatively small contributions from these two initiatives, they have not been included in the LRB.

2.3.3.9 EPA Renewal Assumptions for IPP Resources

BC Hydro assumes that, with the exception of EPAs with biomass generation facilities, all EPAs with IPPs will be renewed upon expiry and that the IPP facilities will continue to provide the same amount of electricity to BC Hydro. In BC Hydro’s view, it is not prudent to plan on the renewal of existing, committed and planned EPAs with biomass generation facilities due to fuel pricing and supply risk. In the last
10 years of the planning horizon, biomass EPAs totalling approximately 600 GWh and 60 MW of firm energy and ELCC are set to expire.

Table 2-4 demonstrates the amount of energy and capacity associated with the expiration of EPAs with IPPs over the 20-year planning horizon, not including EPAs with biomass generation facilities.

<table>
<thead>
<tr>
<th></th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
</tr>
</thead>
<tbody>
<tr>
<td>Firm Energy (GWh/year)</td>
<td>1,256</td>
<td>1,292</td>
<td>4,129</td>
<td>4,972</td>
</tr>
<tr>
<td>ELCC (MW)</td>
<td>143</td>
<td>143</td>
<td>449</td>
<td>482</td>
</tr>
</tbody>
</table>

2.3.4 ELCC from Existing, Committed and Planned Resources

A summary of the ELCC of existing, committed and planned resources is set out in Table 2-5.
## Table 2-5 ELCC in F2017

<table>
<thead>
<tr>
<th>Existing and Committed Supply</th>
<th>F2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heritage Hydroelectric</td>
<td>9,956</td>
</tr>
<tr>
<td>Heritage Thermal</td>
<td>46</td>
</tr>
<tr>
<td>Resource Smart</td>
<td>51</td>
</tr>
<tr>
<td>Existing IPP Purchase Contracts (excluding Alcan EPA)</td>
<td>716</td>
</tr>
<tr>
<td>F2006 Call</td>
<td>127</td>
</tr>
<tr>
<td>Standing Offer Program (signed EPAs)</td>
<td>10</td>
</tr>
<tr>
<td>Bioenergy Call Phase I</td>
<td>60</td>
</tr>
<tr>
<td>Waneta Transaction</td>
<td>249</td>
</tr>
<tr>
<td>Clean Power Call</td>
<td>164</td>
</tr>
<tr>
<td>AltaGas Power (NTL) (signed EPAs)</td>
<td>22</td>
</tr>
<tr>
<td>Mica Unit 5</td>
<td>465</td>
</tr>
<tr>
<td>Mica Unit 6</td>
<td>460</td>
</tr>
<tr>
<td>Waneta Expansion Project</td>
<td>11</td>
</tr>
<tr>
<td>Integrated Power Offer (signed EPAs)</td>
<td>126</td>
</tr>
<tr>
<td>Bioenergy Call Phase 2</td>
<td>60</td>
</tr>
<tr>
<td>Ruskin Upgrade Project</td>
<td>76</td>
</tr>
<tr>
<td>Conifex EPA</td>
<td>21</td>
</tr>
<tr>
<td><strong>Sub-total (a)</strong></td>
<td>12,620</td>
</tr>
</tbody>
</table>

### Planned Resources

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Standing Offer Program (future potential)</td>
<td>18</td>
</tr>
<tr>
<td>Integrated Power Offer (future potential)</td>
<td>29</td>
</tr>
<tr>
<td>John Hart Replacement Project</td>
<td>127</td>
</tr>
<tr>
<td><strong>Sub-total (b)</strong></td>
<td>174</td>
</tr>
</tbody>
</table>

**Supply Requiring Reserves**

\[ (c) = a + b \]

\[ 12,794 \]

### Reserves

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>14 per cent of Supply Requiring Reserves</td>
<td>1,795</td>
</tr>
<tr>
<td>Minus: 400 MW market reliance</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Sub-total (d)</strong></td>
<td>1,791</td>
</tr>
</tbody>
</table>

### Supply Not Requiring Reserves

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Alcan 2007 EPA</td>
<td>156</td>
</tr>
</tbody>
</table>

**Total Effective Load Carrying Capability**

\[ (f) = c - d + e \]

\[ 11,158 \]

* Numbers may not add due to rounding.
2.3.5 Energy from Existing, Committed and Planned Resources

A summary of the firm energy capability of existing resources in F2017 is shown in Table 2-6.

Table 2-6 Firm Energy Capability in F2017

<table>
<thead>
<tr>
<th>Gigawatt Hours (GWh)</th>
<th>F2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Existing and Committed Supply</strong></td>
<td></td>
</tr>
<tr>
<td>Heritage Hydroelectric</td>
<td>42,397</td>
</tr>
<tr>
<td>Heritage Thermal</td>
<td>180</td>
</tr>
<tr>
<td>Resource Smart</td>
<td>161</td>
</tr>
<tr>
<td>Existing IPP Purchase Contracts (excluding Alcan EPA)</td>
<td>6,651</td>
</tr>
<tr>
<td>Alcan 2007 EPA</td>
<td>456</td>
</tr>
<tr>
<td>F2006 Call</td>
<td>2340</td>
</tr>
<tr>
<td>Standing Offer Program (signed EPAs)</td>
<td>152</td>
</tr>
<tr>
<td>Bioenergy Call Phase I</td>
<td>537</td>
</tr>
<tr>
<td>Waneta Transaction</td>
<td>865</td>
</tr>
<tr>
<td>Clean Power Call</td>
<td>2,428</td>
</tr>
<tr>
<td>AltaGas Power (NTL) (signed EPAs)</td>
<td>688</td>
</tr>
<tr>
<td>Mica Units 5 and 6</td>
<td>201</td>
</tr>
<tr>
<td>Waneta Expansion</td>
<td>195</td>
</tr>
<tr>
<td>Integrated Power Offer (signed EPAs)</td>
<td>911</td>
</tr>
<tr>
<td>Bioenergy Call Phase 2</td>
<td>517</td>
</tr>
<tr>
<td>Ruskin Upgrade Project</td>
<td>221</td>
</tr>
<tr>
<td>Conifex EPA</td>
<td>180</td>
</tr>
<tr>
<td><strong>Sub-total</strong> (a)</td>
<td>59,079</td>
</tr>
<tr>
<td><strong>Planned Resources</strong></td>
<td></td>
</tr>
<tr>
<td>Standing Offer Program (future potential)</td>
<td>525</td>
</tr>
<tr>
<td>Integrated Power Offer (future potential)</td>
<td>193</td>
</tr>
<tr>
<td>John Hart Replacement Project&lt;sup&gt;21&lt;/sup&gt;</td>
<td>300</td>
</tr>
<tr>
<td><strong>Sub-total</strong> (b)</td>
<td>1,018</td>
</tr>
<tr>
<td><strong>Additional Non-Firm Energy Supply</strong></td>
<td></td>
</tr>
<tr>
<td>Heritage Non-Firm/Market Allowance</td>
<td>4,200</td>
</tr>
<tr>
<td><strong>Sub-total</strong> (c)</td>
<td>4,200</td>
</tr>
<tr>
<td><strong>Total Supply</strong></td>
<td></td>
</tr>
<tr>
<td>(d) = a + b + c</td>
<td>64,297</td>
</tr>
</tbody>
</table>

<sup>21</sup> John Hart is planned to provide about 835 GWh/year of average energy and 127 MW of dependable capacity post-completion in F2018; the F2017 figure reflects the reduced energy amount expected during construction.
2.4 Load/Resource Balance

The purpose of the LRB is to define the future need for resources by comparing the mid Load Forecast for the 20-year study period of the IRP with the annual capability of BC Hydro’s existing, committed and planned resources. This is done with respect to two views of the system – the energy LRB\textsuperscript{22} and the capacity LRB. As described in section 2.2, BC Hydro has prepared the LRB with and without the load from Initial LNG. Load scenarios with additional LNG, mining and oil and gas sector loads are incremental to the base LRB and are described in section 2.5.

The LRBs in this section are presented showing the current DSM Plan targets set out in the 2008 LTAP Evidentiary Update, which amount to an incremental 8,800 GWh/year and 1,500 MW of savings by F2021\textsuperscript{23}. This equates to approximately 71 per cent of BC Hydro’s forecasted load increase by F2021 without Initial LNG and 53 per cent with Initial LNG. The detailed energy and capacity LRB tables are provided in Appendix 9B. In the following sections, the discussion and presentation of the Load Forecast and surplus/deficit values will include Initial LNG load unless otherwise stated.

2.4.1 BC Hydro’s LRB

BC Hydro analyzed the load requirement with both normal load growth and incremental load from the Initial LNG facilities. The energy LRB in Figure 2-6 shows that for the 2011 Load Forecast, BC Hydro will have sufficient energy resources until F2017; without the Initial LNG load the need for new resources is deferred to F2022.

Based on the 2011 Load Forecast and existing, committed and planned resources, the energy LRB in Figure 2-6 and Table 2-7 shows resource deficits of

\textsuperscript{22} BC Hydro prepares a 20-year view of the LRB which is used to determine future long-term DSM and resource acquisition requirements given the physical capability of the system using firm energy in the planning horizon (F2015 to F2031). The operational horizon (F2012-F2014) provides the forecasted optimal reliance on existing resources in the short term given near-term market conditions, system constraints, planned outages and inflows.

\textsuperscript{23} The 2008 LTAP Evidentiary Update showed an incremental DSM target of 9,900 GWh in F2021. After reflecting achieved savings since the 2008 LTAP, which are embedded in the 2011 Load Forecast, the incremental target is reduced to approximately 8,800 GWh.
761 GWh/year in F2017; 4,935 GWh/year in F2021; and 12,478 GWh/year in F2031.

Chapter 6 contains the results of the IRP analysis to understand the trade-offs between different resource options to address these energy deficits and Chapter 9 describes BC Hydro’s plan to acquire sufficient energy resources to eliminate these energy deficits.

**Figure 2-6  Energy Load/Resource Balance**

![Energy Load/Resource Balance Chart]

**Table 2-7  Energy Surplus/Deficit (GWh)**

<table>
<thead>
<tr>
<th></th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surplus/Deficit</td>
<td>-761</td>
<td>-4,935</td>
<td>-7,367</td>
<td>-12,478</td>
</tr>
<tr>
<td>Surplus/Deficit without Initial LNG</td>
<td>3,039</td>
<td>346</td>
<td>-2,087</td>
<td>-7,197</td>
</tr>
</tbody>
</table>

The capacity LRB compares the existing, committed and planned ELCC to the 2011 Load Forecast system peak load, including reserve requirements\(^{24}\). **Figure 2-7**

---

\(^{24}\) Reserve requirements are not included in peak loads presented in section 2.2.
shows that BC Hydro has a capacity gap of about 900 MW beginning in F2017; without the Initial LNG load the capacity gap decreases to about 200 MW in F2017. The capacity LRB shown in Figure 2-7 and Table 2-8 identifies resource deficits of 936 MW in F2017; 1,167 MW in F2021; and 2,436 MW in F2031, based on the 2011 Load Forecast. Chapter 6 and Chapter 9 describe BC Hydro’s plan to acquire sufficient capacity resources to eliminate these capacity deficits.

**Figure 2-7  Capacity Load/Resource Balance**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing and Committed Resources</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td>1,200</td>
<td></td>
</tr>
<tr>
<td>Planned Resources</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011 Mid Load Forecast After DSM</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011 Mid Load Forecast After DSM with Initial LNG</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 2-8  Capacity Surplus/Deficit (MW)**

<table>
<thead>
<tr>
<th>Surplus/Deficit</th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surplus/Deficit</td>
<td>-935</td>
<td>-1,167</td>
<td>-1,697</td>
<td>-2,436</td>
</tr>
<tr>
<td>Surplus/Deficit without Initial LNG</td>
<td>-255</td>
<td>-486</td>
<td>-1,017</td>
<td>-1,756</td>
</tr>
</tbody>
</table>

The detailed information supporting Figure 2-6, Figure 2-7, Table 2-7 and Table 2-8 can be found in Appendix 9B.
2.5 Regional Load Scenarios

As described in section 2.2.2, BC Hydro has prepared a number of load forecast scenarios for IRP analysis to help to understand the impacts of meeting the large potential loads from additional LNG and mining on the North Coast and the integration of Fort Nelson load in conjunction with the electrification of the Horn River Basin in northeastern B.C.

Given the location of these loads at the end of radial transmission lines, BC Hydro is considering two alternatives for serving these requirements:

(i) System generation resources and incremental transmission, where required; or

(ii) Local generation resources.

This section describes the firm energy and ELCC requirements from a system perspective for these two regions (the North Coast and Fort Nelson/Horn River Basin) and the requirements for either more transmission capability or alternative local generation dependable capacity to meet such loads.

Transmission planning issues primarily deal with expanding BC Hydro’s transmission grid to the remote communities and reinforcing the transmission grid. BC Hydro has identified three additional regions of the province for which the transmission planning issues are potentially significant: the Coastal Region (consisting of the Lower Mainland and Vancouver Island regions), Vancouver Island itself and the South Peace.

The review and expansion of BC Hydro’s other regional transmission networks is conducted on an ongoing basis and there are a number of planning activities currently underway, including studies for North Thompson area reinforcement and

---

25 Integrating the Fort Nelson load would require a new radial transmission line in the Peace Region.
26 To meet these loads, BC Hydro also adds the estimated transmission losses to deliver the electricity to those regions.
27 BC Hydro defines the regional peak capacity resource requirements and capability in terms of dependable capacity to reflect the higher reliability requirements of transmission planning.
Iskut integration, as well as definition work for new facilities in the Long Beach and west Fraser Valley areas.

2.5.1 North Coast LNG and Mining Load Scenarios

The system energy and capacity LRBs with the LNG3 load and the incremental high mining load scenarios are shown in Figure 2-8 and Figure 2-9. The resulting surplus/deficit amounts are shown in Table 2-9 and Table 2-10. These show that LNG3 would increase the need for new supply by 6,400 GWh/year and 800 MW in F2020, growing to 12,800 GWh/year and 1,700 MW in F2026. The high mining load is forecasted to require an additional 70 GWh/year and 20 MW of additional supply in F2014, growing to approximately 2,000 GWh/year and 270 MW by F2018.
Table 2-9  
<table>
<thead>
<tr>
<th>Energy Surplus/Deficit with LNG3 and High Mining Load Scenarios (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2017</td>
</tr>
<tr>
<td>---------------------------------</td>
</tr>
<tr>
<td>Surplus/Deficit with LNG3</td>
</tr>
<tr>
<td>Surplus/Deficit with LNG3 and High Mining</td>
</tr>
</tbody>
</table>

Figure 2-9  
Capacity Load/Resource Balance with LNG3 and High Mining

The electricity supply to the North Coast region, shown in Figure 2-10, is supplied by a radial transmission line from Prince George to Terrace that consists of the following three 500 kV circuits: 5L61 from Williston (WSN) to Glenannan (GLN),
5L62 from GLN to Telkwa (TKW), and 5L63 from TKW to Skeena (SKA). The key regions of increased interest in LNG and mining activities are in the Bob Quinn, Prince Rupert and Kitimat regions.

Figure 2-10  North Coast Transmission System

The regional load/resource balance in Figure 2-11 shows that approximately 500 MW of new transmission transfer capability or local generation is required in F2016, and an incremental 700 MW is required in F2020, growing to approximately
1,500 MW in F2026 with LNG3. A high mining scenario would increase the requirements by about 270 MW by F2017.

**Figure 2-11** North Coast Load/Resource Balance

![Graph showing load and resource balance for North Coast](image)

**Northwest Transmission Line**

The NTL project is shown in Figure 2-12. It includes the construction of a new 287 kV/335 km circuit extending from the Skeena substation near Terrace to Meziadin Junction, and north to a new substation to be located near Bob Quinn Lake. The conductors of this new line will be rated for up to 465 MW of power flow.

The new NTL line will provide an interconnection point for clean generation projects (including the AltaGas projects referenced in section 2.3.3.5) and a reliable supply of clean power for potential industrial developments in the area. It will also provide
some northwestern communities with the opportunity to interconnect to the grid and eliminate their reliance on diesel generation.

On February 23, 2011, the B.C. Environmental Assessment Office announced that the NTL had been granted an Environmental Assessment Certificate. The expected in-service date of the NTL project is May 2014.

**Figure 2-12  Northwest Transmission Line**

2.5.2  Fort Nelson Integration and Horn River Basin Electrification

The system energy and capacity LRBs for a load forecast scenario that assumes an integrated Fort Nelson load and the electrification of the Horn River Basin are shown in **Figure 2-13** and **Figure 2-14**. The resulting surplus/deficit amounts are shown in
Table 2-11 and Table 2-12. The loads\(^{28}\) in this scenario are 1,800 GWh/year and 260 MW in F2021, growing to 4,200 GWh/year and 660 MW in F2031.

Figure 2-13  Energy Load/Resource Balance with Fort Nelson and Horn River Basin

<table>
<thead>
<tr>
<th>Fiscal Year (year ending March 31)</th>
<th>2011 Mid Load Forecast After DSM</th>
<th>2011 Mid Load Forecast After DSM with Mid FN/HRB</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2014</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2015</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2016</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2017</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2018</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2019</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2020</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2021</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2026</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2027</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2028</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2029</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2030</td>
<td></td>
<td></td>
</tr>
<tr>
<td>F2031</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 2-11  Energy Surplus/Deficit with Fort Nelson and Horn River Basin Load Scenario (GWh)

<table>
<thead>
<tr>
<th></th>
<th>F2017</th>
<th>F2021</th>
<th>F2026</th>
<th>F2031</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surplus/Deficit with Fort Nelson and Horn River Basin</td>
<td>-659</td>
<td>-6,303</td>
<td>-10,706</td>
<td>-16,688</td>
</tr>
</tbody>
</table>

\(^{28}\) The net requirements do not increase by this amount because Fort Nelson Generating Station would provide approximately 430 GWh/year of energy and 72 MW of dependable capacity.
2.5.2.1 Fort Nelson

The Fort Nelson region is located within BC Hydro’s service area in the northeast of B.C. The region is not connected to BC Hydro’s integrated grid, but is integrated with Alberta’s electricity system via a single 144 kV transmission line. The region includes electrified communities located within the Northern Rockies Regional Municipality, as well as industrial customers located along the 144 kV transmission corridor linking Fort Nelson to the Alberta system. It does not include the HRB, which is described in the next section.
BC Hydro serves customers in the Fort Nelson region with electricity generated at its recently upgraded (47 MW to 73 MW) Fort Nelson Generating Station (FNG) and transmission service (38.5 MW) from Alberta. With these two resources, BC Hydro can currently meet its single contingency (N-1\textsuperscript{29}) reliability criterion, such that when one of element is out of service, the entire Fort Nelson region load can still be served.

**Figure 2-15** shows the load in the Fort Nelson region alone (i.e., not including the potential Horn River Basin shale gas-related load) is expected to grow from its current level of about 30 MW to between 50 MW (mid forecast) and 90 MW (high scenario) by about F2020. Both of these load scenarios would exceed the 38.5 MW firm (N-1) capability of the existing resources, since the transmission service from the Alberta Electric System Operator (AESO) is limited to 38.5 MW and the loss of the 47 MW FNG gas turbine generator results in the loss of the heat source to the 26 MW FNG steam turbine generator, resulting in a 73 MW single-contingency. Fort Nelson load is expected to remain flat under the low load scenario.

\textsuperscript{29} The primary reliability criterion is based on the largest single contingency (or N-1) standard, i.e., sufficient resources are available to meet the area load with the single largest element (the transmission line to the area or local generation) out of service.
2.5.2.2 Horn River Basin

The HRB region encompasses a large geographic area generally extending north and east of Fort Nelson. It is a region with significant “unconventional” natural gas reserves, which are contained in shale formations and require new, more aggressive techniques (e.g., hydraulic fracturing) to extract the gas.

BC Hydro currently serves the Fort Nelson region, but not the HRB. To date, the natural gas development activity in recent years has not translated into applications for electricity service. However, issues such as climate change and GHG legislation have created opportunities to use electricity as a means of reducing the GHGs that result from the HRB shale gas production, processing and transportation.

Figure 2-16 shows the three HRB electric load scenarios (peak demand), along with the Fort Nelson mid peak demand (assuming the HRB is not electrified) and supply capability, that were developed for the IRP. In each case, it is assumed that...
BC Hydro continues to serve the existing and new Fort Nelson load. A 47-year outlook is provided, as BC Hydro considered the implications of changing load requirements associated with changing gas production volumes over a long time period in its analysis of alternatives in Chapter 6. For the mid Fort Nelson/HRB scenario, an incremental 300 MW of firm load-serving capability could be required by F2021, growing to approximately 600 MW by F2031.

For additional information on the Fort Nelson/HRB scenarios and analysis please refer to Chapter 6 and Appendix 2E.
2.5.3 Coastal Region (Lower Mainland/Vancouver Island)

The Coastal region is made up of the Lower Mainland and Vancouver Island regions and is grouped together for the purpose of identifying transmission upgrades from the Interior to Lower Mainland regions or requirements for alternative local dependable capacity generation. Although transmission upgrades are only considered between the Interior and Lower Mainland regions, the transmission capability from the Interior must be able to serve both the Lower Mainland and Vancouver Island loads on the other side of the ILM cut-plane.

The existing ILM portion of the bulk transmission system will be reinforced by the construction of circuit 5L83, a second 500 kV single-circuit, 50 per cent series-compensated transmission line between the Nicola and Meridian substations. The addition of this line, expected to enter service in January 2015, will increase the firm (N-1) ILM transfer capability to 6,550 MW.

The LRB for this region is shown in Figure 2-17 and demonstrates that in the absence of new dependable capacity supply in the Coastal region, new transmission transfer capability will be required in F2025.
2.5.4 Vancouver Island

The load growth on Vancouver Island is expected to be modest over the 20-year planning horizon. The load on Vancouver Island is supplied by the Lower Mainland – Vancouver Island (LM-VI) transmission connections and the dependable capacity of the generating plants on the island. The two major 500 kV submarine cables to Vancouver Island continue to be rated as being in good shape, placing any replacement considerations outside of the IRP planning horizon.

The 230 kV AC Arnott-to-Vancouver Island Terminal cable circuit, which entered service in January 2009, increased the firm LM-VI transfer capability to 2,000 MW (1,900 MW in summer). Figure 2-17 shows that no further transmission upgrades between the Lower Mainland and Vancouver Island or on-island dependable capacity generation are required in the 20-year planning horizon.
2.5.5 South Peace Region

The main focus of the transmission assessment in this IRP is to identify the requirements for the bulk transfer of power to the regional transmission network. Expansion of BC Hydro’s regional transmission network in the South Peace region is addressed in this context. The Dawson Creek/Chetwynd Area Transmission (DCAT) project is a key regional transmission project in the South Peace region.
The DCAT project is designed to address the electricity supply constraints in the Dawson Creek and Groundbirch areas. The existing transmission infrastructure serving the areas consist of a 138 kV transmission line (1L358) from Chetwynd Substation to Bear Mountain Terminal, a 138 kV transmission line (1L362) from BMT to the Dawson Creek Substation (DAW), and a 138 kV transmission line (1L377) from Taylor Substation to DAW. It has a transfer capacity of 150 MW under system.
normal conditions (N-0 criterion) and 70 MW on a single-contingency outage condition (N-1 criterion). As shown in Figure 2-20, an upgrade of the Dawson Creek transmission system is required to meet existing and future load growth in the Dawson Creek and Groundbirch areas, which is expected to be the most significant load growth the BC Hydro system has experienced in recent history.

Figure 2-20 Dawson Creek Load/Resource Balance

The extraordinary load growth is largely attributable to the development of the Montney natural gas play. Natural gas producers have expressed a strong interest in connecting to the BC Hydro electric system to meet their power needs.

Further details on the need for new transmission supply in the Dawson Creek/Chetwynd region can be found in BC Hydro’s application for a CPCN for the DCAT project.