BC hydro

Integrated Resource Plan

Chapter 2

Load-Resource Balance

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2.1 Introduction

As set out in Chapter 1, the second step in the Integrated Resource Plan (**IRP**) analytical framework is to forecast BC Hydro's future electricity demand requirements. Energy and capacity Load-Resource Balances (**LRBs**) establish the need for incremental Demand-Side Management (**DSM**) and supply-side and bulk transmission resources by comparing the December 2012 Load Forecast (referred to as the **2012 Load Forecast**) to existing and committed resources. A gap exists if forecasted customer load exceeds the supply available to serve that load.

As required by BC's Electricity Self-Sufficiency Regulation, and consistent with other utilities, BC Hydro bases the need for new resources on its mid load forecast; this methodology has been endorsed by the British Columbia Utilities Commission (**BCUC**) in proceedings including the 2008 Long Term Acquisition Plan (**LTAP**).

This chapter reviews the 2012 Load Forecast and summarizes how Liquefied Natural Gas (**LNG**) load is addressed (section 2.2); examines the existing and committed resources in the context of BC Hydro's planning criteria, the B.C. *Clean Energy Act (**CEA**)* and the 2007 BC Energy Plan (section 2.3); presents the integrated system energy and capacity LRBs with and without Expected LNG load (section 2.4); and reviews regional planning issues and constraints in five regions: the North Coast; Fort Nelson/Horn River Basin (**HRB**); Coastal (Lower Mainland/Vancouver Island together as a region); Vancouver Island on its own; and South Peace (section 2.5). The 2012 Load Forecast document is contained in Appendix 2A of this IRP.

The load forecast and LRBs are summarized in this chapter with a focus on milestone years in five-year increments: F2017 (self-sufficiency target year and start of the planning horizon); F2023; F2028; and F2033 (final year of the planning horizon). All values shown include transmission and distribution line losses unless otherwise stated.

2.2 BC Hydro's 2012 Load Forecast

BC Hydro's load forecast is produced annually and is a key input in determining the LRB. BC Hydro's load forecasting methodology has been the subject of review in a number of BCUC regulatory proceedings, including the 2008 LTAP, the 2011 Ruskin Dam and Powerhouse Upgrade Project Certificate of Public Convenience and Necessity (**CPCN**), and the 2011 Dawson Creek/Chetwynd Area Transmission Project (**DCAT**) CPCN. In its 2008 LTAP Decision, the BCUC accepted BC Hydro's load forecast methodology and a similar methodology has been adopted in this IRP.

BC Hydro includes verifiable information in its mid load forecast to reflect possible load increases or reductions for current customers. In addition, the future demands of new mining and oil and gas customers are generated with reference to, among other things, sources such as expert third party consultants, reports from government agencies such as the B.C. Oil and Gas Commission, and various other company-specific reports.

Regarding future demand from the LNG industry, BC Hydro considered a range of potential LNG loads as scenarios in the 2012 Load Forecast. Future demand from the LNG industry warrants specific analysis given the scope of its potential impact on resource plans. As discussed in section 1.1.2, BC Hydro and the B.C. Government have been working with LNG proponents on options for meeting all or some of the energy needs of proposed LNG plants with power from the BC Hydro system. BC Hydro's current estimate suggests the LNG industry could need in the range of 800 to 6,600 GWh/year (100 to 800 MW), with an Expected LNG load of approximately 3,000 GWh/year and 360 MW by F2022. This load is referred to as 'Expected LNG'. BC Hydro is monitoring 12 publicly-announced LNG projects proposed for Kitimat, Prince Rupert and other areas of the B.C. North Coast, Howe Sound in the Lower Mainland and Campbell River on Vancouver Island. Information regarding these proposed facilities is found in section 2.2.2.

The 2012 Load Forecast presented in this section is shown before future incremental DSM savings in F2013 and beyond. DSM is treated like other potential resources that can fill the LRB energy and capacity gaps going forward. This treatment is consistent with the BCUC's Resource Planning Guidelines which states that DSM "should not be reflected in the utility's gross demand forecasts".

BC Hydro performs an uncertainty assessment on its mid load forecast to identify a high load and low load forecast using a Monte Carlo model. This section also details BC Hydro's high and low load forecasts (section 2.2.4).

From a comparative perspective, the 2012 Load Forecast methodology is similar to that used for the 2008 Load Forecast, reviewed in the 2008 LTAP regulatory proceeding, 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 2012 Load Forecast. EV load impacts are forecast to be minimal in the first 10 years, resulting in an increase of 14 GWh/year in F2017 before losses, rising to 1,396 GWh/year by F2033.
- 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. 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 certain codes and standards resulted in a degree

of double counting. This modification to the 2012 Load Forecast is further detailed in section 2.2.5.

- Modifications that have been made to the development of the uncertainty forecast bands using the Monte Carlo model are described in section 2.2.5.

2.2.1 2012 Load Forecast Overview

The 2012 mid Load Forecast for the energy and peak demand requirements of BC Hydro's integrated system, before DSM and including projected rate impacts[1] and including Expected LNG, are presented in Table 2-1 and Table 2-2.

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

(GWh)	F2017	F2023	F2028	F2033	Compound Growth Rate	
					F2014-F2023 (%)	F2014-F2033 (%)
Mid Load Forecast	63,238	71,721	75,475	80,316	2.2	1.7
Expected LNG		3,000	3,000	3,000		
Mid Load Forecast + Expected LNG	63,238	74,721	78,475	83,316	2.7	1.9

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

(MW)	F2017	F2023	F2028	F2033	Compound Growth Rate	
					F2014-F2023 (%)	F2014-F2033 (%)
Mid Load Forecast	11,681	12,950	13,817	14,915	1.8	1.6
Expected LNG	0	360	360	360		
Mid Load Forecast + Expected LNG	11,681	13,310	14,177	15,275	2.1	1.7

[1] The BCUC in its 2006 IEP Decision, page 154, ordered that BC Hydro include a forecast of BC Hydro's rates in its load forecasts. BC Hydro has included rate forecasts in its load forecasts since 2008. Note that actual rate increases are determined through BC Hydro's Revenue Requirements Application, and may differ from forecast assumptions.

Figure 2-1 shows BC Hydro's forecast energy demand for the integrated system before DSM, including projected rate impacts and including Expected LNG and the associated range of LNG demand. Figure 2-2 does the same for peak demand.

Figure 2-1 2012 Energy Mid Load Forecast (before DSM)

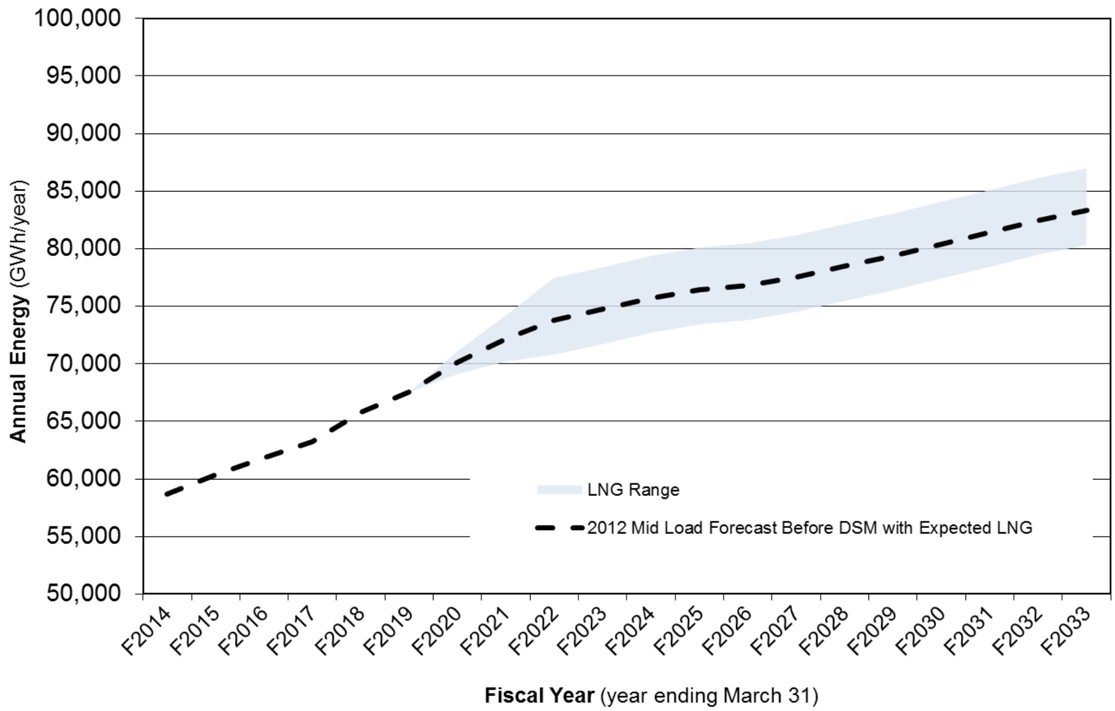
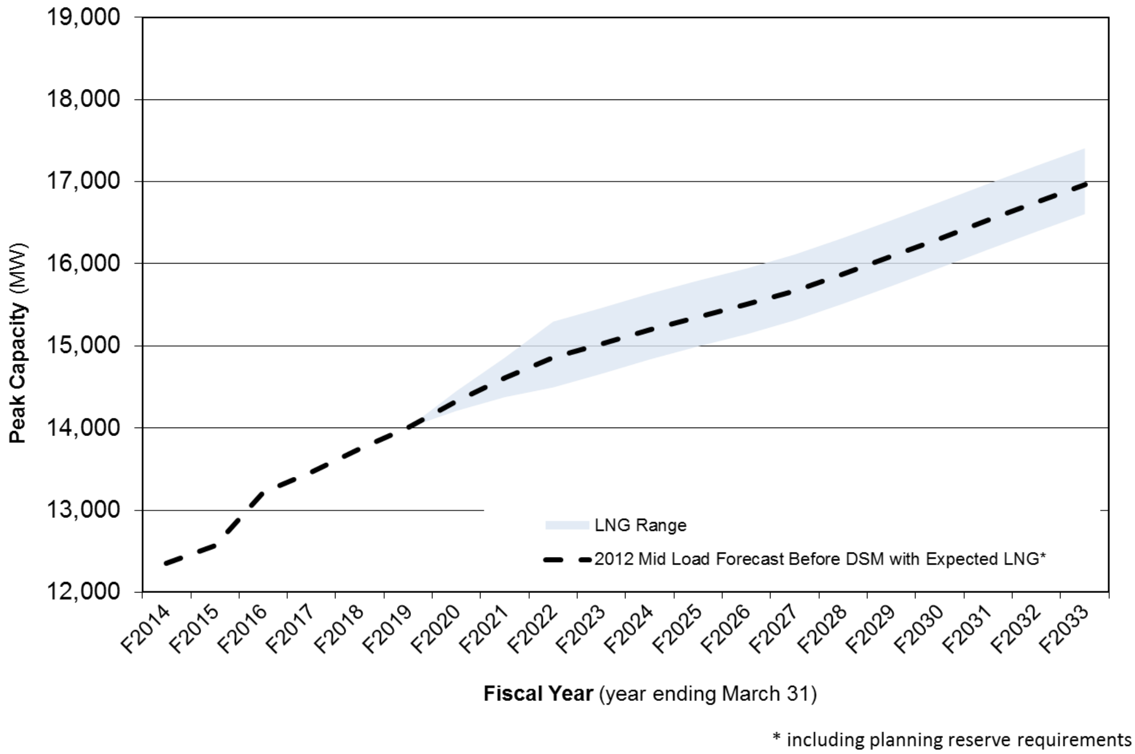


Figure 2-2 2012 Peak Demand Mid Load Forecast (before DSM)



2.2.2 Energy Load Forecast – Key Trends

BC Hydro's 2012 mid Load Forecast by sector, including projected rate impacts, is shown in Table 2-3. The industrial sector represents the largest potential for early new load growth, particularly in LNG, oil and gas, and mining.

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

Energy Load (GWh/year)	F2017	F2023	F2028	F2033	Compound Growth Rate F2014-F2023 (%)	Compound Growth Rate F2014-F2033 (%)
Residential	19,761	22,291	24,409	26,471	2.0	1.9
Commercial	17,815	20,323	21,865	23,700	2.2	1.8
Industrial (without LNG)	19,016	21,207	20,836	21,273	2.5	1.2
New Westminster/FortisBC Contractual Sales	995	1,535	1,614	1,654	5.0	2.7
Domestic Sales (without LNG)	57,587	65,356	68,725	73,097	2.3	1.7
Expected LNG	0	3,000	3,000	3,000		
Domestic Sales (with Expected LNG)	57,587	68,356	71,725	76,097	2.8	1.9

2.2.2.1 Residential Sector

BC Hydro’s residential sector currently represents about 35 per cent of BC Hydro’s total sales. Sales to the residential sector are weather sensitive, primarily due to winter space heating demand. Residential sales are expected to grow by 1.9 per cent per year to F2033 before DSM. The average use per residential account is expected to grow slowly, at somewhat less than 1 per cent per year.

BC Hydro’s residential sector historically has been the most stable in terms of consistent growth trends and relative insulation from economic cycles. The drivers of the residential forecast are the use-per-account times the number of accounts. The ‘use-per-account forecast’ is determined by using BC Hydro’s industry-standard Statistically Adjusted End Use Model. The model uses economic drivers of the load such as population growth, personal income and appliance stock efficiency. Potential EV load has been included in the 2012 mid Load Forecast. Although modest initially, EV demand could become significant in the long term. Modeled EV demand is sensitive to factors such as the relative price of electricity versus gasoline, and the relative costs of EVs versus conventional vehicles. Refer to

Appendix 4 of the 2012 Load Forecast document, which is Appendix 2A to this IRP, for a discussion of EVs.

Key trends in the residential sector include improving efficiencies in lighting and appliances and the counter-trend of growth in new electricity uses, such as PVRs/set top boxes. Trends in housing stock are also important, with an increasing shift to multi-family housing which has a lower use per account, but with an offsetting trend towards larger units in the respective housing types.

2.2.2.2 Commercial Sector

BC Hydro's commercial sector currently represents about 31 per cent of BC Hydro's total sales. Most of the commercial sector load is made up of distribution load such as large and small offices, health service facilities and warehouses. Commercial sales also include larger customers such as ports, universities, airports and pipelines.

Commercial sales are expected to grow by 1.8 per cent per year to F2033 before DSM. The commercial sector's electricity consumption can vary considerably from year to year, reflecting the level of activity in B.C.'s service sector. The forecast drivers for this sector include the efficiency of end-use equipment, retail sales projections, employment, and commercial GDP output. The commercial distribution forecast uses BC Hydro's industry-standard Statistically Adjusted End Use Model. Growth in this sector is expected to follow general provincial economic trends.

2.2.2.3 Industrial Sector

BC Hydro's industrial sector currently represents about 32 per cent of BC Hydro's total sales. Without LNG, industrial sales are expected to grow by 1.2 per cent per year to F2033 before DSM. The industrial sector is expected to see the most aggressive growth of the key sectors in the next 10 years (2.5 per cent per year compounded demand growth without LNG), due to rapid growth in mining and oil and gas activity.

BC Hydro prepares its industrial load forecast on a customer-by-customer basis, considering the sector-specific issues that each customer faces. The customer forecast is informed by production forecasts and industry outlooks from third party experts, industry publications and forecasts, and information from BC Hydro's own key account representatives, who are in regular contact with these customers.

Demand from this sector is challenging to forecast due to its volatility and sensitivity to factors such as unpredictable commodity prices, 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. Key trends in the industrial sector include the following:

- Mining – growth in the B.C.'s mining sector will depend on global commodity prices, which in turn is driven by economic activity both domestically and in the export markets. Other key factors affecting growth include the availability of financing, regulatory and environmental approvals, and First Nations issues.
- Forestry – pulp and paper sales are dependent on commodity prices and the competitiveness of B.C.-based mills. Fibre supply is an issue due to the pine beetle infestation. Forest product sales depend on the speed of the U.S. housing recovery and the availability of wood.
- Smaller industrial – is primarily made up of forestry, coal mining, and oil and gas served at distribution voltages. Sales to other industrial distribution sectors beyond these ones are assumed to follow general economic trends.
- Oil and Gas – Shale gas has transformed the industry and brought significant quantities of new, low-cost natural gas to the market. BC Hydro expects that electricity service to gas producers will be one of the largest growth areas, and that this will largely occur in the northeast quadrant of the province. Sales to gas producers will hinge on gas market prices, which have been recently suppressed due to the amount of new gas brought to the continental market.

LNG could provide a significant uplift to gas producers in terms of providing a premium sales market.

2.2.2.4 Liquefied Natural Gas

With respect to the LNG industry, BC Hydro is monitoring 12 publicly-announced LNG facilities in B.C. Information regarding the status of these proposed facilities is contained in Table 2-4. The potential electricity demands are drawn from LNG proponents that have submitted Project Descriptions to the B.C. Environmental Assessment Office (**EAO**) and/or the Canadian Environmental Assessment Agency (**Agency**) unless otherwise noted.

Table 2-4 LNG Summary

Project Name	Proponent	Location	NEB Export Permit	Environmental Assessment Approval	Export Potential (mtpa)[2]	Capacity Load (MW)[3]
Kitimat LNG	Apache, Chevron	Kitimat	Yes	Yes, EAO	10	Not publicly available
LNG Canada	Shell Canada, PetroChina, Korea Gas, and Mitsubishi	Kitimat	Yes	In progress: EAO, Agency	24	90 - 150
Douglas Channel Energy Project	BC LNG Export Cooperative LLC: LNG Partners (Texas) and Haisla Nation	Kitimat	Yes	N/A – not triggered	1.8	0[4]

[2] Export potential is a maximum limit as provided in project submissions for National Energy Board export permits which can be found at http://www.neb-one.gc.ca/clf-nsi/index.html unless otherwise noted. Expressed in million tonnes per annum (mtpa).

[3] Information on potential electrical capacity requirements may be found at http://www.eao.gov.bc.ca/ unless otherwise noted.

[4] There is currently no expected electric service requirement for Douglas Channel Energy Project.

Project Name	Proponent	Location	NEB Export Permit	Environmental Assessment Approval	Export Potential (mtpa)[2]	Capacity Load (MW)[3]
Pacific Northwest LNG	PETRONAS, JAPEX	Prince Rupert	In Progress	In progress: EAO, Agency	19.7	No publicly available information provided on load which could be served by BC Hydro[5]
Prince Rupert LNG	BG Group	Prince Rupert	In Progress	In progress: EAO, Agency	21.6	140 - 200
WCC LNG	Imperial Oil and Exxon Mobil Canada	Prince Rupert	In Progress	Not Available	30	Not available
Woodfibre LNG	Pacific Oil and Gas Group	Squamish	In Progress	Not Available	2.1	Not available
TBD	CNOOC, Nexen, Inpex, and JGC	Prince Rupert	Not Available	Not Available	Not Available	Not available
TBD	SK E&S	Prince Rupert	Not Available	Not Available	Not Available	Not available
TBD	Woodside	Prince Rupert	Not Available	Not Available	Not Available	Not available
TBD	Alta Gas, Indemitsu	TBD	Not Available	Not Available	2[6]	Not available
Discovery LNG	Quicksilver	Campbell River	Not Available	Not Available	Not Available	Not available

2.2.3 Peak Demand Load Forecast – Key Trends

BC Hydro creates a 20-year peak load forecast at the same time as the energy forecast. BC Hydro's peak demand typically occurs on a cold winter day, driven by space heating requirements. Among distribution voltage customers, the peak is most dependent on the ambient temperature. Trends in peak demand growth depend on

[5] The Project Description states (pages 10-11) that the total estimated power required is about 700 MW, with the main options being mechanical drive and Combined Cycle Gas Turbine-powered electric drive on site. The Project Description notes that "additional power supply options … are under consideration. For example, Pacific Northwest LNG will consider designing the facility … to allow for connection to sources of renewable energy to power ancillary infrastructure, if these sources were to become available as a stable and reliable source of electrical energy supply".

[6] Source: http://www.albertaoilmagazine.com/2013/01/altagas-to-pursue-lng-export-facility-with-japanese-partner/.

projected accounts growth and the same economic factors that drive the energy forecast. The peak load forecast is built up on an account-by-account basis at the same time that the industrial transmission customer energy forecast is created, as described in section 2.2.2. Additional considerations in generating the peak forecast include planned facility expansions, industry trends and growth in demand for B.C. exports of commodities. The peak demand forecast generally follows the trends in the energy load forecast.

2.2.4 Load Forecast Uncertainty

BC Hydro uses a Monte Carlo model to calculate the uncertainty band around its mid load forecast (for the integrated system not including large LNG loads).[7] Details on the Monte Carlo model and how the underlying uncertainties are estimated are included in the 2012 Load Forecast document (Appendix 2A). This model produces an 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 represented by GDP growth, weather, electricity rates and elasticities. Probability distributions were assigned to each input variable and a model was specified to define a mathematical relationship between the input variable and electricity demand for the residential, commercial and industrial sectors.

In the past, in the case of the industrial sector, a direct elasticity relationship between economic growth as measured by GDP and industrial sector demand was assumed and applied in the Monte Carlo model. In the 2012 Load Forecast this methodology was modified (as described in more detail in the following section) to add distributions for each of the large mining, oil and gas, forestry and remaining sectors. All of the distributions are perturbed (i.e., moved up and down) in the Monte Carlo model simultaneously, with the intention of creating:

- A high band, which represents the expected outcome if the load exceeds the 80^{th} percentile in each year

[7] Large single loads are not included as they do not lend themselves to a probabilistic assessment.

- A low band, which represents the expected outcome if the load is less than the 20th percentile in each year

The resulting high and low bands result in approximately 8 per cent and 92 per cent exceedance probabilities, respectively. As discussed in section 2.1, for planning purposes BC Hydro applies its mid load forecast. The high and low forecast bands indicate the magnitude of load uncertainty in a given year and are used for Contingency Resource Plans (**CRP**s). (BC Hydro's CRPs are addressed in section 8.4). Planning to the low load forecast would almost certainly result in BC Hydro not being able to meet its service obligation, whereas planning to the high load forecast would likely result in oversupply and adverse rate impacts.

Figure 2-3 and Figure 2-4 show the 2012 mid energy and peak Load Forecasts including the high and low uncertainty band forecasts before DSM and including projected rate impacts, excluding LNG. A high case for LNG and other large industrial sectors is examined in section 2.2.4.1.

Figure 2-3 2012 Energy Mid Load Forecast and Uncertainty Band (excluding LNG)

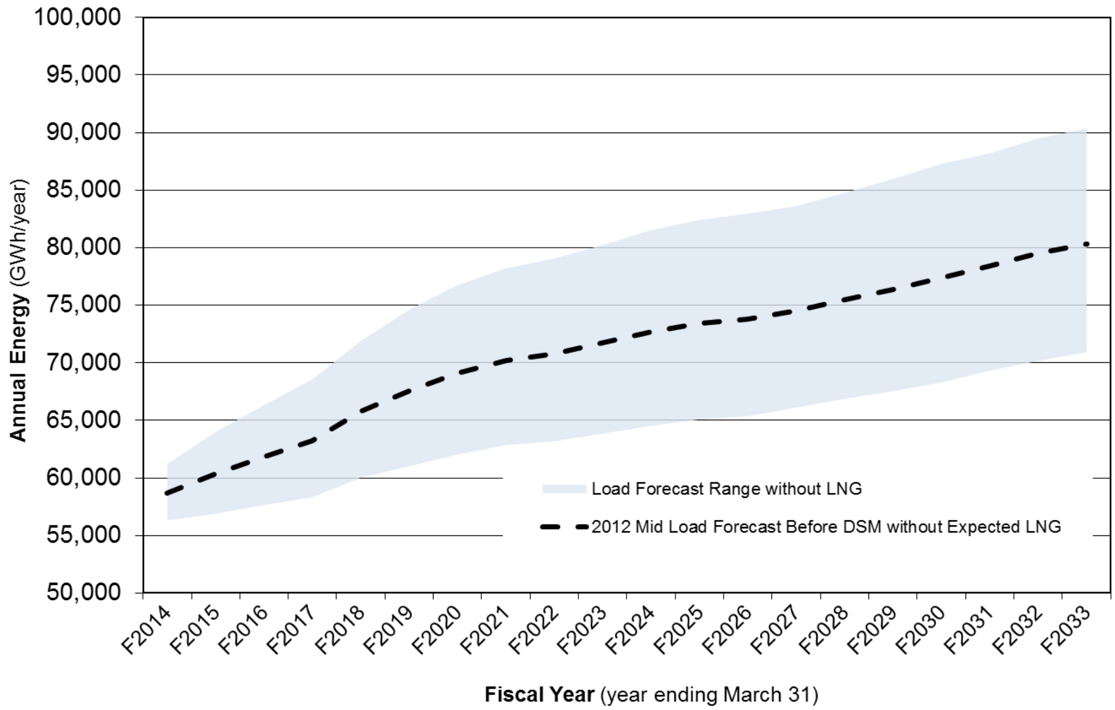
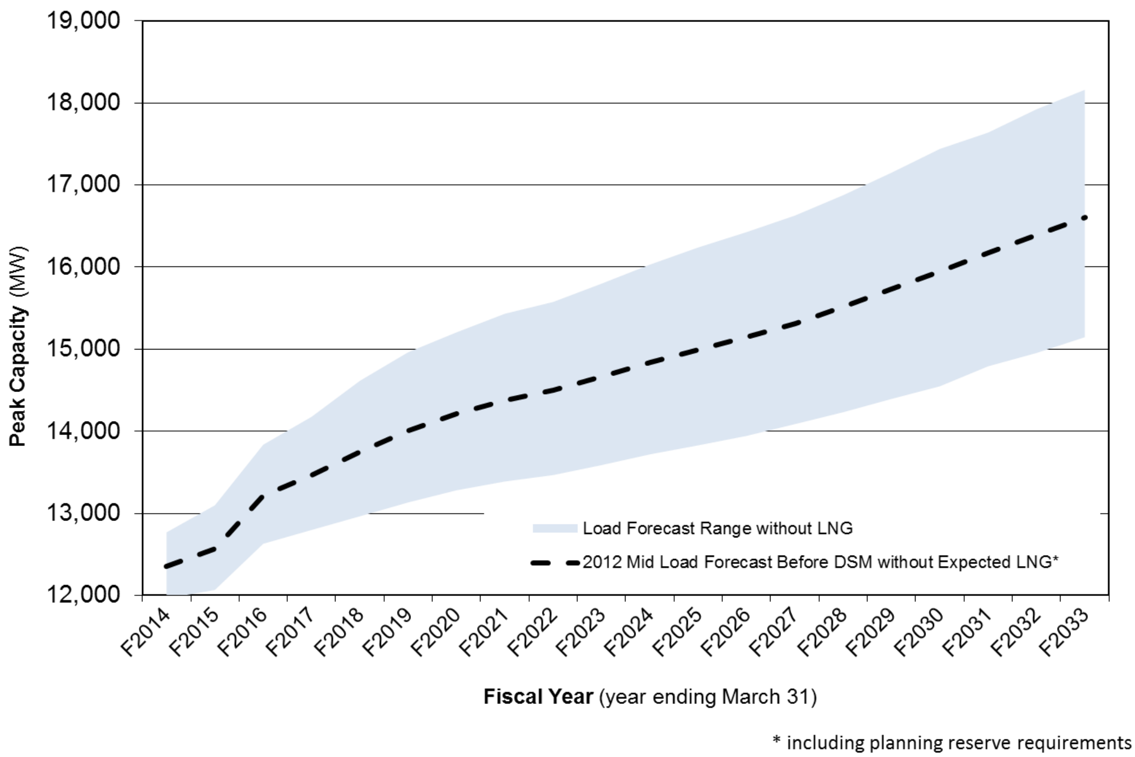


Figure 2-4 2012 Peak Mid Demand Load Forecast and Uncertainty Bands (excluding LNG)



2.2.4.1 The High Load Regional Perspective

BC Hydro performed scenario analysis to examine potentially large new loads that could emerge due to LNG, mining in the North Coast, and oil and gas in northeastern B.C. BC Hydro's probabilistic load forecasting approach is not suitable for this analysis given the size of potential demand and impact these requirements would have on future resource plans. The scenario analysis is further described in Chapter 6.

The range of loads identified by sector are as follows:

- LNG sector – BC Hydro's current estimate suggests the LNG industry could need in the range of 800 to 6,600 GWh/year (100 to 800 MW), with an Expected LNG load of approximately 3,000 GWh/year and 360 MW by F2022.

- Mining sector – BC Hydro constructed a scenario that examines higher mining load in the North Coast region, in addition to what is in the 2012 mid Load Forecast. The 2012 mid Load Forecast includes approximately 130 MW of load in the Northwest Transmission Line (**NTL**) region, which is the probability weighted sum of the forecasted mining loads in this region. The higher mining scenario that BC Hydro considered is 380 MW and 2,600 GWh/year by F2019.
- Oil and gas sector – BC Hydro constructed three scenarios to examine the HRB shale gas industry, a potentially large load north of Fort Nelson that could require electricity service from BC Hydro for gas extraction and transport. Transformative technologies have made shale gas plays in northeastern B.C. economically viable. The HRB is an immense gas resource whose viability will be improved if its production is used to supply LNG exports in markets commanding a higher commodity price. These scenarios explore the electrification of a significant share of the work energy required to bring this gas to market.

The incremental energy and peak loads are shown in section 2.5.

2.2.4.2 Transmission Uncertainty Methodology and High and Low Load Forecast

Given the large size of the transmission customer loads and the binary nature of these loads, the transmission sector load has a greater potential volatility relative to residential and commercial sector loads. To better reflect the process of developing the uncertainty bands, the 2012 Load Forecast was modified for the large transmission sector to include a more detailed and sector-specific analysis of the range of potential loads.

BC Hydro developed discrete long-term high and low scenarios for forestry, oil and gas (including commercial pipelines), mining and the remaining portion of the transmission sector. This was based on a qualitative appraisal of demand factors and risks specific to each of these sectors. These high and low scenarios were then translated into a probability distribution for each sector. A correlation matrix between sectors was then developed as an input into the Monte Carlo model that was used for the creation of the overall uncertainty bands. This addition produced an approximately 50 per cent wider uncertainty distribution than was generated in the 2011 Load Forecast. More details on BC Hydro's load forecast methodology can be found in Appendix 2 of the 2012 Load Forecast document (Appendix 2A) attached to this IRP.

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 Decision 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 DSM codes and standards savings against the EIA documentation, and identified which individual codes and standards result in potential double counting. Based on this analysis, the upwards load adjustments as a result of DSM double counting in the 2012 Load Forecast are approximately 270 GWh before losses 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 the IRP.

2.3 Existing and Committed Supply-Side Resources

The other major input to the LRB for the IRP analysis is the capability of the existing and committed supply-side resources that serve the integrated system. Definitions of these two categories of supply-side resources follow:

- "Existing resources" include BC Hydro's Heritage hydroelectric and thermal (natural gas-fired) resources, as well as Independent Power Producer (**IPP**) facilities delivering electricity to BC Hydro
- "Committed resources" are resources for which material regulatory approvals have been secured (BCUC approval, either secured or through exemption; and environmental assessment related), if required, and for which the BC Hydro Board of Directors has authorized implementation. Examples are Mica Units 5 and 6. Recent committed resources include the contributions from the Ruskin Upgrade Project; three Electricity Purchase Agreements (**EPAs**) related to the Conifex power project and the Integrated Power Offer (**IPO**); and the John Hart Generating Station Replacement Project (**John Hart Replacement Project**).

As described in sections 1.2.2.1 and 1.2.2.2, BC Hydro defines the firm energy load carrying capability (**FELCC**) and effective load carrying capability (**ELCC**)[8] in the LRBs using the generation energy planning criterion and the generation capacity planning criterion. 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 LRBs.

2.3.1 Heritage Hydro

BC Hydro has 30 existing hydroelectric facilities on the integrated system[9] with an average energy capability of approximately 48,200 GWh/year in F2017, including

[8] 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.

[9] Clayton Falls Hydroelectric Generating Station is a non-integrated Heritage hydroelectric facility located about 5 km west of Bella Coola.

contributions from BC Hydro's existing Heritage hydro assets, Resource Smart upgrades to existing BC Hydro hydroelectric facilities and the Waneta Transaction.[10]

Average energy capability is calculated based upon the maximum amount of annual energy that the Heritage hydroelectric assets can produce under average water conditions.[11]

BC Hydro's Heritage hydro FELCC is approximately 44,100 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 11,500 MW in F2017, 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 Clean Energy Act Self-Sufficiency Requirements

Pursuant to subsection 6(2) of the *CEA*, BC Hydro is required to achieve electricity self-sufficiency by the year 2016 (i.e., F2017), by holding the rights to an amount of electricity that meets its electricity supply obligations under average water conditions from its Heritage assets that are hydroelectric facilities, taking into account DSM and electricity solely from electricity generating facilities within the Province. As discussed above, to support this determination, the Heritage hydro energy capability is defined in the Electricity Self-Sufficiency Regulation as the capability under average water conditions.

As a result of self-sufficiency requirements set out above:

[10] The Waneta Transaction refers to BC Hydro's purchase of a one third interest in the Waneta hydroelectric facility . 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.

[11] 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".

- The Canadian Entitlement (**CE**), the Canadian portion of the additional electricity produced in the Columbia River in the western U.S., as a result of provisions in the Columbia River Treaty, is not included in the IRP LRBs, other than as a contingency or potential short-term bridging resource, because it is not generated “solely from electricity facilities within the Province”. This is also 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”.[12]
- The historic 2,500 GWh/year of Heritage non-firm energy/market allowance becomes 4,100 GWh/year in F2017 and beyond
- The 400 MW of market reliance is 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 considered 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[13] 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).

[12] BCUC Decision on Revelstoke Unit 5 CPCN dated July 12, 2007.
[13] Non-firm Heritage hydro energy is any energy that is produced by the system in excess of that available during critical water conditions.

The studies for assessing the FELCC and average energy capability 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 available[14] 60-year historic water inflow record from October 1940 through September 2000, which is assumed to represent the range of inflows that may occur in the future. FELCC is determined using the critical low water period (1942 to 1946) within the 60-year record. Average annual energy is determined using the entire 60-year record.

Average water capability can and does change over time with load shape changes, resource addition(s) or retirement(s), Columbia River 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 impacts the dispatch of the Heritage hydro system, and hence the FELCC and average annual energy.

In November 2003, through the *BC Hydro Public Power and Legacy and Heritage Contract Act,*[15] 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 10 (issued in June 2007) and has been used in the 2004 Integrated Electricity Plan (**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

[14] The 10-year historic water inflow record from October 2000 to September 2010 was not available at the time of the critical period and long-term system capability studies.

[15] S.B.C. 2003, c.86.

studies have estimated that the Heritage hydro system FELCC is about 44,100 GWh/year and the average annual energy is about 48,200 GWh/year in F2017, with the additions of Mica Units 5 and 6 and additional Resource Smart projects. Some of the primary contributors to the system capability increases since the last formal study in 2003 include:

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

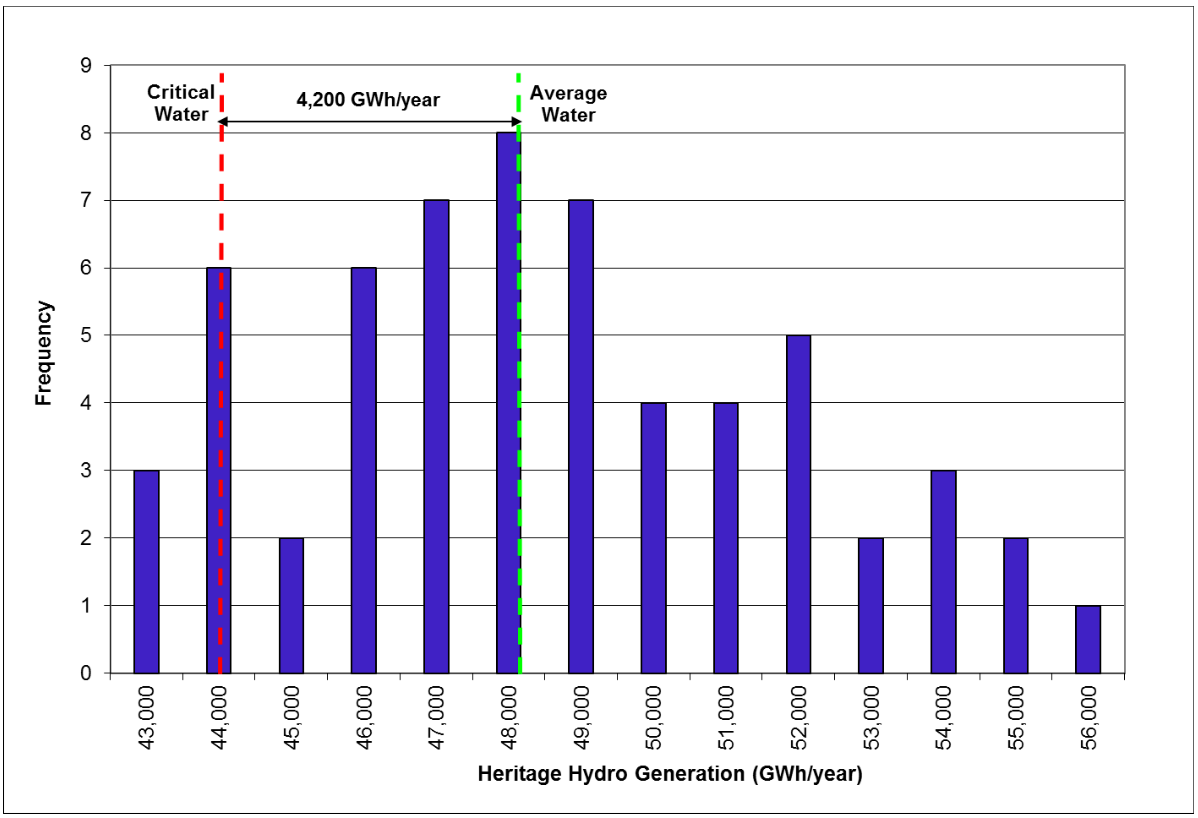
(b) Existing and committed Heritage resource additions and retirements:
   - (i) Waneta Transaction
   - (ii) GM Shrum (**GMS**) G1-5 and G9-10 turbine upgrades
   - (iii) GMS G6-8 turbine and generator upgrades
   - (iv) Unit upgrades at Stave Falls, Bridge River, Cheakamus and Aberfeldie
   - (v) Additions of Revelstoke Unit 5, and Mica Units 5 and 6
   - (vi) Decommissioning of the Heber Diversion
   - (vii) Removal of Burrard Thermal Generating Station (**Burrard**) pursuant to the *CEA*

(c) Inflow updates
   - (i) A recent BC Hydro engineering study improved the quality and confidence in the Peace River stream flow data

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.

Figure 2-5 Frequency Distribution of Heritage Hydro Generation



In addition, in any given year, there is non-firm energy from existing and committed IPP resources. 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 2,100 GWh/year of additional non-firm energy potential from IPPs.

BC Hydro and/or its 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 WECC and other select regions in North America
- Optimize the purchase and sale of electricity and natural gas in relation to BC Hydro's capabilities and domestic requirements

By planning an electric system where we generally have more energy available than is needed to meet our customer requirements 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. Further information on market assessments, including changing market conditions, can be found in Chapter 5.

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 Columbia River Treaty storage projects, Canada receives an entitlement to one-half of the downstream power benefits (i.e., Canadian Entitlement), 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 Columbia River Treaty is terminated. The Province is leading the Columbia River Treaty 2014 review process. This review will have no impact on the Canadian Entitlement before 2024. The post-2024 impact is under study and will not be defined within the IRP timeframe. Since Canadian Entitlement 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.

2.3.1.5 Resource Smart Projects

Projects that have already been completed, such as Revelstoke Unit 5 and the turbine upgrades at Cheakamus and Aberfeldie Redevelopment, have been included in the Heritage hydro value shown in the LRB tables in Appendix 8A. Recent existing and committed Resource Smart projects at GMS Units 1 to 8[16] are shown as incremental supply to the Heritage hydro values shown in the LRB.

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. On February 8, 2013, the John Hart Replacement Project was granted a CPCN from the BCUC and is also now a committed resource in the LRB.

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 southeastern B.C., from Teck Metals Ltd. BC Hydro’s one-third interest in 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

[16] Turbine upgrades on GMS Units 1-5 and capacity increases on GMS Units 6-8.

(**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.[17]

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 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 involve 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

Burrard and Prince Rupert Generating Station are the only two BC Hydro-owned thermal (natural gas-fired) generating stations that serve the integrated system. The third BC Hydro-owned natural gas-fired generating station, Fort Nelson Generating Station (**FNG**), is discussed in section 2.5.2.

[17] The Waneta Transaction was negotiated based on the assumption that the WEP would proceed with an in-service date (**ISD**) of April 1, 2014. Because of the WEPs 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

Burrard's firm energy contribution is 0 GWh/year as a result of subsections 3(5), 6(2)(d) and 13 of the *CEA,* except by regulation. Burrard is not available for use in meeting self-sufficiency requirements but continues to be available in accordance with the *CEA* for emergency backup purposes. 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 as follows: 900 MW in F2014; 450 MW in F2015; and 0 MW in F2016.

2.3.2.2 Prince Rupert Generating Station

Prince Rupert Generating Station's firm energy and ELCC contributions are 180 GWh/year and 46 MW respectively.

2.3.3 Existing and Committed IPP Supply

BC Hydro is forecast to have the rights to approximately 14,450 GWh/year of firm energy and 1,300 MW of ELCC[18] 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 Call Phase 1 and Phase 2 Request for Proposals, the IPO, the Standing Offer Program (**SOP**), WEP, 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 LRBs 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

[18] Before reserve requirements.

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 next 7,500 GWh/year of run-of-river IPP projects identified in the 2013 Resource Options Report (**ROR**) Update (attached as Appendix 3A-1), BC Hydro estimates that it can rely on approximately 78 per cent of average energy as firm energy. However, if BC Hydro were to add more run-of-river projects beyond that amount, the ability to absorb residual non-firm energy may become increasingly difficult as the markets are significantly over-supplied in the freshet. This also has potential cost impacts. More details on the firm energy assessment can be found in Appendix 3C.

2.3.3.1 Pre-Bioenergy Call Phase 1 Resources

As of Spring 2013, BC Hydro has 74 EPAs with IPPs that were signed through acquisition processes initiated prior to the Bioenergy Phase 1 Call, with 12 of the associated projects not yet in commercial operation. The largest power acquisition process was the F2006 Open Call for Power (**F2006 Call**). In F2017, BC Hydro forecasts it will rely on about 8,500 GWh/year of firm energy and 800 MW of ELCC, post-attrition, from these IPPs.

2.3.3.2 Bioenergy Call – Phases 1 and 2

Guided by the policy actions and directions contained in the 2007 BC Energy Plan, the 2008 B.C. Bioenergy Strategy and the *CEA*, BC Hydro 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 – 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 600 GWh/year and 70 MW by F2017 post-attrition.

- Bioenergy Phase 2 Call – In August 2011, BC Hydro announced the selection of four projects for the award of EPAs. Pursuant to subsection 7(1)(e) of the *CEA*, these EPAs are exempt from section 71 of the *UCA*. These resources are expected to provide approximately 600 GWh/year and 70 MW by F2017 post-attrition.

2.3.3.3 Clean Power Call

Upon the completion of the Clean Power Call in August 2010, BC Hydro had awarded 25 EPAs involving 27 projects, with an expected volume of approximately 2,300 GWh/year and 170 MW by F2017 post-attrition. The Clean Power Call EPAs are exempt from section 71 of the *UCA* pursuant to section 7(1)(g) of the *CEA*.

2.3.3.4 Integrated Power Offer

Under the IPO, BC Hydro targeted the acquisition of up to 1,200 GWh/year from pulp and paper customers that qualified for federal Green Transformation Program funding. Pursuant to subsection 7(1)(f) of the *CEA*, these EPAs are exempt from section 71 of the *UCA*. BC Hydro has signed seven EPAs with customers that are forecast to provide approximately 1,100 GWh/year and 170 MW by F2017 post-attrition.

2.3.3.5 AltaGas Projects – Northwest Transmission Line

BC Hydro has signed three EPAs with AltaGas Ltd. totalling approximately 900 GWh/year and 30 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 [19] on October 1, 2010, which accounts for approximately 300 GWh/year and 10 MW by F2016 post-attrition in the LRBs. WEP is exempt from section 71 of the *UCA* pursuant to the Columbia Power Corporation and the Columbia Basin Trust (**CPC/CBT**) Projects Exemption Continuation Regulation.[20]

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 subsection 15(2) of the *CEA*. The SOP was implemented to encourage the development of small and clean or renewable energy projects in BC Hydro's service area and to streamline the process for small developers selling electricity to BC Hydro. To date, BC Hydro has signed 11 SOP EPAs, which are expected to provide approximately 200 GWh/year and 10 MW by F2017 post-attrition. Pursuant to subsection 7(1)(h) of the *CEA*, these EPAs are exempt from section 71 of the *UCA*. BC Hydro considers incremental actions and future volumes under the SOP in Chapter 4.

2.3.3.8 Distributed Generation and Net Metering

BC Hydro continues to examine the potential for increased Distributed Generation (**DG**) across its customer base. Note that the Net Metering tariff, aimed at residential and commercial customers wishing to connect a small generating unit (currently up to 50 kW) from a clean or renewable energy source to BC Hydro's distribution system, is considered as DG. Given the small contributions from the Net Metering tariff, it has not been included in the LRBs. In general, Distributed Generation has not been included as a separate category in the LRBs, however BC Hydro notes that DG projects are incorporated in some of the programs/offers that are included in the

[19] The Waneta Expansion Limited Partnership is between Fortis Inc., Columbia Power Corporation and the Columbia Basin Trust.

[20] B.C. Reg. 254/2010.

LRBs, for example the 2002 Customer Based-Generation Call and the 2010 Community-Based Biomass Call.

2.3.3.9 EPA Renewal Assumptions for IPP Resources

Prior to this IRP, BC Hydro treated EPA renewals as committed resources, and assumed that all EPAs would be renewed with the exception of biomass-related EPAs, which were assumed to not be available after EPA expiry due to fuel risk. BC Hydro reviewed this treatment, and given its LRBs and the price and availability issues, has decided that it is not appropriate to treat EPA renewals as a 'given' and thus a committed resource. In particular, BC Hydro is of the view that potential EPA renewals should be treated as any other viable future resource to meet the energy and capacity LRBs set out in this chapter. EPA renewals must be considered with other alternatives to meet the forecasted load, balancing considerations of cost, risk, uncertainty, supply reliability/deliverability and Provincial Government energy objectives.

BC Hydro removed EPA renewals (of about 1,200 GWh/year and about 150 MW in F2017) from the energy and capacity LRBs. BC Hydro analyzes EPA renewal potential in section 4.2.

2.3.4 ELCC from Existing and Committed Resources

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

Table 2-5 ELCC in F2017

			Megawatts (MW) in F2017
Existing and Committed Supply			
	Heritage Hydroelectric		10,072
	Heritage Thermal		46
	Resource Smart		51
	Existing IPP Purchase Contracts (excluding Rio Tinto Alcan EPA)		547
	F2006 Call		86
	Standing Offer Program (signed EPAs)		11
	Bioenergy Call Phase I		68
	Waneta Transaction		249
	Clean Power Call		166
	AltaGas Power (NTL) (signed EPAs)		31
	Mica Unit 5		465
	Mica Unit 6		460
	Waneta Expansion Project		10
	IPO (signed EPAs)		165
	Bioenergy Call Phase 2		65
	Ruskin Upgrade Project		76
	Conifex EPA		21
	John Hart Replacement Project		127
	Sub-total	(a)	12,714
	Supply Requiring Reserves	**(a)**	**12,714**
Reserves			
	14 per cent of Supply Requiring Reserves		1,780
	Minus: 400 MW market reliance		n/a
	Sub-total	(b)	1,780
Supply Not Requiring Reserves			
	Rio Tinto Alcan 2007 EPA	(c)	153
Total Effective Load Carrying Capability		**(d) = a – b + c**	**11,088**

* Numbers may not add due to rounding.

2.3.5 Energy from Existing and Committed 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

		Gigawatt Hours (GWh) in F2017
Existing and Committed Supply		
	Heritage Hydroelectric	42,425
	Heritage Thermal	180
	Resource Smart	133
	Existing IPP Purchase Contracts (excluding Rio Tinto Alcan EPA)	5,494
	Rio Tinto Alcan 2007 EPA	442
	F2006 Call	2,333
	Standing Offer Program (signed EPAs)	201
	Bioenergy Call Phase I	585
	Waneta Transaction	865
	Clean Power Call	2,258
	AltaGas Power (NTL) (signed EPAs)	947
	Mica Units 5 and 6	201
	Waneta Expansion	306
	Integrated Power Offer (signed EPAs)	1,139
	Bioenergy Call Phase 2	565
	Ruskin Upgrade Project	221
	Conifex EPA	180
	John Hart Replacement Project[21]	300
	Sub-total (a)	58,775
Additional Non-Firm Energy Supply		
	Heritage Non-Firm/Market Allowance	4,100
	Sub-total (b)	4,100
Total Supply	**(c) = a + b**	**62,875**

[21] John Hart is planned to provide about 835 GWh/year of average energy and 127 MW of ELCC post-completion in F2018; the F2017 figure reflects the reduced energy amount expected during construction.

2.4 System Load-Resource Balances

The purpose of the LRBs is to define the future need for resources by comparing the mid 2012 Load Forecast for the 20-year study period of the IRP with the annual capability of BC Hydro's existing and committed resources. This is done with respect to two views of the system – the energy LRB[22] and the capacity LRB. As described in section 2.2, BC Hydro has prepared the LRB with and without the expected load from LNG. Load scenarios with additional LNG, mining and oil and gas sector loads are incremental to the base LRBs and are described in section 2.5.

The LRBs in this section are presented without showing the current DSM Plan targets set out in the 2008 LTAP Evidentiary Update[23], because incremental DSM actions must be considered against and with other supply alternatives to meet the forecasted load, balancing considerations of cost, risk, uncertainty, supply reliability/deliverability and Provincial Government energy objectives. Further analysis on future reliance on DSM is set out in section 4.3 and section 6.3.

The detailed energy and capacity LRB tables are provided in Appendix 8A. In the following sections, the discussion and presentation of the 2012 Load Forecast and surplus/deficit values will include the Expected LNG load unless otherwise stated.

[22] BC Hydro prepares a 20-year view of the LRBs which is used to determine future long-term DSM and supply-side resource requirements given the physical capability of the system using firm energy in the planning horizon (F2017 to F2033). The operational horizon (F2014-F2016) provides the forecasted optimal reliance on existing resources in the short term given near-term market conditions, system constraints, planned outages and inflows.

[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 2012 Load Forecast, the incremental target is reduced to approximately 7,800 GWh/year and 1,400 MW of savings by F2021.

2.4.1 BC Hydro's Load-Resource Balances

BC Hydro analyzed the future load requirement with both the mid load forecast without LNG and with incremental load from the Expected LNG. The energy LRB in Figure 2-6 shows that for the 2012 mid Load Forecast, BC Hydro will have sufficient energy resources until F2017[24] with or without the Expected LNG load. Based on the 2012 Load Forecast and existing and committed resources before DSM, the energy LRB in Figure 2-6 and Table 2-7 shows resource deficits of 363 GWh/year in F2017; 15,660 GWh/year in F2023; and 26,634 GWh/year in F2033. Chapter 6 contains the results of the IRP analysis based on the trade-offs between different resource options to address these long-term energy deficits and Chapter 8 summarizes BC Hydro's plan to acquire sufficient energy resources to eliminate these energy deficits.

[24] BC Hydro has only considered the requirements for additional resources in the planning horizon of F2017 to F2033. Operational shortfalls shown in F2014 through F2017 may be met through conservation, economic market purchases, greater use of natural gas-fired (thermal) generation resources or greater drawdown of major reservoirs.

Figure 2-6 Energy Load-Resource Balance

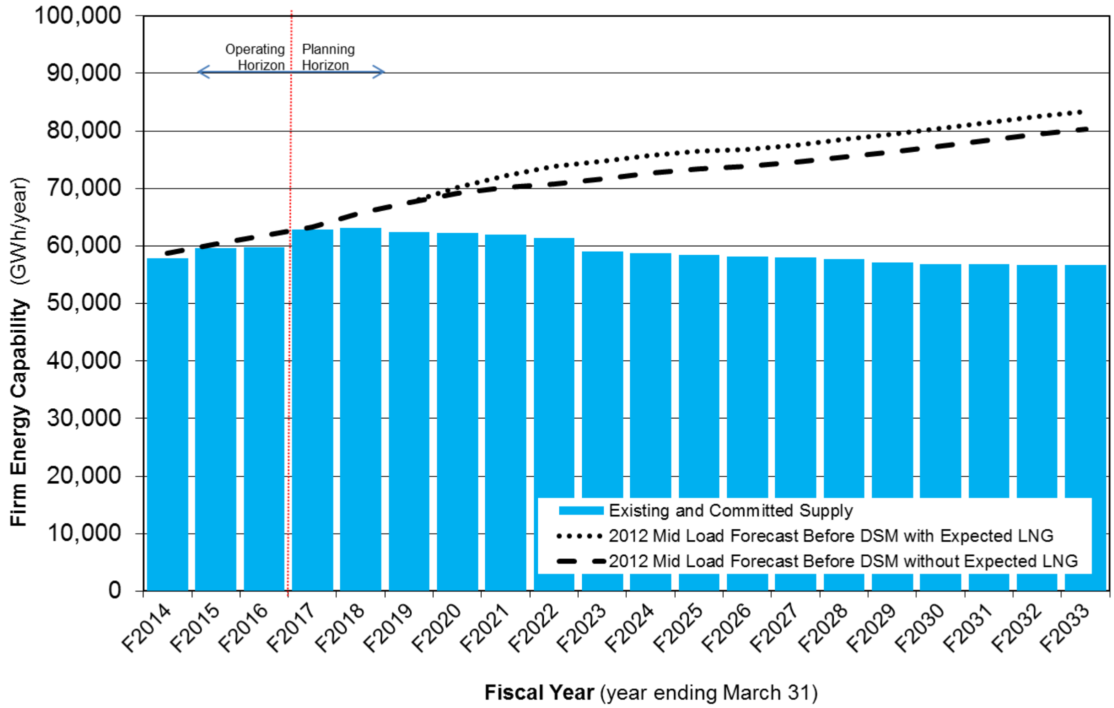


Table 2-7 Energy Surplus/Deficit (GWh)

	F2017	F2023	F2028	F2033
Surplus/Deficit with Expected LNG	-363	-15,660	-20,776	-26,634
Surplus/Deficit without Expected LNG	-363	-12,660	-17,776	-23,634

The capacity LRB compares the existing and committed ELCC to the 2012 Load Forecast system peak load before DSM, including reserve requirements.[25] Figure 2-7 shows that BC Hydro has a capacity gap of about 600 MW in F2017. The capacity LRB shown in Figure 2-7 and Table 2-8 identifies resource deficits of 594 MW in F2017; 2,646 MW in F2023; and 4,737 MW in F2033. Chapter 8 summarizes BC Hydro's plan to acquire sufficient capacity resources to eliminate these capacity deficits.

[25] Reserve requirements included in peak loads presented in section 2.2 where indicated.

Figure 2-7 Capacity Load-Resource Balance

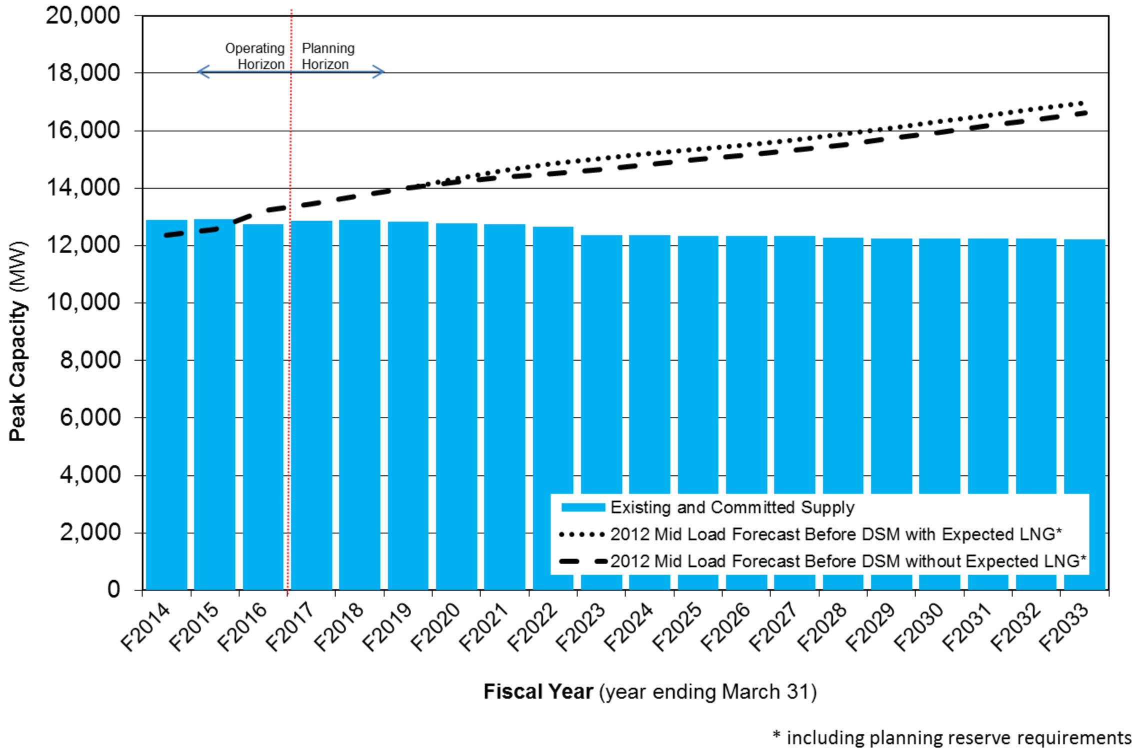


Table 2-8 Capacity Surplus/Deficit (MW)

	F2017	F2023	F2028	F2033
Surplus/Deficit	-594	-2,646	-3,599	-4,737
Surplus/Deficit without Expected LNG	-594	-2,285	-3,239	-4,377

The detailed information supporting Figure 2-6, Figure 2-7, Table 2-7 and Table 2-8 can be found in Appendix 8A.

2.4.2 Load-Resource Balance Road Map

LRBs are used throughout the IRP to indicate the need for new resources and to highlight the impacts that adding resources can make. The LRBs show the following transitions through the chapters:

- Chapter 2 – as described above, the LRBs in section 2.4 demonstrate the need for new energy and capacity resources without incremental DSM, IPP renewals and new IPPs which are not committed resources
- Chapter 4 – shows LRBs inclusive of typical or expected acquisitions including certain EPA renewals and continuing with the current DSM target. The LRBs shown in section 4.2.1 highlight the LRB gap prior to considering actions to managing costs in the short term while the LRBs in section 4.2.6 show the LRBs after considering those actions.
- Chapter 6 – starts with the LRBs concluded in Chapter 4 after short-term supply management actions and then assesses the need for longer-term resources including whether to modify the current DSM target
- Chapter 8 – concludes with the resulting LRBs in sections 8.2.10, 8.3.5 and 8.4.6 that would result if the Recommended Actions are undertaken under BRP and CRP conditions, respectively

For further clarity, the LRBs in Chapter 4 review the need and benefits of short-term cost management actions in the following steps:

1. The LRBs in section 4.2.1 include those incremental resources (see Table 4-1) that BC Hydro would typically include in its resource stack for planning purposes to generate an illustrative example for these “typical” resource planning assumptions. For example, while the analysis in Chapter 6 determines the overall level of DSM (e.g., between DSM Options 1, 2 and 3), the LRBs in section 4.2.1 use the Option 2/DSM target for this illustrative purpose. The resulting LRBs demonstrate that there is an opportunity to undertake the prudent cost-management measures to optimize BC Hydro’s portfolio of energy resources over the short to mid-term which are described in section 4.2.5.

2. The LRBs in section 4.2.6 demonstrate the cumulative impact of implementing all of the proposed changes to energy and capacity over the planning horizon from section 4.2.5. In particular these LRBs contain the following incremental resources: (1) an assumed number of EPA renewals; (2) modifications to the SOP; (3) deferral, downsizing and termination of some pre-COD EPAs**;** and (4) short-term modifications to the Option 2/DSM target.

2.5 Regional Load-Resource Balances

The IRP is primarily focused on planning resources from a province-wide, integrated system perspective. To the extent there are significant regional constraints, particularly those that have potential impacts on the bulk transmission system, such constraints are also addressed in this IRP. Regional planning issues addressed in this IRP include the following:

- Regions facing potential large industrial load growth. As described in section 2.2.2, these include the North Coast, Fort Nelson/HRB and South Peace regions.
- Large urban regions characterized by a significant disparity between supply and demand. These regions include the Lower Mainland and Vancouver Island regions.

With respect to regional requirements, BC Hydro examines the LRB on a peak demand basis. The peak load in a region can be met by either local supply resources or power transmitted from other regions in BC Hydro's service area by the bulk transmission system. As a result, transmission transfer capabilities are an important planning consideration when examining regional LRBs and triggering the need for new resources even when the system-based analysis shows no deficit.

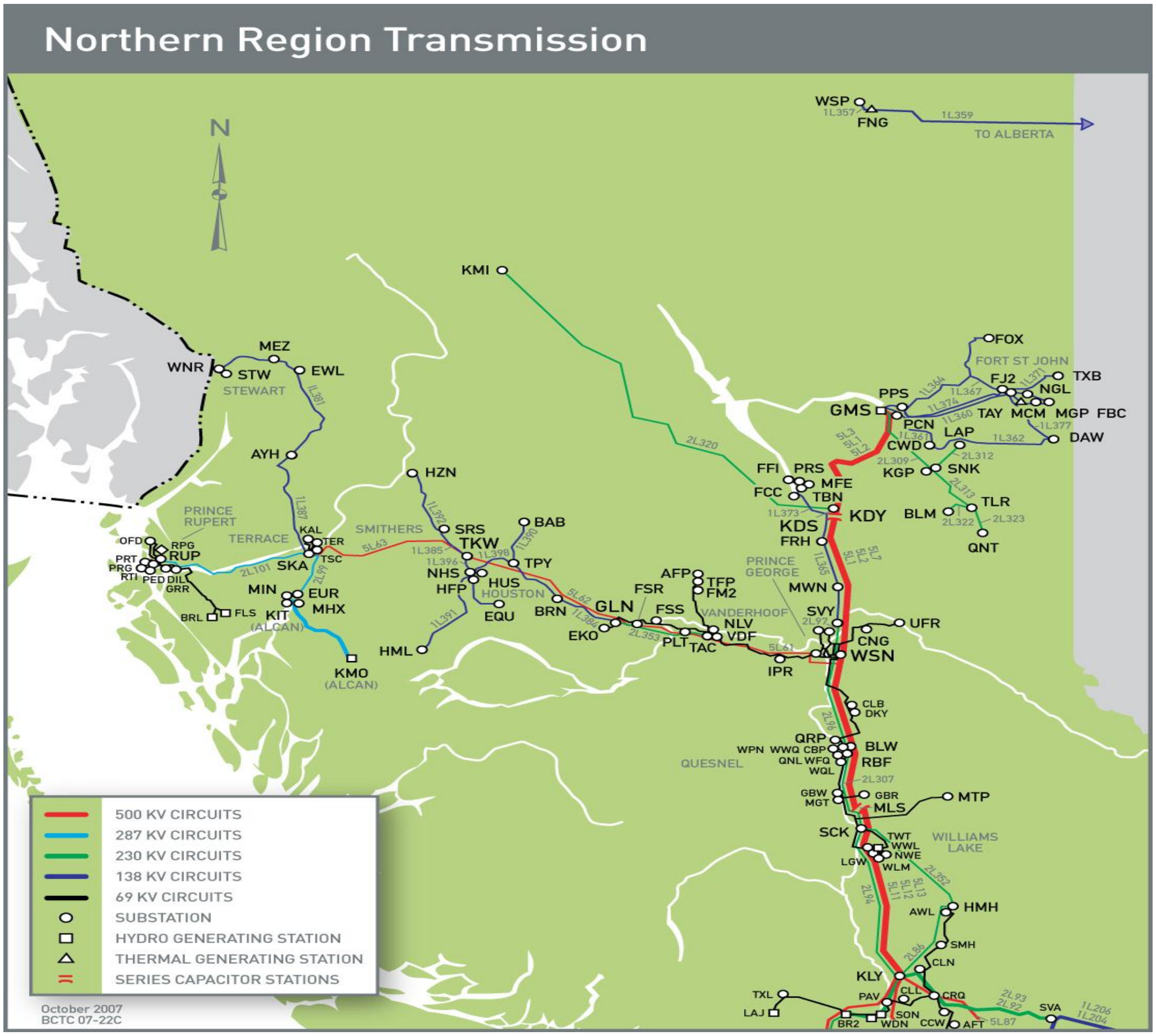
For transmission planning purposes, BC Hydro defines transmission capability from a system reliability perspective. In its simplest form, this is based on a deterministic planning criteria that primarily considers normal (N-0, non-firm) and single contingency (N-1, firm) system conditions. From a transmission planning reliability perspective a single, radial line does not provide N-1, firm transmission capability. BC Hydro generally plans its non-radial transmission system using N-1, firm transmission capability and its single, radial transmission lines using N-0, non-firm transmission capability.

2.5.1 North Coast

The North Coast region of BC Hydro's integrated system shown in Figure 2-8 is the area west of Williston substation (**WSN**) in Prince George. The primary source of electricity supply in the region is transmission, which consists of a single radial line from Prince George to Terrace that is made up of three 500 kV circuits: 5L61 from WSN to Glenannan substation (**GLN**), 5L62 from GLN to Telkwa substation (**TKW**) and 5L63 from TKW to Skeena substation (**SKA**).

As described above, BC Hydro's transmission reliability planning criteria require planning to an N-0 transmission capacity on radial lines such as that serving the North Coast region. The key sub-regions of interest in the North Coast due to a potential increase in LNG and mining activities are the Bob Quinn Lake, Prince Rupert and Kitimat regions.

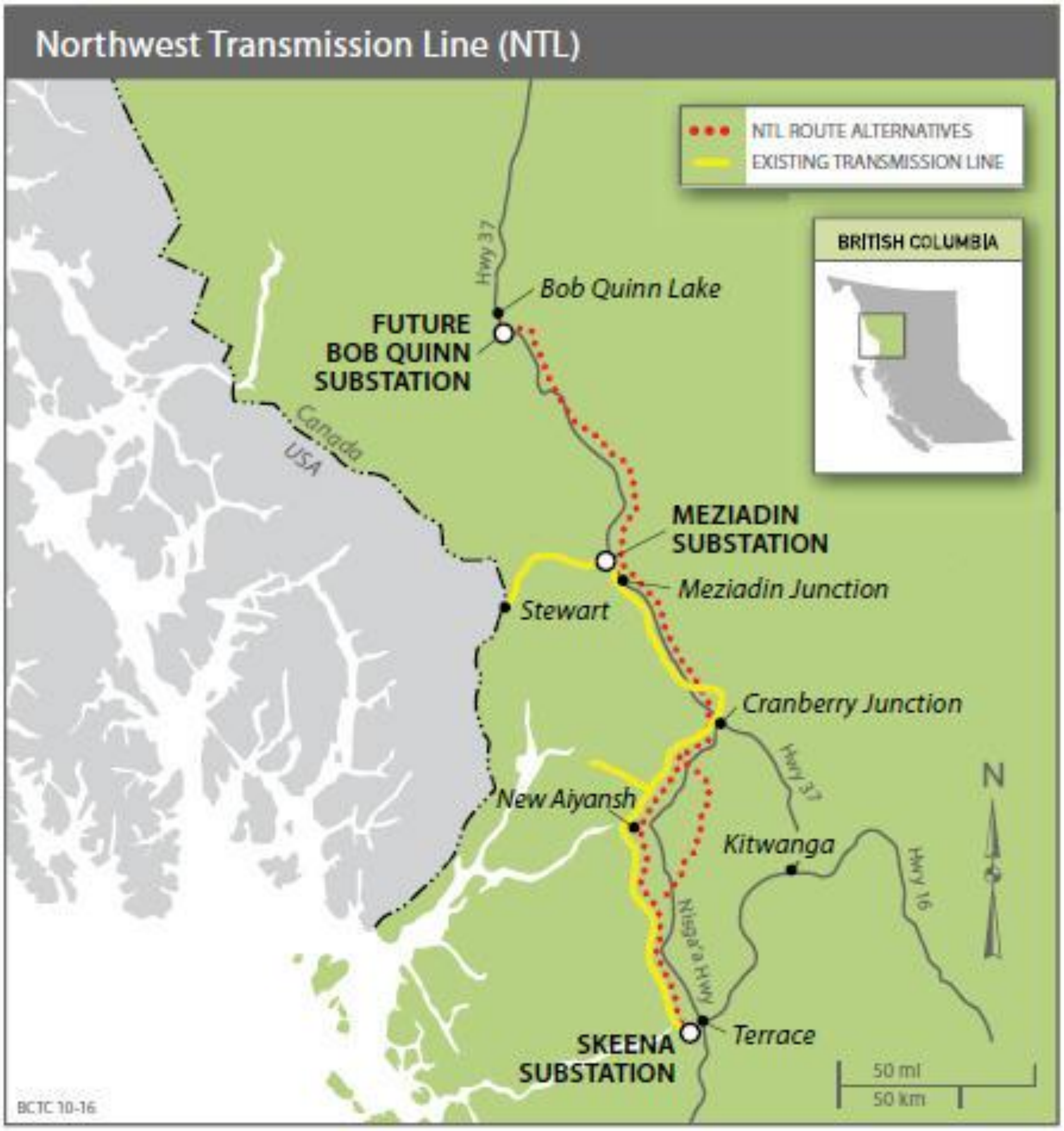
Figure 2-8 North Coast Transmission System



NTL is shown in Figure 2-9. It includes the construction of a new 287 kV, 344 km circuit extending from SKA near Terrace to Meziadin Junction, and north to a new substation to be located near Bob Quinn Lake. NTL will provide an interconnection point for clean or renewable generation projects (including the AltaGas projects referenced in section 2.3.3.5) and a reliable supply of clean or renewable 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 BC Hydro was granted an

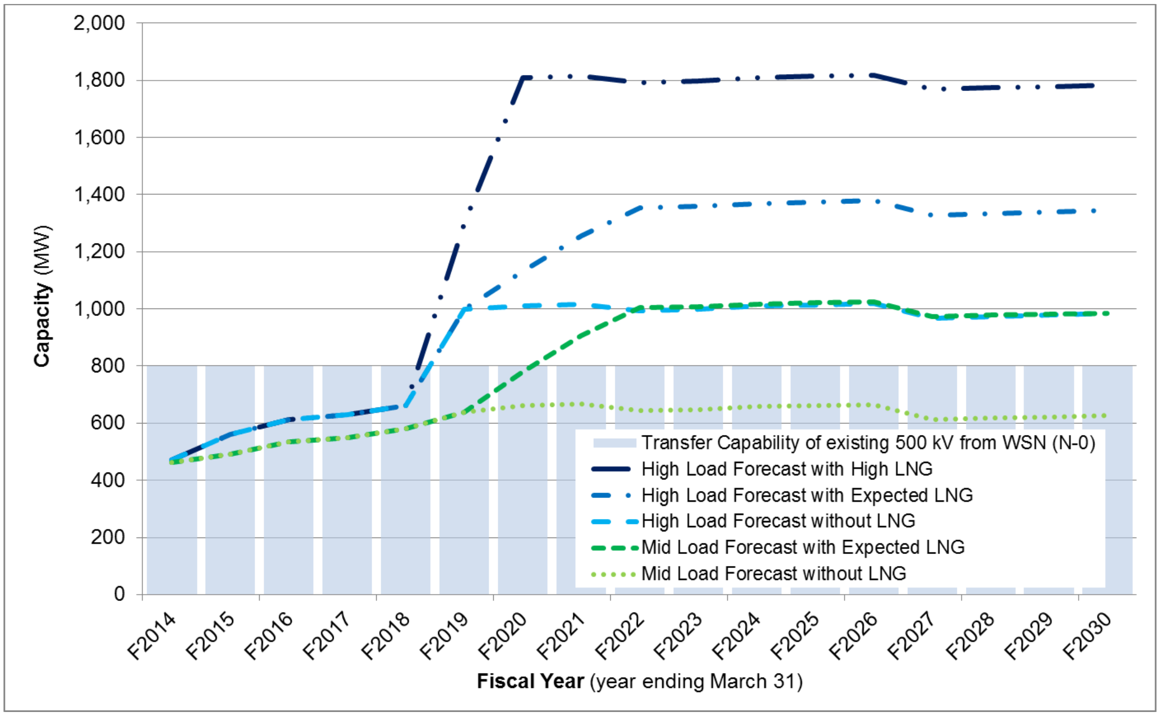
Environmental Assessment Certificate for NTL. The expected ISD of NTL is May 2014.

Figure 2-9 Northwest Transmission Line



As described in section 2.2, BC Hydro considered 360 MW of Expected LNG load that could occur in the North Coast region. In addition there is potential for significant mining activity, particularly around NTL (currently under construction). The regional LRB in Figure 2-10 shows that the N-0, non-firm transfer capability of the existing radial transmission system[26] could be exceeded under a number of LNG and mining scenarios.

Figure 2-10 North Coast Load-Resource Balance



For BC Hydro's analysis of the options to address the requirements in the North Coast region, please refer to section 6.5.

2.5.2 Fort Nelson and Horn River Basin

This IRP assesses various options for supplying the Fort Nelson and HRB regions under a range of HRB electrification scenarios. LRBs for these scenarios are presented below.

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

[26] From WSN.

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.

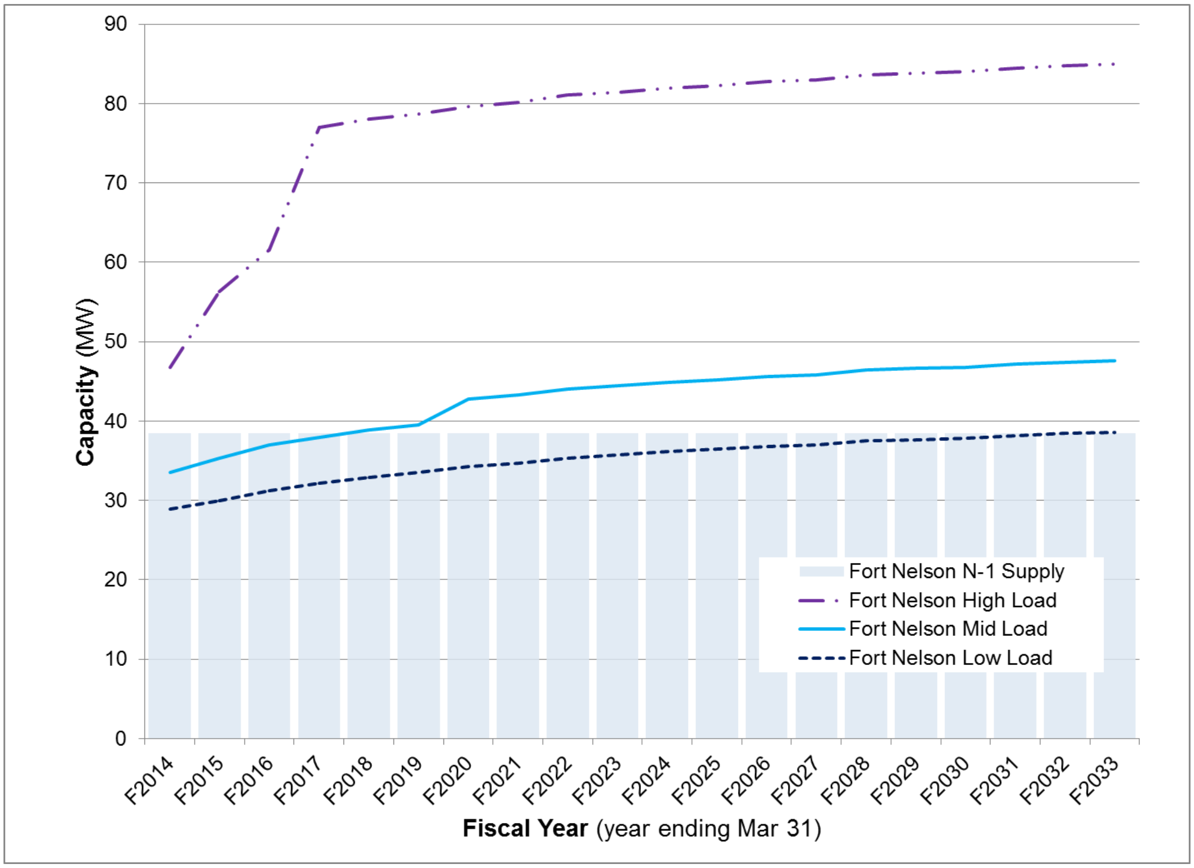
BC Hydro serves customers in the Fort Nelson region with electricity generated at its recently upgraded (47 MW to 73 MW) FNG and transmission service (38.5 MW) from Alberta. With these two resources, BC Hydro can currently meet its single contingency (N-1)[27] reliability criterion, such that when one of element is out of service, the entire Fort Nelson region load can still be served.

Figure 2-11 shows the load in the Fort Nelson region (not including potential HRB shale gas-related load) is expected to grow from its current level of about 30 MW to between 43 MW (mid forecast) and 80 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 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 event. Fort Nelson load is expected to remain relatively flat under the low load scenario.

In the mid load scenario, the load is expected to grow from its current level of about 30 MW (as measured by winter peak capacity) to about 43 MW by F2020 reaching the N-1 threshold for planning purposes by about F2018-F2019. While BC Hydro expects the load growth to be modest over the next five years (F2014-F2018), there are significant uncertainties to the forecast due to potential impacts from HRB development and/or other load developments such as a restart of currently shut-down forestry mills. These uncertainties could cause the capacity shortfall to occur earlier or later than F2018.

[27] 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.

Figure 2-11 Fort Nelson Region Load-Resource Balance



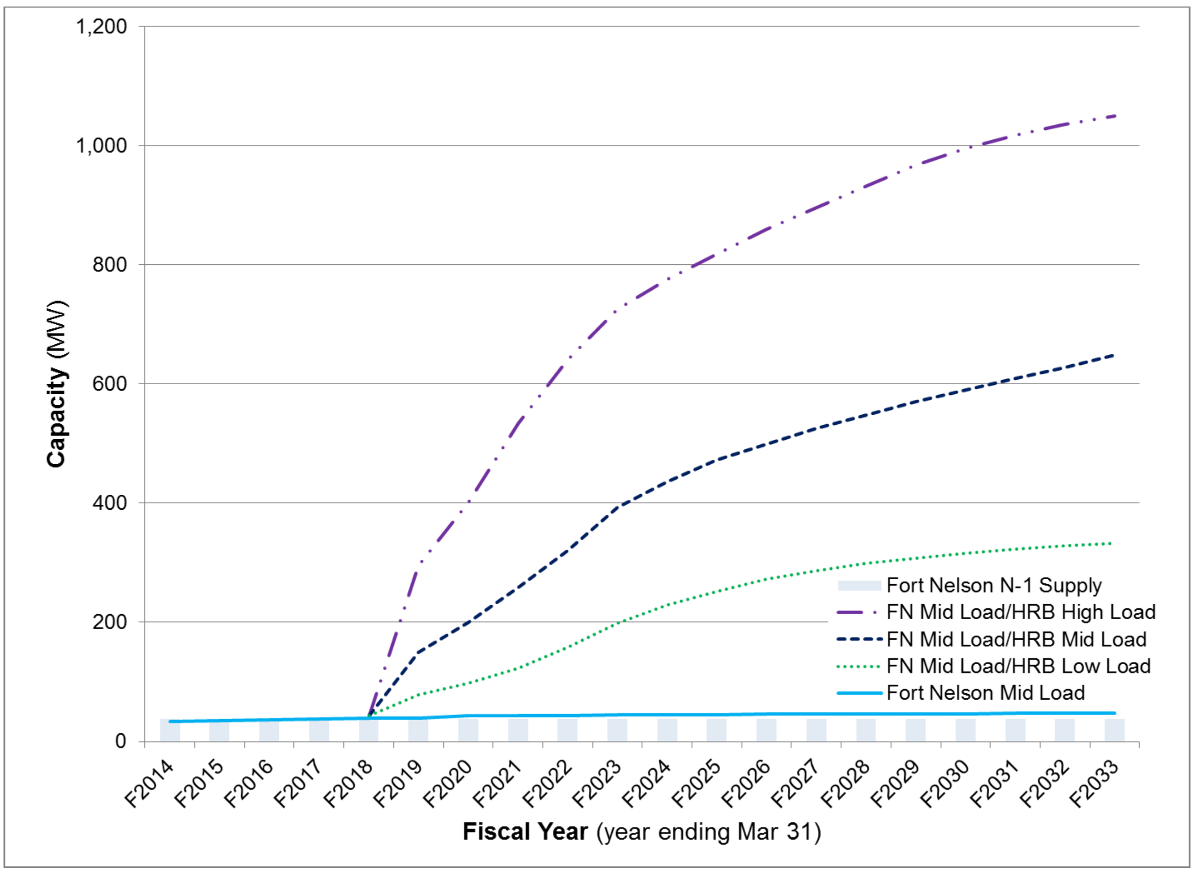
2.5.2.2 Horn River Basin

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 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 has not translated into applications for electricity service. However, issues such as climate change and GHG legislation may result in using electricity as a means of reducing the GHGs that result from the HRB shale gas production, processing and transportation.

Figure 2-12 shows the two HRB electric load scenarios (peak demand), along with the Fort Nelson mid peak demand (not including HRB electrification) and supply capability, that were developed for the IRP. In each case, it is assumed that BC Hydro continues to serve existing and new Fort Nelson load. A 20-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 350 MW of firm load-serving capability could be required by F2023, growing to approximately 600 MW by F2033.

Figure 2-12 Fort Nelson/HRB Regional Load Resource Balance

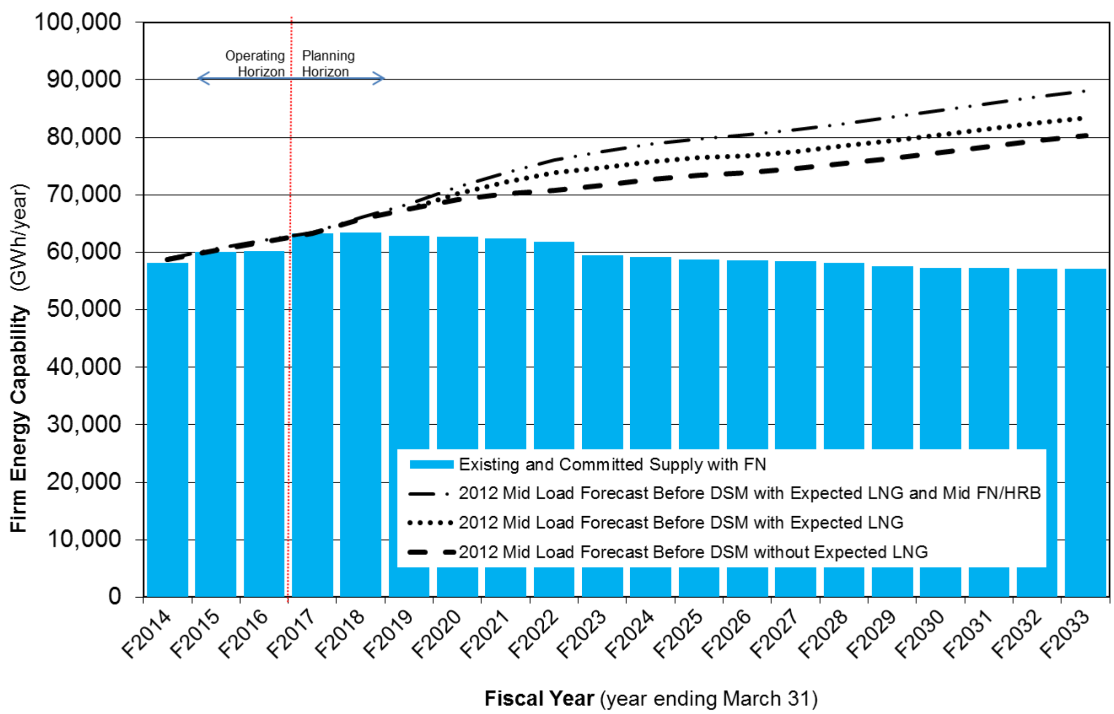


2.5.2.3 System LRB including Fort Nelson/HRB Load Scenario

One possible option is to supply both Fort Nelson and HRB regions with clean or renewable energy via a transmission line connected to BC Hydro's integrated system. BC Hydro has developed a system LRB that reflects such a future scenario to better understand the potential system requirements.

The system energy and capacity LRBs for a load forecast scenario that assumes an integrated Fort Nelson load and the electrification of the HRB are shown in Figure 2-13 and Figure 2-14. The resulting surplus/deficit amounts are shown in Table 2-9 and Table 2-10. The loads[28] in this scenario are about 2,800 GWh/year and 350 MW in F2023, growing to 4,700 GWh/year and 600 MW in F2033.

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



[28] The net requirements do not increase by this amount because FNG would provide approximately 430 GWh/year of energy and 73 MW of dependable capacity.

Table 2-9 Energy Surplus/Deficit with Fort Nelson and Horn River Basin Load Scenario (GWh)

	F2017	F2023	F2028	F2033
Surplus/Deficit with Fort Nelson and HRB	-169	-18,001	-24,285	-30,897

Figure 2-14 Capacity Load-Resource Balance with Fort Nelson and Horn River Basin

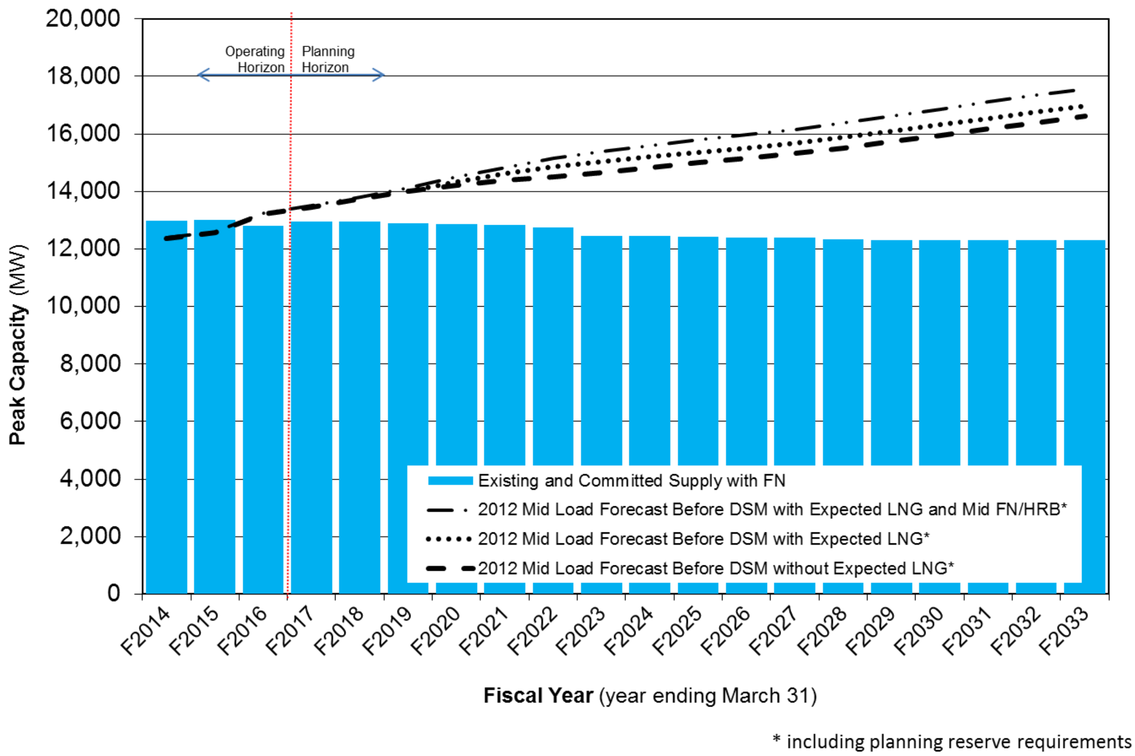


Table 2-10 Capacity Surplus/Deficit with Fort Nelson and HRB (MW)

	F2017	F2023	F2028	F2033
Surplus/Deficit with Fort Nelson and Horn River Basin	-570	-2,944	-4,045	-5,279

Additional information on the Fort Nelson/HRB scenarios and analysis is found in section 6.6 and Appendix 2E.

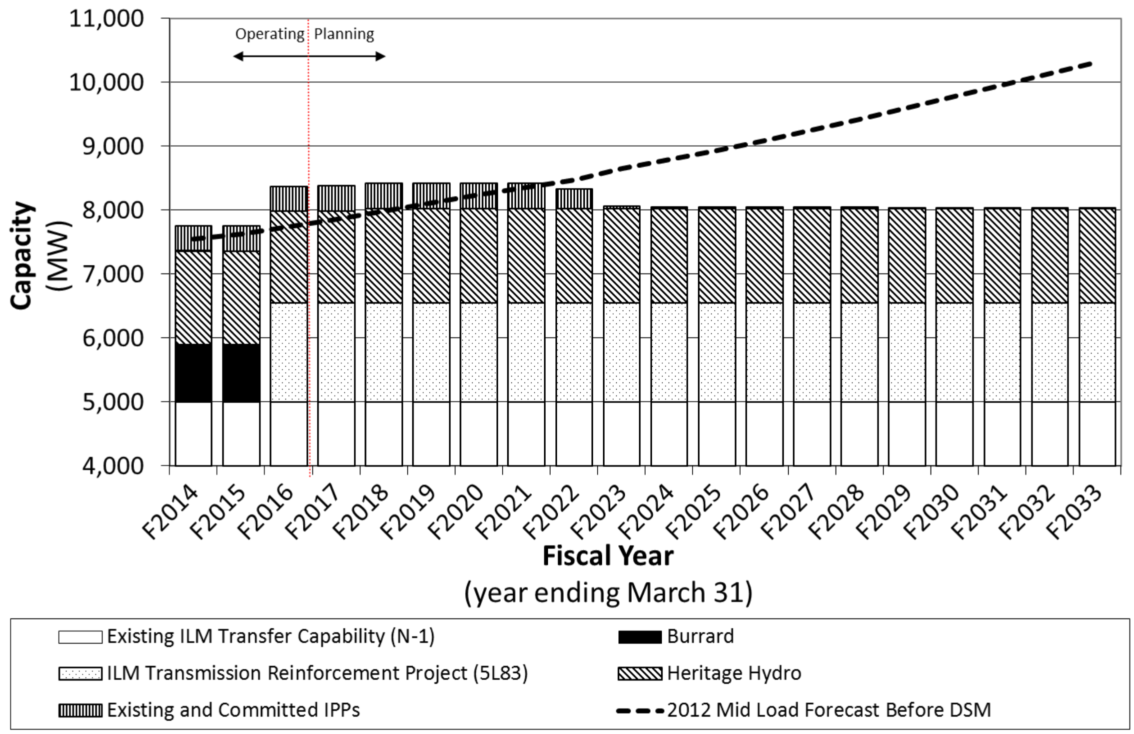
2.5.3 Coastal (Lower Mainland/Vancouver Island)

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 a second 500 kV transmission line (5L83) 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 2-15 and demonstrates that in the absence of incremental DSM or new or renewed dependable capacity supply in the Coastal region, new transmission transfer capability will be required in F2022. For BC Hydro's analysis of the options to address the requirements in the Coastal region refer to section 6.8.

Figure 2-15 Coastal (LM+VI) Load-Resource Balance

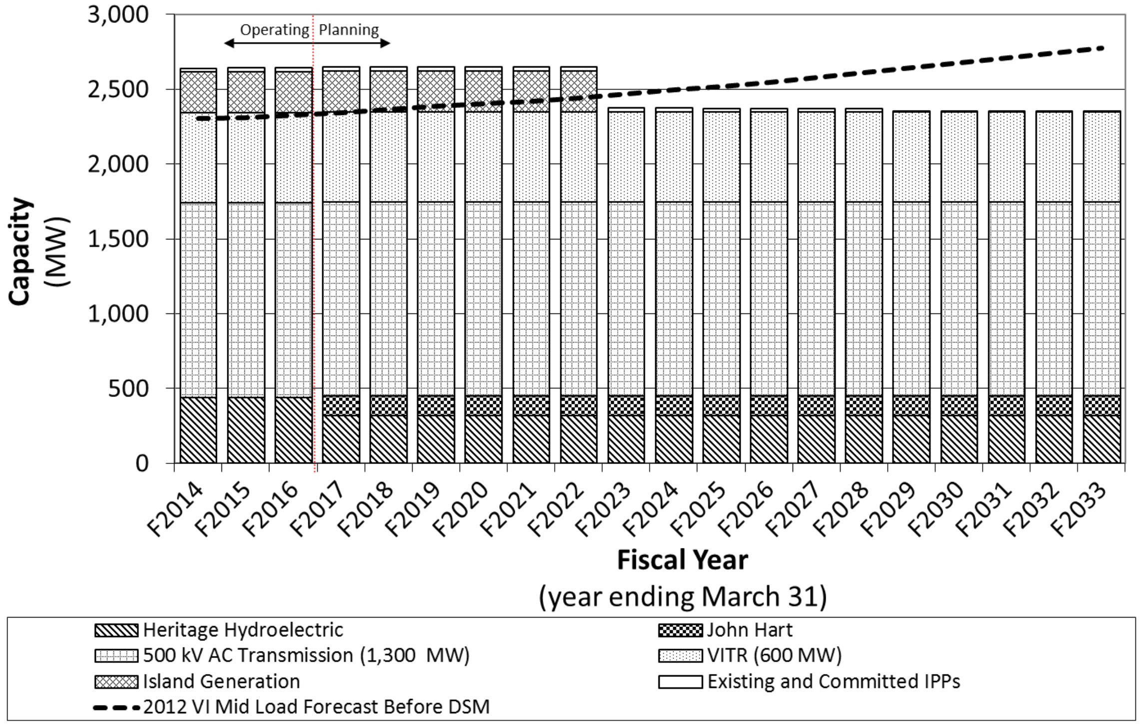


2.5.4 Vancouver Island

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 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 1,900 MW. Figure 2-16 shows that without incremental DSM, renewal of the EPA with Island Generation (gas-fired generator) or new on-island dependable capacity generation, new transmission upgrades between the Lower Mainland and Vancouver Island would be required in F2023. For BC Hydro's analysis of the options to address the requirements in the Vancouver Island region, refer to section 6.8.

Figure 2-16 Vancouver Island Load-Resource Balance

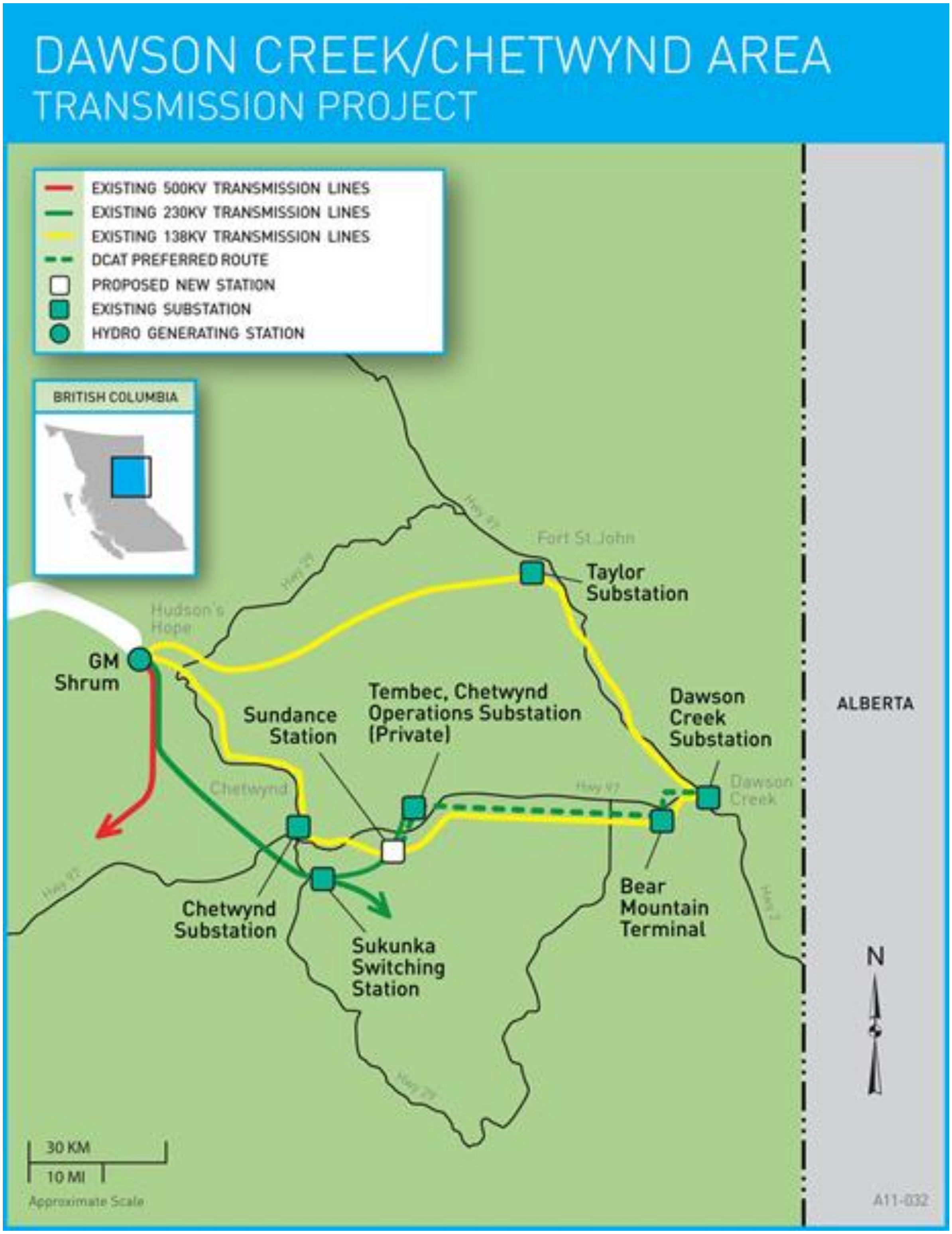


2.5.5 South Peace

BC Hydro's South Peace region is expected to experience continued significant load growth. While BC Hydro's DCAT project (illustrated in Figure 2-17) will increase some of the region's electricity supply capability, additional supply is likely to be required.[29]

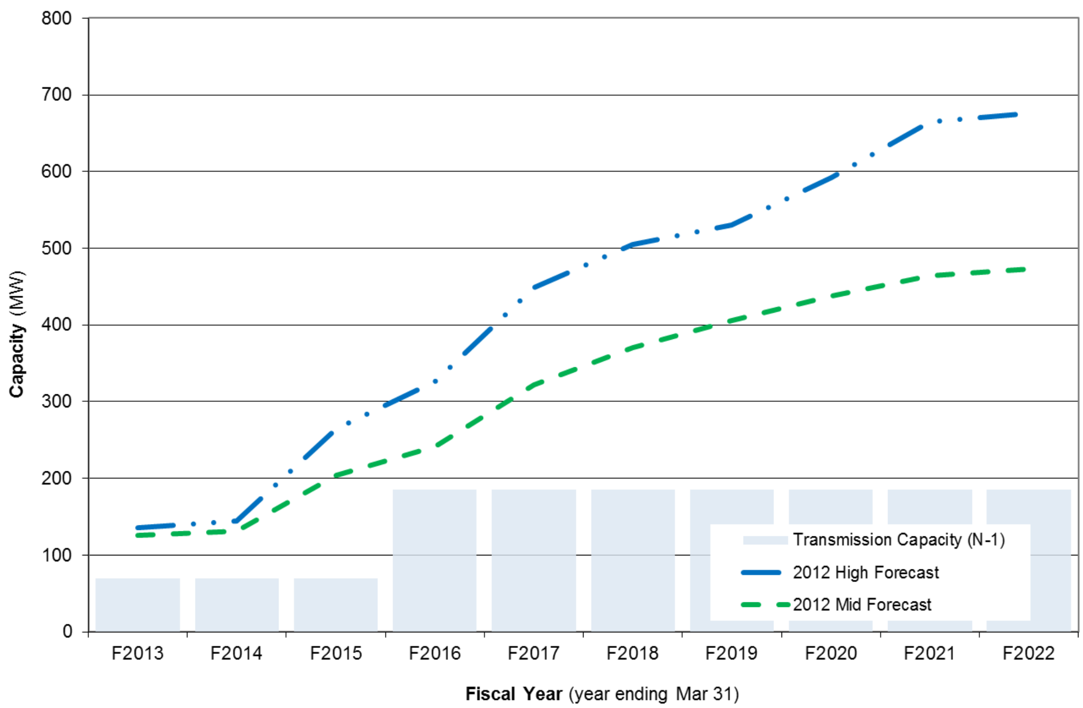
[29] A CPCN for DCAT was granted by the BCUC in April 2013 and the project is expected to be in-service by June 2015.

Figure 2-17 South Peace Region and DCAT Project



For illustrative purposes, Figure 2-18 shows the forecasted load growth in the Dawson Creek and Groundbirch sub-regions for both base and high load growth scenarios. This figure is indicative of the high demand for electricity in the broader South Peace region. This is largely due to natural gas exploration and development within the Montney shale gas basin. To meet the single contingency, N-1, firm reliability criterion additional transmission capacity or local generation is required immediately; to meet the N-0, non-firm reliability criterion, additional transmission capacity or local generation is required by F2019.

Figure 2-18 Dawson Creek / Groundbirch Load Resource Balance (MW)



BC Hydro continues to assess future electricity needs in the South Peace region and plans the regional transmission network accordingly. This planning work is known as the Peace Region Electric Supply study[30] and is considering the next phase of the regional capacity addition after the DCAT. BC Hydro's Recommended Action based on this study analysis is included in Chapter 8.

[30] Previously known as GDAT (GMS to Dawson Creek Area Transmission).