2008 Long Term Acquisition Plan

BC hydro

EVIDENTIARY UPDATE TO

APPENDIX N2

Fort Nelson Generating Station Upgrade

Introduction

This evidentiary update to sections of Appendix N2 of the 2008 Long-Term Acquisition Plan (**LTAP**) (Exhibit B-1-1) is to provide the latest information on the status of the Fort Nelson Generating Station Upgrade Project (**FNGU**). Table 1 is a concordance of the sections of Appendix N2 which are updated by this evidentiary update. If a section from Appendix N2 is not listed in Table 1, then it has not been updated as part of this evidentiary update. Section 2.10 ("Project Justification") of this evidentiary update is new and as a result does not replace a section of Appendix N2.

Table 1 Concordance Table

Appendix N2 Section being Replaced	Evidentiary Update Section
2.5.1 Project Overview	2.5.1 Project Overview
2.5.2 Environment and Social Impact Assessment	2.5.2 Environment and Social Impact Assessment
2.7 Other Applications and Approvals	2.7 Other Applications and Approvals
2.8.1 Introduction	2.8.1 Introduction
2.8.1.1 Pre-consultation	2.8.2 First Nations Consultation 2.8.3 Stakeholder Engagement
2.8.1.2 Identification of Stakeholders and First Nations	
2.8.1.3 Issues Identification	
	2.10 Project Justification
	2.10.1 Identification of Need
	2.10.2 Base Plan
	2.10.3 Alternatives to FNGU
	2.10.4 Implications of the Evidentiary Update

2.5 Project Description

2.5.1 Project Overview

The Fort Nelson Generating Station (**FNG**) is a natural gas-fired simple cycle gas turbine (**SCGT**) facility located 16 km south of the town of Fort Nelson (see Figure 2-2 of Appendix N2 for a transmission map of Fort Nelson and Northwestern Alberta). The 47 megawatts (**MW**) generating facility consists of a General Electric (**GE**) LM-6000 gas turbine directly coupled to a 47 MW Alstom generator, a once through steam generator (**OTSG**) style of heat recovery steam generator, and a water treatment plant to process the raw water supplied from the adjacent Spectra Energy natural gas processing plant (**Spectra**). Currently, only 60 per cent of the waste heat energy in the exhaust gases of the gas turbine is captured by the OTSG and used to generate steam. The remaining 40 per cent of the waste heat is exhausted to the atmosphere. Of the steam generated, 85 per cent is consumed when it is injected into the combustion chamber of the gas turbine to control nitrogen oxides (**NOx**) emission levels in the gas turbine flue gases. The remaining 15 per cent of the generated steam is used in a number of processes throughout the plant and is mostly condensed and reused. Figure 2-3 of Appendix N2 is a schematic of FNG in its current configuration.

2.5.1.1 *PROJECT DESIGN ALTERNATIVES*

FNG was designed and constructed to accommodate a combined cycle gas turbine (**CCGT**) configuration. BC Hydro evaluated three different alternative cases for FNGU (Case 1, Case 2 and Case 3). Combinations of a new gas turbine, duct firing, an upgrade or replacement of the existing OTSG and a new steam turbine generator were considered for FNGU. The cases are summarized in Table 2.

Table 2 FNGU Alternative Cases (Average Annual Conditions)

Case 1:

Gas Turbine	New GE LM 6000 DLE PD 44.1 MW
Generator	Existing 47 MW Alstom
OTSG	Upgrade existing OTSG with maximum additional tubes
Steam Turbine Generator	8.8 MW rating
Case 1 Capability[4]	51.6 MW

Case 2:

Gas Turbine[1]	New GE LM 6000 DLE PD 43.9 MW
Generator	Existing 47 MW Alstom
OTSG	New OTSG to deliver maximum steam production from waste heat of the gas turbine
Steam Turbine Generator	11.8 MW rating
Case 2 Capability[4]	54.5 MW

Case 2.1:

Gas Turbine[1]	New GE LM 6000 DLE PF 43.7 MW
Generator	Existing 47 MW Alstom
OTSG	New OTSG to deliver maximum steam production from waste heat of the gas turbine
Steam Turbine Generator	11.8 MW rating
Case 2.1 Capability[4]	54.5 MW

Case 3.1[2]:

Gas Turbine:	New GE LM 6000 DLE PF 43.7 MW
Generator	Existing 47 MW Alstom
Duct Firing[3]	Duct firing to a gas temperature of 538ºC with a new 2.1 meter duct extension using the same tube material as Case 2 and at the maximum design temperature of that tube material.
OTSG	New OTSG to deliver maximum steam production from waste heat of the gas turbine
Steam Turbine Generator	17.0 MW rating
Case 3.1 Capability[4]	59.2 MW

Case 3.2[2]:

Gas Turbine:	New GE LM 6000 DLE PF 43.7 MW
Generator	Existing 47 MW Alstom
Duct Firing[3]	Duct firing to a gas temperature of 727ºC with a new 5.8 meter duct extension using new tube material required for the higher temperature
OTSG	New OTSG to deliver maximum steam production from waste heat of the gas turbine
Steam Turbine Generator	28.5 MW rating
Case 3.2 Capability[4]	70.5 MW

Notes:

1. Case 2 and Case 2.1 were developed to evaluate air emissions using different available LM6000 DLE engines, PF and PD. A PF engine has lower NOx, but higher carbon monoxide (**CO**) emissions, as compared to a PD engine.
2. Case 3.1 and Case 3.2 will require the OTSG to be relocated to a new foundation since a new longer inlet duct is required for duct firing.
3. Duct firing using natural gas fuel increases the steam flow from the OTSG to the steam turbine generator and thereby increases the electricity output from the steam turbine generator. CCGTs equipped to duct fire can run with or without duct firing, depending on load and the economic value of the additional energy. When not duct firing, the performance is slightly reduced compared to a plant that is not equipped to duct fire.
4. The case capability is net of auxiliary power usage and as a result less than the sum of the gas turbine and steam turbine generator capacity.

Preliminary Screening of Alternative Design

From the evaluation of the cases, BC Hydro's preliminary conclusion is that Case 2 and Case 3.2 are appropriate to further investigate since:

- BC Hydro considers Case 1 to be too small to be of material benefit;
- Case 2 is the most efficient configuration as it is a full CCGT with no duct firing; when the CO emission criteria set out in the B.C. *Emissions Criteria for Gas Turbines*[1] is taken into consideration, the PD engine is a better choice over the PF engine, therefore Case 2 is better than Case 2.1; and
- Case 3.2 provides the greatest capability (70.5 MW) of all cases considered by making the most use of the duct firing capability, as a result it was selected over Case 3.1 for further investigation.

Comparison of Cases 2, Case 3.2 and FNG

Case 3.2 has the highest MW output. Case 2 and 3.2 are more efficient than FNG, and Case 2 is more efficient than Case 3.2 because it has no duct firing. Case 3.2 when not duct firing, provides slightly lower net capacity (53.8MW for Case 3.2 versus 54.5MW for Case 2 (Annual Average Conditions) at slightly lower efficiency (45.9 per cent for Case 3.2 versus 46.6 per cent for Case 2), as compared to Case 2. A comparison of Cases 2 and 3.2, and the FNG, at their rated operating level, is provided in Table 3 and Table 4.

Table 3 Summary of Evaluation

	Units	FNG	FNGU: Case 2	FNGU: Case 3.2
Cycle		SCGT	CCGT	CCGT
Engine (GE LM6000)		PC	PD	PF
OTSG		Existing	New module	New module
Duct firing		No	No	Yes
Annual Average Conditions				
Gross capacity	MW	47.0	55.7	72.1
Incremental gross capacity	MW	Not applicable	8.8	25.1
Net capacity	MW	45.9	54.5	70.5

[1] The 1992 *Emission Criteria for Gas Turbines* are used by the B.C. Ministry of Environment as a starting point when establishing air emission permit limits for new or modified natural gas-fired facilities.

	Units	FNG	FNGU: Case 2	FNGU: Case 3.2
Incremental Capacity	MW	Not applicable	8.6	24.6
Net cycle efficiency	Percentage	38.6	46.6	43.8
GHG intensity	t/GWh	481	398	431
Winter Peak Conditions				
Net Capacity	MW	47.8	57.3	75.5
Incremental Capacity	MW	Not applicable	9.5	27.2
Raw water usage	kg/h	31665	2001	2001
Effluent discharge	kg/h	14655	416	416

Table 4 Performance Estimates (Annual Average Conditions)

	Units	FNG	FNGU Case 2	FNGU Case 3.2
Gas temperature to OTSG	deg C	431	450	727
Gas Turbine Natural Gas Consumption	kg/h	7914	7506	7504
Duct Firing Natural Gas Consumption	kg/h	0	0	3176
Total Natural Gas Consumption	kg/h	7914	7506	10680
Gas Turbine Generator Capacity[1]	MW	47.0	43.9	43.7
Steam Turbine Generator Capacity	MW	0.00	11.9	28.4
Total Gross Capacity	MW	47.0	55.7	72.1
Auxiliaries	MW	1.1	1.3	1.7
Net Capacity	MW	45.9	54.5	70.5
Net heat rate	kJ/kWh	9319	7728	8212
Net efficiency	Percentage	38.6	46.6	43.8

Note:

1. All three gas turbines are different models of LM6000's (i.e. PC, PD, PF) and as a result have different capacities.

For average annual conditions, the estimated NOx emissions and stack flows for FNG and FNGU Case 2 and Case 3.2 are shown in Table 5.

Air emission permit (PA-15854) was issued on March 12, 1999 by the B.C. Ministry of Environment for the FNG. NOx and stack flow are all below the existing air emission permit levels. However, for Case 3.2, the CO emission would be 64 mg/SDm^3/s (at 15 per cent O_2 by volume) if operated without duct firing. A CO catalyst will be installed in the OTSG to reduce CO emissions by up to 80 per cent for Case 3.2.

Table 5 NOx AND CO Emissions and Stack Flows (Average Annual Conditions)

	Units	B.C. Emission Criteria for Gas Turbines	Air Emission Permit	FNG	FNGU: Case 2	FNGU: Case 3.2[3]
NOx	mg/SDm^3 at 15 per cent O_2 (Vol)	48	48	48	48	36
Stack Flow	SDm^3/s		107	98	97	91
CO	mg/SDm^3 at 15 per cent O_2 (Vol)	58[1]		33	29	50[2]

Note:

1. The emission criteria for CO is a guideline and is not regulated by the air permit.
2. A CO catalyst will be installed to reduce the CO emissions by up to 80 per cent from the number provided.
3. The emission data provided is at plant capacity i.e. duct firing operating.

The greenhouse gas (**GHG**) emissions for the annual average conditions and the net capacity for FNG, Case 2 and Case 3.2 are shown in Table 6. The GHG intensity for Case 2 and Case 3.2 will be lower than for the FNG. However, the total GHGs emitted in Case 3.2, when duct firing is used, will be higher than FNG because Case 3.2 uses more natural gas to produce the additional energy.

As shown in Table 3, water consumption and effluent discharge will both decrease significantly for Case 2 and Case 3.2 from their current levels for the FNG.

Table 6 Greenhouse Gases (GHG) Emissions

	Units	FNG (base)	FNGU Case 2	FNGU Case 3.2
GHG	t/GWh	481	398	431
GHG from base	Percentage change (t/GWh)		-17	-10
GHG	t/year	171200	168000	235800
GHG from base	Percentage change (t/year)		-2	+38

2.5.2 Environment and Social Impact Assessment

BC Hydro expects (on a per GWh basis) that FNGU, as compared to the FNG, will result in a reduction:

- in raw water and water treatment chemicals as a result of, among other things, the elimination of the direct steam injection for NOx control;
- in effluent generated as a result of a higher recovery rate of water since the FNGU is a closed loop configuration;
- of GHG emissions per MWh of electricity produced;
- of NOx emissions per MWh of electricity produced, and;
- of natural gas consumed per MWh of electricity produced.

Construction of the FNGU will be completed within the existing facility footprint. The construction impact on the surrounding environment and local community is expected to be minimal.

Environmental and social issues are identified through engagement and consultation with First Nations, government agencies and stakeholders. In particular, BC Hydro is in discussions regarding its plans for and the results of the assessment studies with federal and provincial government agencies, First Nations and stakeholders.

In July 2008, BC Hydro prepared draft work plans and terms of reference for the studies listed below and provided them to First Nations, government agencies and stakeholders for their review and comment:

- Stage 1 Preliminary Site Investigation;
- Vegetation, Wildlife and Surface Water Assessment;
- Socio-Economic Assessment; and
- Archaeology Overview Assessment.

The studies were initiated in August 2008 and are expected to be completed by October 2008. The draft assessment reports will be provided to First Nations, government agencies and stakeholders for their review and comment prior to finalizing.

A mitigation and compensation plan (if required) to address environmental impacts resulting from the FNGU and an Environmental Management Plan to address environmental impacts related to construction activities, will be developed in consultation with government agencies, First Nations and stakeholders. There is a Public Safety Management Plan (**PSMP**) in place for FNG. A specific PSMP will be prepared to address safety issues associated with the FNGU.

2.7 Other Applications and Approvals

BC Hydro does not expect FNGU to trigger a formal environmental assessment process under either the *Canadian Environmental Assessment Act* (***CEAA***) or the *B.C. Environmental Assessment Act* (***BCEAA***).

FNG only has one permit from the B.C. Ministry of Environment (air emission permit PA-15854). Effluent is handled through a Water and Effluent Treatment Services Agreement (dated March 15, 1999) with Spectra, which is referenced in the air emission permit. Fresh process water is also provided through an agreement with Spectra.

Pursuant to the B.C. *Public Notification Regulation*, if the emissions increase exceeds 10 per cent of the current authorized discharge level, the air emission permit will have to undergo a "significant amendment"[2] as opposed to a "minor amendment". Neither Case 2 nor Case 3.2 would result in a 10 per cent increase above current air emission permit parameters, and accordingly any required permit amendment would be a minor amendment.

Currently there is a six inch natural gas line located within the footprint of the FNG that will need to be relocated. Terasen Gas Inc. (**Terasen**) is responsible for moving the line prior to the upgrade and for ensuring that appropriate approvals/permits are acquired. BC Hydro will include the relocation of the natural gas line in its discussions with First Nations, government agencies and stakeholders to facilitate Terasen's permitting process.

Neither Case 2 nor Case 3.2 will cause significant adverse environmental or socio-economic effects, and BC Hydro anticipates that any environmental or socio-economic effects can generally be avoided or minimized through mitigation measures.

Pursuant to the *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008*, Policy Action No. 19 of the 2007 Energy Plan and the B.C. Government's Climate Action Plan, BC Hydro will be required to offset GHG emissions by 2016 for FNG or FNGU, and it will pay the carbon tax on natural gas usage from the present until 2016.

[2] A "significant" amendment has to go through the approval process at the B.C. Ministry of Environment office in Victoria while a "minor" amendment is something that would usually be approved at the local Ministry Office.

2.8 Public Engagement and First Nations Consultation

2.8.1 Introduction

Stakeholder engagement, and First Nations engagement and consultation, will be on-going throughout the Definition and Implementation phases of the FNGU.

The first phase of the engagement/consultation process began in spring 2008, in the context of the 2008 Fort Nelson Resource Plan (Appendix N1, Exhibit B-1-1). These activities included meetings on April 30 and May 1, 2008 with First Nations and community groups, and an Open House which was held on April 30, 2008. BC Hydro presented facts and an overview of FNG and the reasons for BC Hydro's proposal to upgrade the FNG, and the results expected from such an upgrade.

The second phase of the engagement/consultation process began in summer 2008 and is ongoing. On July 2 to 4, 2008 BC Hydro met with First Nations, government agencies and stakeholders. BC Hydro reiterated the reasons for FNGU, expanded on FNGU upgrade options under consideration, the BC Hydro environmental assessment studies referred to in section 2.5.2, and the estimated schedule for FNGU implementation.

Meetings with First Nations, government agencies and stakeholders are planned for fall 2008, to review the results of the BC Hydro assessment studies and the status of FNGU.

2.8.2 First Nations Engagement/Consultation

BC Hydro has initiated an engagement/consultation process with First Nations whose interests may be affected by FNGU. FNG lies within the Treaty 8 area. The two local Treaty 8 First Nations are the Fort Nelson and the Prophet River First Nations. FNG supplies both First Nations with electrical power. BC Hydro indicated to both First Nations its willingness to facilitate their participation in consultation activities, including review of documents. In addition to documentation already provided, BC Hydro will share draft BC Hydro environmental assessment study reports, information related to the selection of a configuration alternative, updates and supporting documentation related to regulatory approval processes.

Meetings were held with representatives of each the Prophet River First Nation and the Fort Nelson First Nation on May 1, 2008 and May 26, 2008, respectively to provide a preliminary opportunity to identify risks, concerns, and uncertainties regarding FNGU.

The second phase of the engagement/consultation process began in summer 2008 and is ongoing. The focus of this phase is on providing the two local area First Nations with more detailed information concerning FNGU, including opportunities to participate in BC Hydro's environmental assessment studies. This will enable the First Nations to determine whether the project might have impacts on their rights or interests. To this end, meetings were held with representatives of the Fort Nelson First Nation and the Prophet River First Nation on July 2 and July 3, 2008, respectively. In advance of these meetings, the First Nations were sent a written summary of project information. Both First Nations were also invited to participate in a site visit to FNG but declined. Information was presented on FNGU and the opportunities for First Nations involvement. The Treaty 8 Tribal Association has been notified of the consultation process and is being copied on all project correspondence to the Fort Nelson First Nation and the Prophet River First Nation.

Subsequent to the July 2 and 3, 2008 meetings, draft work plans and terms of reference for various BC Hydro environmental assessment studies were shared with the First Nations for their input, in particular the Archaeology Overview and Impact Assessment; Vegetation, Wildlife and Surface Water Surveys; Socio-Economic Impact Assessment; and Stage 1 Preliminary Site Investigation. With regard to the Archaeology Overview and Impact Assessment, the two First Nations were specifically solicited for their recommendation as to a preferred archaeological consultant. Additionally, employment opportunities, associated with the assessment studies, were made available to interested members of the Fort Nelson and Prophet River First Nations.

To date, First Nations: have raised no concerns or opposition to the FNGU; have demonstrated recognition of the supply issues facing the region; and have acknowledged that the project is in their interests as the FNG supplies their communities. The Fort Nelson First Nation indicated that they will be further considering potential project impacts and will advise of any additional feedback. To date, First Nations have not expressed a preference for one configuration alternative over another, but the Prophet River First Nation has indicated that their support of the FNGU includes support for all of the alternatives. The consultation process going forward will be the same regardless of the alternative selected.

2.8.3 Stakeholder Engagement

Subsequent to the engagement identified in the introduction above, BC Hydro held on July 2 to 4, 2008 additional meetings with key stakeholders including the Town of Fort Nelson Council and Administration; Fort Nelson and District Chamber of Commerce; Northern Rockies Regional District; Fire Chief and Bylaw Officer; Peace Liard Fort Nelson Health Unit; B.C. Ministry of Labour and Citizens' Services; RCMP; Fort Nelson General Hospital; B.C. Ministry of Forests; and B.C. Ministry of Environment. An Open House was also held on July 3, 2008. Print advertising for the July 3, 2008 Open House ran in the Northeast News and in the Fort Nelson News on July 2, 2008. Radio advertising for the July 3, 2008 open house ran on CKRX – Energy 102FM radio from June 26 to July 3, 2008.

Subsequent to the July 2 and 3, 2008 meetings, key stakeholders and government agencies were contacted and provided the opportunity to review and comment on the draft work plans and terms of reference for the various BC Hydro environmental assessment studies.

Similar to the issues raised during the Fort Nelson Resource Plan consultation, an interest was expressed to ensure infrastructure, including reliable electricity supply, is available in a timely manner to accommodate any significant load growth in the area due to activities in the oil and gas industry. Additionally, stakeholders raised concern regarding the in-service date (**ISD**) for the FNGU and for any potential expansion beyond the FNGU; wanting to ensure the ISDs do not slip.

The 2008 LTAP analysis demonstrates that new supply is urgently required to serve BC Hydro's customer demand in the Fort Nelson region under any scenario of future load growth analyzed. Stakeholders agree supply is urgently required and are expected to support both Case 2 and Case 3.2 because they are interested in expediting the FNGU to ensure the earliest ISD. However, it is believed based on early engagement with stakeholders that Case 3.2 would be preferred from a social and economic perspective, as it would provide a longer term solution, and is seen as a more significant and strategic investment in the Fort Nelson region.

2.10 Project Justification

2.10.1 Identification of Need

BC Hydro provided the load/resource balance based on current and committed capacity in section 1.5.6 of Appendix N1 to the 2008 LTAP (Exhibit B-1-1). Figures 1.6 and 1.7 of Appendix N1 are reproduced here as Figure 1, presenting the load/resource balance with all supply available (N-0),and Figure 2, with the largest single contingency assumed to be unavailable (N-1).

Figure 1 Fort Nelson Load/Resource Balance with N-0 Reliability

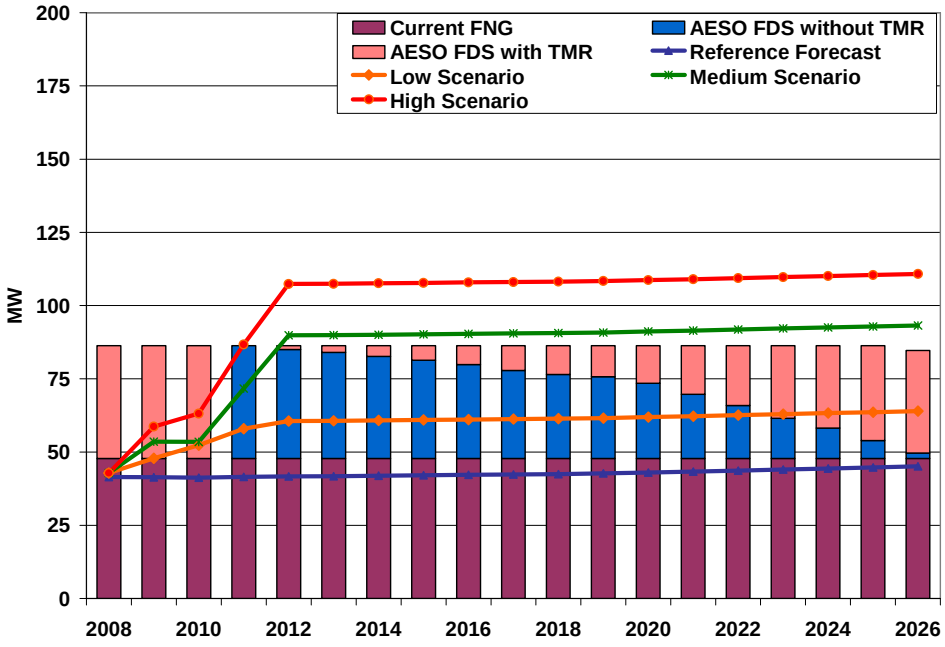
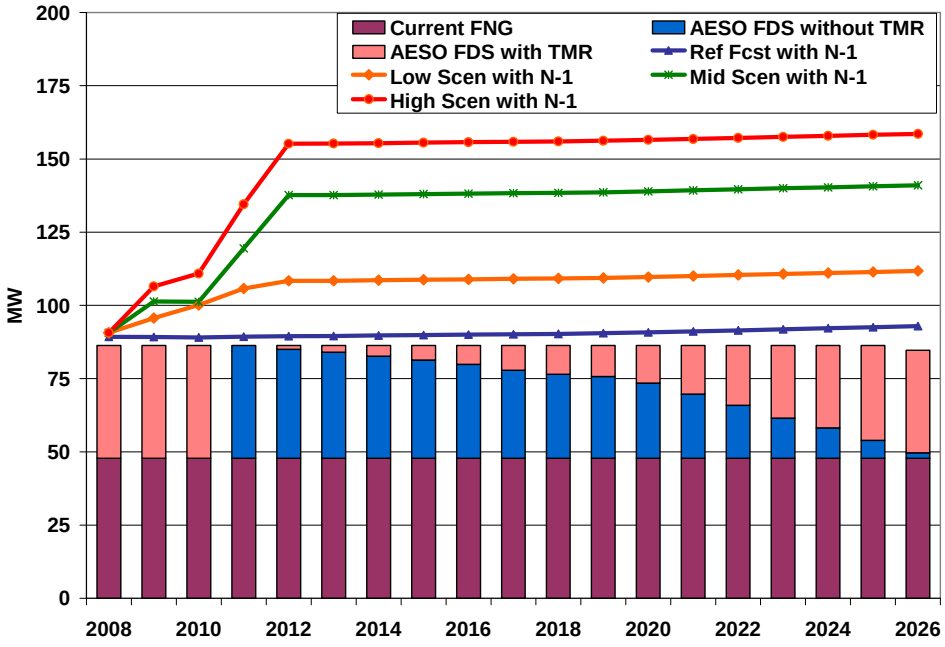


Figure 2 Fort Nelson Load/Resource Balance with N-1 Reliability



Subsequent to the development of the Reference Load Forecast and the three Scenarios, and since the open house BC Hydro held in Fort Nelson on April 30, 2008, which was approximately the last date for updating the analysis in the 2008 LTAP, BC Hydro has received several inquiries with respect to significant potential new load. As indicated in Figure 3, inquiries for 131 MW of new supply have been received.

Figure 3 New Load Inquiries (Cumulative Total MW)

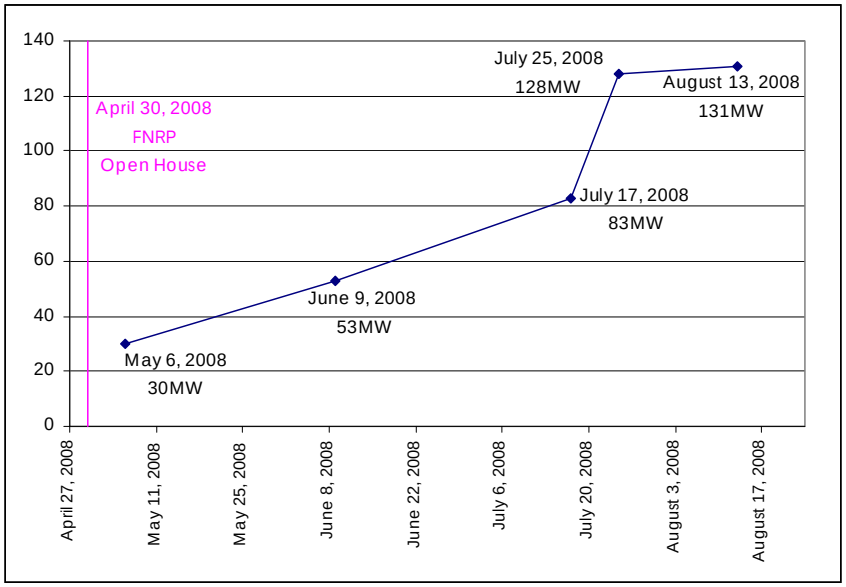


Table 7 presents the chronology of inquiries received between January 1, 2008 and August 12, 2008, and the date that the potential customer stated the load would materialize. Only one inquiry has triggered an interconnection study.

Table 7 Chronology of Inquiries for Service in Fort Nelson

Inquiry (Month)	Approximate In-Service-Date	Capacity Requested (MW)
May 2008	2010	10
	2013	10
	2016	10
June 2008	2009	8
	Unspecified	15
July 2008	Unspecified	30
	Unspecified	45
August 2008	2009	3
Total Load		**131**

Adding the inquiries in Table 7 that have approximate ISDs (i.e. 41 MW) to the Reference Forecast, without factoring in any probability of the new loads materializing, results in the load profile provided (New Inq. + Ref F/cast) in Figure 4 and Figure 5. Inquiries in Table 7 with unspecified ISDs are not included in these figures. The ISDs requested for the new load associated with projects mentioned above range from as early as summer 2009 through to 2017. If these projects, as requested, were to materialize, the total Fort Nelson load would be well above what was estimated in the Low Scenario in F2017 (see Table 8).

As a result of having load that must be served on an interruptible basis, the number of inquiries for new load received recently, requests for interconnection studies and public announcements on proposed oil and gas developments, BC Hydro believes the Low Scenario to be the prudent load growth profile on which to commit to provide incremental supply capacity and energy until there is increased certainty with respect to further load growth.

Figure 4 Fort Nelson Peak Demand Including Recent Inquiries (N-0)

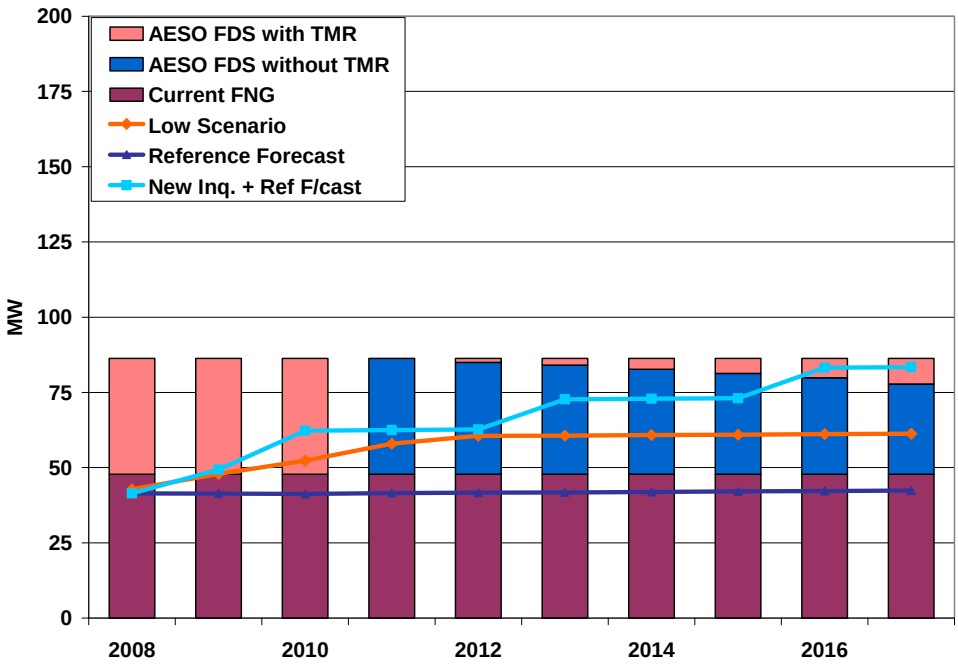
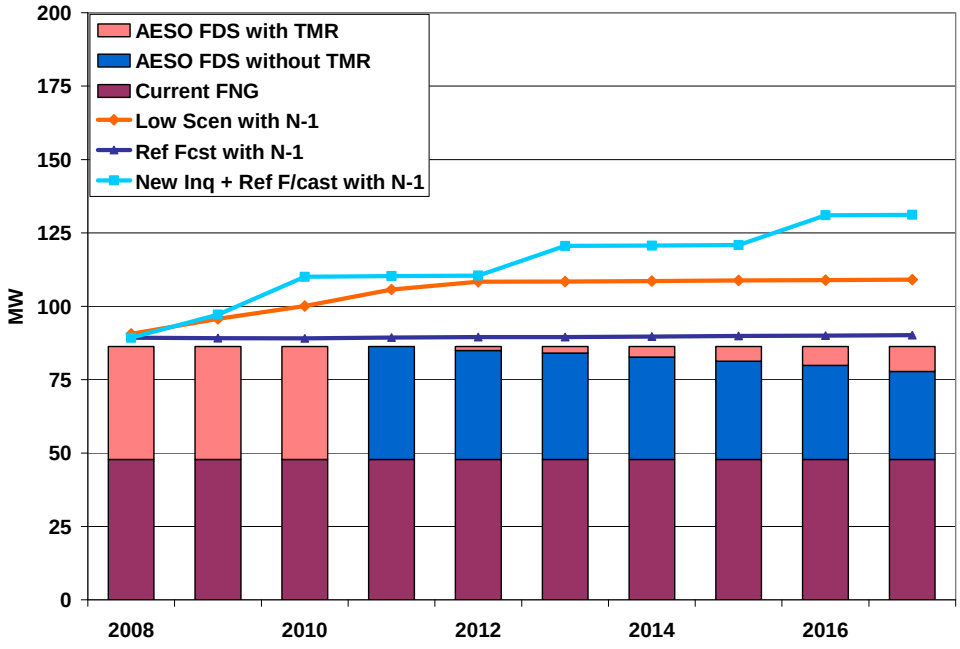


Figure 5 Fort Nelson Peak Demand Including Recent Inquiries (N-1)



The above figure shows that BC Hydro cannot meet the future load on a firm basis in any year without committing to new supply.

Table 8 Fort Nelson Regional Peak Demand – 2009-2017

	Load (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Reference Forecast	41.4	41.3	41.5	41.7	41.7	41.9	42.1	42.2	42.4
Low Scenario	47.9	52.3	57.9	60.6	60.6	60.8	61.0	61.1	61.3
New Inquires + Reference Forecast	49.4	62.3	62.5	62.7	72.7	72.9	73.1	83.2	83.4

2.10.2 Base Plan

In Appendix N1 of Exhibit B-1-1, BC Hydro identified the FNGU and the Alberta Electric System Operator (AESO) Option A1 as being the portfolio that:

- would provide the earliest incremental supply capacity and energy; and
- would provide approximately 60 MW, without transmission must run (**TMR**), because the matching of the size of the two individual sources would maximize the N-1 reliability.

The remainder of this section 2.10.2 provides an update with respect to the Base Plan including more precise load/resource balances in the short to mid-term. The capacity values presented are based on winter peak conditions.

2.10.2.1 ALBERTA TRANSMISSIONS OPTION TO INCREASE SERVICE FROM AESO

BC Hydro receives 38.5 MW of capacity (28.5 MW firm and 10 MW interruptible) from the AESO. Several generators must be dispatched on as TMR to provide even this level of supply to Fort Nelson.

The AESO's Northwest Alberta Area Upgrade[3] project has a final completion date of September 1, 2011 for all phases of the project. BC Hydro anticipates that, given the current BC Hydro contract capacity and the AESO's load forecast, with the completion of this project, the 10 MW of interruptible supply will become firm and the requirement for TMR will be removed.

[3] As described in section 1.5.5.4 and identified as A0 in the portfolio analysis of Appendix N1 of Exhibit B-1-1.

BC Hydro is of the view that it is likely that Option A1 provided by the AESO will be developed. If the AESO proceeds with this project, the increase in capacity could be available by the end of 2010.

This transmission expansion project is required if the AESO is to provide additional service to BC Hydro. Once upgraded, BC Hydro expects there to be approximately 63.9 MW in 2011 and 62.2 MW in 2012 available at the interconnection without requiring TMR. This level declines as load grows in the Rainbow Lake region of Alberta.

Commercial arrangements would have to be made to acquire any supply over the current contracted capacity of 38.5 MW.

2.10.2.2 FNGU CASE 2

In 2012, the FNGU Case 2 when combined with AESO Option A1 provides for:

- 57.3 MW on a firm basis;
- 4.9 MW (up to 62.2 MW) on an interruptible basis without TMR, that declines over time; and
- some possibility for additional interruptible service with use of TMR.

The load/resource balance calculation on which the above assessment is made is provided in Table 9.

Table 9 Load/Resource Balance with Case 2

	2009	2010	2011	2012	2013	2014	2015	2016	2017
FNGU CASE 2									
Total FNG/FNGU	47.8	47.8	47.8	57.3	57.3	57.3	57.3	57.3	57.3
AESO Capacity (no TMR)	0.0	0.0	63.9	62.2	61.2	59.9	58.5	57.1	55.0
Total Capacity (no TMR)	47.8	47.8	111.7	119.5	118.5	117.2	115.8	114.4	112.3
Largest contingency (with TMR required)[1]	47.8	47.8	63.9	62.2	61.2	59.9	58.5	57.3	57.3
Firm Capacity (N-1) no TMR	0.0	0.0	47.8	57.3	57.3	57.3	57.3	57.1	55.0
Low Scenario Load	47.9	52.3	57.9	60.6	60.6	60.8	61.0	61.1	61.3
Firm Surplus/Deficit no TMR	**-47.9**	**-52.3**	**-10.1**	**-3.3**	**-3.3**	**-3.5**	**-3.7**	**-4.0**	**-6.3**
AESO TMR Required	28.5	28.5	0.0	0.0	0.0	0.0	0.0	0.2	2.3
Firm Surplus/Deficit with TMR	**-19.4**	**-23.8**	**-10.1**	**-3.3**	**-3.3**	**-3.5**	**-3.7**	**-3.8**	**-4.0**
Interruptible Required	19.3	19.3	10.1	3.3	3.3	3.5	3.7	3.8	4.0
Firm + Interruptible Surplus/Deficit	**-0.1**	**-4.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note

1. The largest contingency post-2010 is the AESO interconnection. The largest contingency calculation is the AESO Capacity without TMR plus the TMR Required.

As indicated in Table 9, the combination of AESO Option A1 and FNGU Case 2 cannot meet the Firm Load, even with TMR. There remains three to four MW of load that would have to be served on an interruptible basis. While BC Hydro expects there to be up to approximately 35 MW of additional capability available from Alberta with TMR (as indicated in Appendix N1 of Exhibit B-1-1), the additional TMR capability is of no additional value for providing firm service as the interconnection is setting the N-1 condition (no room for firm capacity over the size of FNGU).

Figure 6 and Figure 7 provide the load/resource balance for N-0 and N-1 with Case 2.

Figure 6 **Fort Nelson Load/Resource Balance with FNGU Case 2 and AESO Option A1 (N-0)**

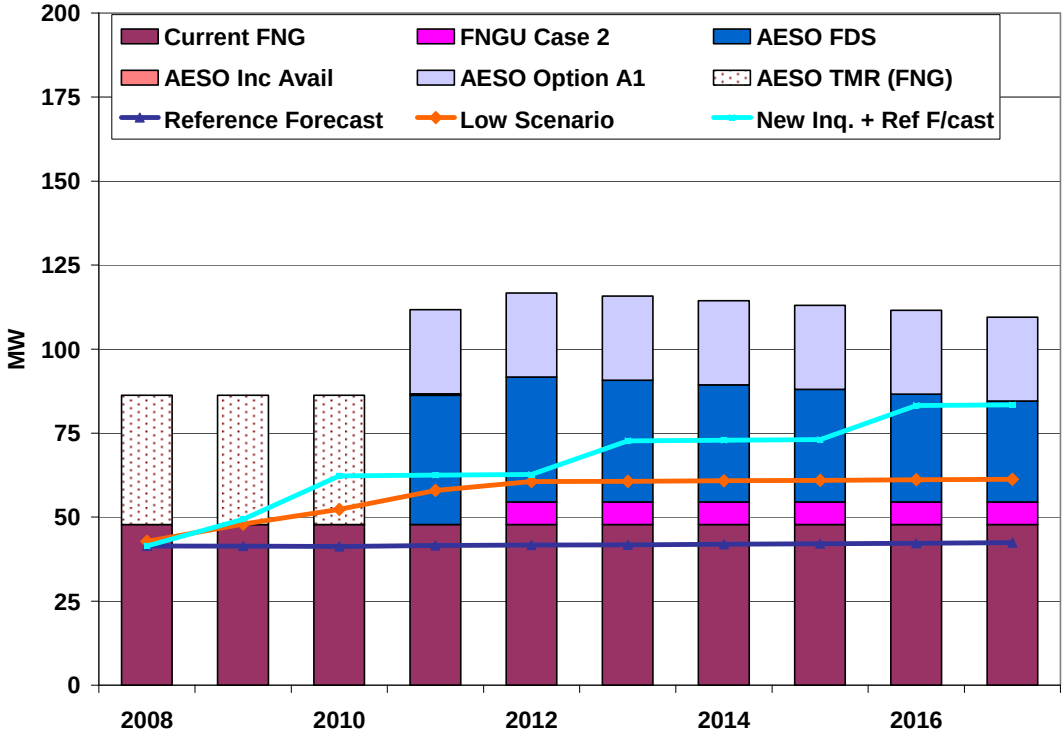
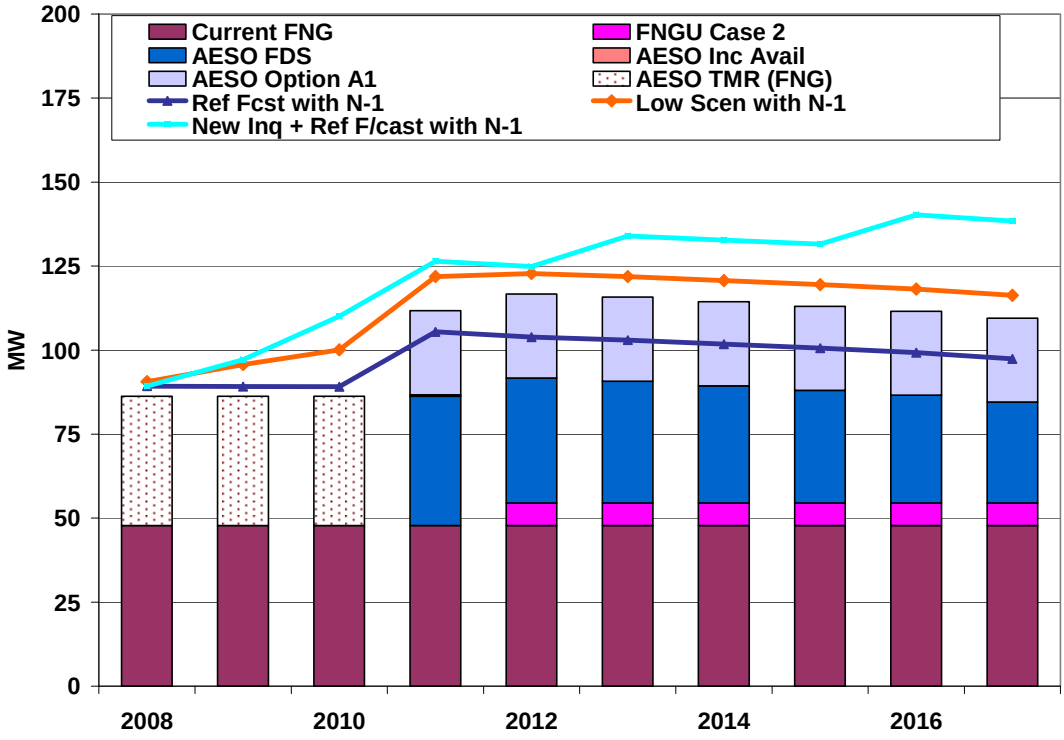


Figure 7 **Fort Nelson Load/Resource Balance with FNGU Case 2 and AESO Option A1 (N-1)**



2.10.2.3 FNGU CASE 3.2

The FNGU Case 3.2 better matches the expected capacity of approximately 63 MW that would be available from Alberta once Option A1 is in service. Together in 2012, the system would provide:

- firm service without TMR up to 62.2 MW, declining over time;
- an additional 13.3 MW (up to 75.5 MW) of firm service with use of TMR; and
- some additional capability to provide interruptible service, that is not required under the Low Scenario.

The load/resource balance calculation on which the above assessment is made is provided in Table 10.

Table 10 Load/Resource Balance for Case 3.2

	2009	2010	2011	2012	2013	2014	2015	2016	2017
FNGU CASE 3.2									
Total FNG/FNGU	47.8	47.8	47.8	75.5	75.5	75.5	75.5	75.5	75.5
AESO Capacity (no TMR)	0.0	0.0	63.9	62.2	61.2	59.9	58.5	57.1	55.0
Total Capacity (no TMR)	47.8	47.8	111.7	137.7	136.7	135.4	134.0	132.6	130.5
Largest contingency	47.8	47.8	63.9	75.5	75.5	75.5	75.5	75.5	75.5
Firm Capacity (N-1) no TMR	0.0	0.0	47.8	62.2	61.2	59.9	58.5	57.1	55.0
Low Scenario Load	47.9	52.3	57.9	60.6	60.6	60.8	61.0	61.1	61.3
Firm Surplus/Deficit no TMR	**-47.9**	**-52.3**	**-10.1**	**1.6**	**0.6**	**-0.9**	**-2.5**	**-4.0**	**-6.3**
AESO TMR Required	28.5	28.5	0.0	0.0	0.0	0.9	2.5	4.0	6.3
Firm Surplus/Deficit with TMR	**-19.4**	**-23.8**	**-10.1**	**1.6**	**0.6**	**0.0**	**0.0**	**0.0**	**0.0**
Interruptible Required	19.3	19.3	10.1	0.0	0.0	0.0	0.0	0.0	0.0
Firm + Interruptible Surplus/Deficit	**-0.1**	**-4.5**	**0.0**	**1.6**	**0.6**	**0.0**	**0.0**	**0.0**	**0.0**

The use of FNGU Case 3.2 with duct firing in conjunction with AESO Option A1 including TMR best matches the Low Scenario. All load in the Low Scenario can be met on a firm basis with a small amount of TMR requirement. The capability of the FNGU with duct firing is better matched with the capability of AESO Option A1 with some TMR usage. Assuming that there is up to 35 MW of TMR capability available (described in FNGU Case 2 above), there would be room in this case to provide up to 75.5 MW (size of FNGU) on a firm basis with TMR support.

The load/resource balance calculation on which the above assessment is made is provided in Figure 8 and Figure 9 provide the load/resource balance for N-0 and N-1 with Case 3.2.

Figure 8 Fort Nelson Load/Resource Balance with FNGU Case 3.2 and AESO Option A1 (N-0)

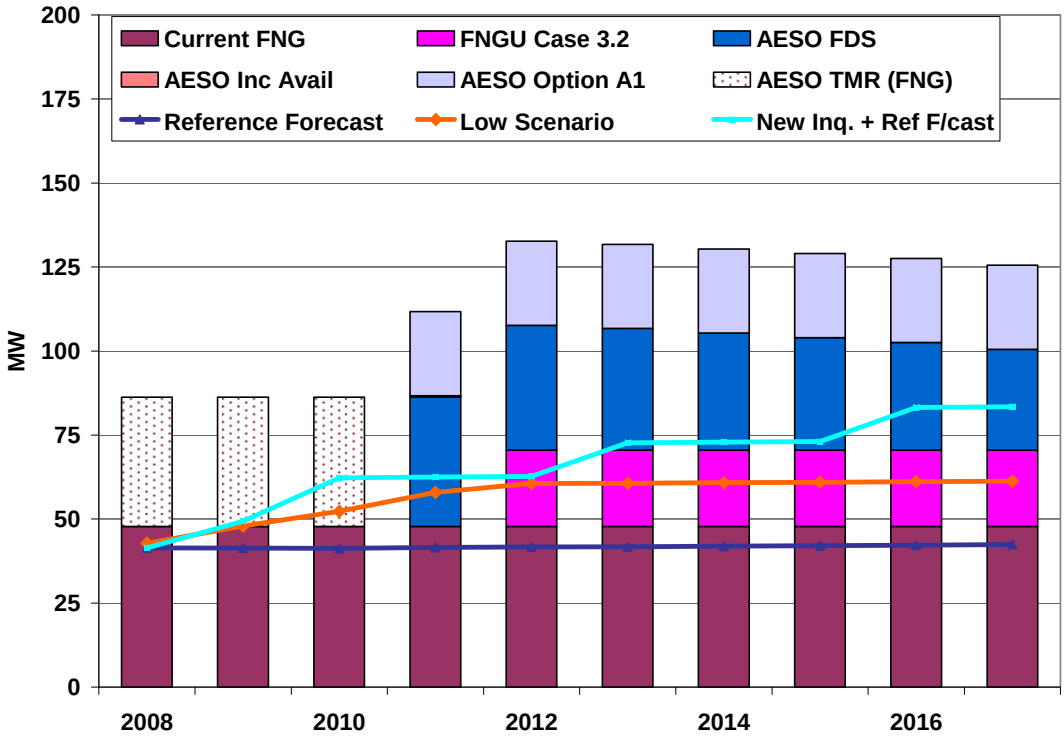
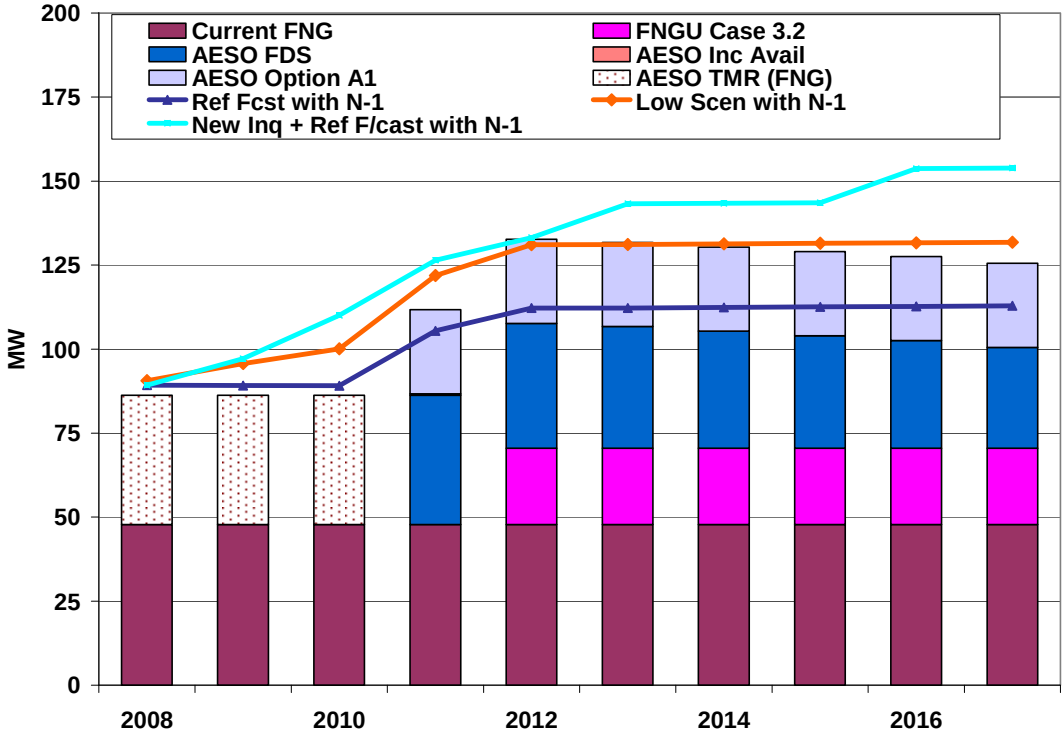


Figure 9 Fort Nelson Load/Resource Balance with FNGU Case 3.2 and AESO Option A1 (N-1)



2.10.3 Alternatives to FNGU

In Appendix N1, Exhibit B-1-1, BC Hydro identified four alternatives to the FNGU. They are:

- a new CCGT generator in the Fort Nelson area;
- clean or renewable projects;
- increased supply from Alberta (in addition to AESO Option A1); and
- interconnection of Fort Nelson to the BC Hydro integrated system.

BC Hydro is of the view that none of these alternatives are replacements for the FNGU.

2.10.3.1 New CCGT

A second CCGT would add approximately 55 to 70 MW of capacity. This option provides approximately 20 to 35 MW more capacity than required to meet the Low Scenario. In addition, a new CCGT is not an alternative to FNGU because a new CCGT would not be able to meet an ISD of 2012, which is required to meet the Low Scenario. The earliest ISD for installing a second CCGT in the Fort Nelson area depends on whether:

- the second CCGT is a Resource Smart project sited at BC Hydro's FNG site (named the Fort Nelson Expansion Project); or
- the second CCGT is a new, greenfield development.

BC Hydro has, for purposes of estimating the ISD for the two CCGT scenarios, assumed a two to three year period for the engineering, procurement and construction.

(a) Fort Nelson Expansion Project

The earliest ISD for the Fort Nelson Expansion Project is likely late 2013, for the following reasons:

- Unlike FNGU, the Fort Nelson Expansion Project would trigger BCEAA because pursuant to the Reviewable Projects Regulation it would be a modification to an existing facility resulting in FNG having a rated nameplate capacity that has increased by 50 MW or greater. Pursuant to section 8 of BCEAA, no construction could begin on the Fort Nelson Expansion Project until an Environmental Assessment Certificate (**EAC**) had been obtained. BC Hydro estimates that the BCEAA process would take approximately 14 months from submission of the project description to the B.C. Environmental Assessment Office to issuance of the EAC. In estimating the length of time of the BCEAA process, BC Hydro has taken into account the fact that some of the existing infrastructure could be used; BC Hydro estimates a longer BCEAA process for a greenfield CCGT. BC Hydro has also concluded that CEAA is likely not triggered for the Fort Nelson Expansion Project; this assumption likely does not hold for a greenfield CCGT. See below.
- Similar to the FNGU, a determination for Fort Nelson Expansion Project expenditures would be sought from the British Columbia Utilities Commission (BCUC) pursuant to section 44.2 of the Utilities Commission Act (UCA). This process could be a hearing

lasting approximately 7 months. This process could occur while the BCEAA process is occurring as long as BC Hydro had a good estimate of the likely environmental mitigation costs. BC Hydro has assumed this to be the case with respect to the Fort Nelson Expansion Project.

(b) A New Greenfield CCGT

The earliest ISD for a new greenfield CCGT is likely to be mid to late 2014, for the following reasons:

- Pursuant to Policy Action No. 13 of the 2002 Energy Plan, this project would not be a Resource Smart project and therefore must be an independent power producer (**IPP**) project. A copy of Policy Action No. 13 is Attachment A to this evidentiary update. Accordingly, a power acquisition process – whether a Call for Tenders or a Request for Proposals – would be required. The power acquisition process would likely take approximately 18 months from development through to filing any Electricity Purchase Agreement (**EPA**) awarded to an IPP with the BCUC pursuant to section 71 of the UCA. Difficult issues of dispatchability and which party – the IPP or BC Hydro - should bear the natural gas price and GHG risks would need to addressed both in the EPA and in the section 71 filing.

- The ISD assumes that BC Hydro would not seek a determination pursuant to section 44.2 of the UCA for expenditures related to the new greenfield CCGT, prior to the power acquisition process and the section 71 filing. Ministerial Order M202 exempts IPPs selling electricity to BC Hydro from the requirement to obtain a Certificate of Public Convenience and Necessity. However, BC Hydro may wish to reduce regulatory risk and seek a BCUC determination.

- Again, unlike the FNGU, a new greenfield CCGT would trigger BCEAA because, under the Reviewable Projects Regulation, it would be a new facility with a rated nameplate capacity of equal to or greater than 50 MW. In BC Hydro's view, the environmental assessment process for a new greenfield CCGT would be approximately 18 months, longer than for the second CCGT at the FNG site because: (1) there may be location impact issues; and (2) CEAA may be triggered. Generally speaking, BC Hydro's experience has been that IPPs are reluctant to advance too far into the BCEAA process without an EPA, and that accordingly the BCEAA process would likely occur after the section 71 process.

2.10.3.2 REQUESTS FOR EXPRESSIONS OF INTEREST FOR CLEAN RESOURCES

BC Hydro's 2007 Requests for Expressions of Interest for Clean Resources (**RFEOI**) received a total of sixteen responses (one response was disregarded as ineligible because it was not clean or green). The submissions, broken down by project type, were: six bioenergy, two small hydro, six wind, one geothermal and one pumped storage.

Since this was an RFEOI, the submissions were not proposals and thus did not provide a commitment from the proponents. As a result, these potential projects could only provide BC Hydro with an indication of whether it is possible to conduct a successful clean or green electricity call in the Fort Nelson region.

In the Fort Nelson region, BC Hydro requires a reliable source of dependable capacity that is dispatchable and economically capable to produce energy at relatively high capacity factor. This reliability is critical at all times, including during light load hours when the region's gas-turbine generators may be dispatched down to minimum MW levels, or even dispatched off.

Of the sixteen responses, only the bioenergy projects could potentially provide this level of reliability in supply. However, these projects are typically small, have significant fuel supply risk, and may not be dispatchable.

It is unlikely that BC Hydro's supply need could be met by clean or renewable resources alone, given the timing and the amount of the potential load growth in the area.

2.10.3.3 BCTC TRANSMISSION INTERCONNECTING FORT NELSON TO INTEGRATED SYSTEM

BC Hydro has initiated a planning level assessment with British Columbia Transmission Corporation (**BCTC**) for the interconnection of Fort Nelson to the BC Hydro integrated system.

The estimated ISD of 2015 was based on BCTC's Northwest Transmission Line (**NTL**) project which involves a line of similar length and voltage. The reliability of the new transmission line is assumed to be similar to the existing 144 kV line between Fort Nelson and Alberta.

Unlike the NTL project, the extension of the BCTC interconnected system to Fort Nelson would create another tie line between B.C. and Alberta. This change in operation would affect commercial and regulatory arrangements that currently exist between BC Hydro and the AESO.

The timing of this line cannot meet the load growth for the Low Scenario. This transmission alternative is something that could meet substantially more load than the Low Scenario and would include a significant risk of stranded investment if proceeded with and loads above the Low Scenario did not materialize.

2.10.3.4 ALBERTA TRANSMISSIONS OPTION A2

The AESO also presented BC Hydro with Option A2 which could, in combination with A1, supply 30 MW in addition to the 25 MW of Option A1.

Option A2 involves the construction of a new transmission line and two large reactive devices. The cost of Option A2 is almost four times the cost of Option A1. The estimated ISD of 2012 is considered optimistic, given the infrastructure needed for this option. Further, Option A2 entails an increased level of both GHG risk and regulatory risk:

- GHG Risk - As described in section 4.2.2.2 of the 2008 LTAP (Exhibit B-1), the B.C. Government may deem GHG emissions outside B.C. to be attributable to a regulated operation and "in relation to electricity [deem GHG] emissions associated with generation and transmission of the electricity until the point at which the electricity is received by the British Columbia electricity grid to be attributable" to a regulated operation under section 39(c) of the Greenhouse Gas Reduction (Cap and Trade) Act. In addition, the Western Climate Initiative (WCI) released their "Draft Design of the Regional Cap-and-Trade Program" (WCI Program) on July 23, 2008.[4] The Province of B.C. is a Partner to the WCI, and has committed to participating in the regional GHG cap-and-trade program. Section 2.2 of the WCI Program provides that B.C. is responsible for GHG emissions associated with electricity generated outside the WCI and delivered to B.C. as the first WCI jurisdiction. Alberta is not part of the WCI.

- Regulatory Risk – In Alberta, both transmission service and electricity market services are provided by the AESO. Effective January 1, 2008, the AESO is regulated by the Alberta Utilities Commission; a regulatory entity that was created by

[4] See Attachment 1 to the response to BCUC IR 1.67.1, Exhibit B-3.

the passage of Bill 46, the Alberta Utilities Commissions Act (**AUC Act**).The Bill also includes other amendments to the Electric Utilities Act (**EUA**) of 2003. One amendment resulting from the AUC Act is an amendment that modifies the AESO's obligations with respect to planning the transmission system. Prior to the passage of the AUC Act, the AESO was to plan the transmission system based on the needs of the market participants (of which BC Hydro was one). The AUC Act modified the AESO's obligation under the EUA to plan the system capability based on provincial needs.

A commitment to rely on capacity above that provided by AESO Option A1 would result in a need for importing firm energy, in addition to providing reserve, to meet the load. This heightens the possible impact of both of the above risks.

2.10.3.5 SUMMARY OF ALTERNATIVES TO THE FNGU

BC Hydro has determined that sufficient resources are required to meet, at a minimum, the load identified by the Low Scenario. This results in an approximate requirement for 63 MW by 2012.

The only portfolio of resources that BC Hydro is aware of that can provide this requirement on a firm basis is the combination of the AESO Option A1 transmission upgrade and the FNGU Case 3.2.

The AESO Option A1 along with the FNGU Case 2 can provide the supply, but the load above 57.3 MW would likely need to be supplied on an interruptible basis.

None of the other options are available in time.

FNGU Case 3.2 has the following advantages over the other alternatives:

- FNGU provides firm energy and capacity to the Fort Nelson area, when matched with the AESO Option A1;
- FNGU has the earliest ISD of the alternatives considered;
- FNGU is contained within the existing footprint of the FNG and as a result does not trigger a BCEAA or CEAA review;

- First Nations and stakeholder engagement for FNGU is advanced and First Nations and stakeholders support FNGU; and

- FNGU will result in a more efficient gas plant in Fort Nelson, leading to lower raw water usage, effluent discharge from the facility and lower GHGs and NOx emissions.

FNGU Case 3.2 is the most appropriate project to be advanced to serve the growing load in the Fort Nelson area, since it has a number of advantages over other potential sources of energy and capacity. FNGU provides significant benefits to the Fort Nelson system, by adding firm energy and capacity to meet load growth in the area.

2.10.4 Implications of the Evidentiary Update

The Low, Medium and High Scenarios have been created to assist BC Hydro planning by reducing the lead time to respond, in case new loads do commit. The scenarios in this case have been developed based on expectations of load without commitments. While BC Hydro tries to anticipate and provide for new load growth generally, BC Hydro would be imprudent to construct any large new supply, where such supply could cause material stranded assets, in the absence of firm commitments from customers that the new large loads will materialize.

The load growth scenarios remain relevant for planning purposes since they, when combined with the portfolio analysis, provide sufficient justification for initiating work to identify and advance cost-effective additional resource options best able to meet those load requirements, should they materialize, but without prematurely committing BC Hydro to significant capital investments.

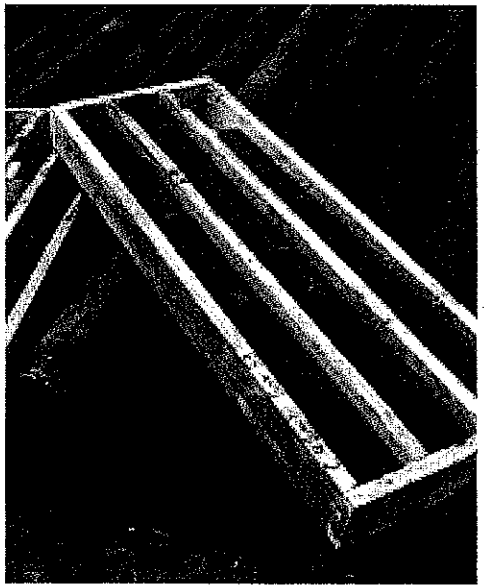
The amount of interest expressed in new development in the greater Fort Nelson region, including the Horn River region, increases the importance of further advancing work on the supply options (as identified in section 1.8 of Appendix N1 Exhibit B-1-1) that would be available in addition to the AESO Option A1 and the FNGU Case 3.2 to meet the incremental load growth that may occur above the Low Scenario.

Attachment

A

Energy for our Future: A Plan for B.C.

Policy Action #13



of utility rates of return, and the adoption of performance-based regulation and alternative dispute resolution. To fulfill its mandate, the Commission will be strengthened by appointing two full-time Commissioners. The Utilities Commission Act will be amended to focus more on performance-based and results-based regulation, including negotiated settlements, and to define effective consumer participation.

MORE PRIVATE SECTOR OPPORTUNITIES

To increase the role of the private sector in energy supply, private power production will be encouraged, access to the transmission system will be improved, oil and gas investment will be supported, and some customers will be able to choose their suppliers.

INVESTMENT IN PRIVATE POWER

Policy Action #13 (new): The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.

The private sector is well positioned for power development, given its ability to find entrepreneurial capital, efficiently build and operate facilities, and take on the associated risk. B.C.'s independent power producers (IPPs) have already demonstrated that they can come forward with cost-effective projects. With BC Hydro's participation limited to efficiency improvements and capacity upgrades at existing facilities, IPPs will be able to serve new domestic needs and explore opportunities in the export market. The intent will be to encourage the private sector to find a variety of innovative and economical ways to satisfy the growing demand for power.

BC Hydro's relative strengths lie in the operation of large-scale hydroelectric generation. While BC Hydro does not plan to invest in the construction of new hydroelectric facilities at the present time, any proposed new BC Hydro hydroelectric facility, such as Peace Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply. Cabinet will then decide whether the project should be developed by BC Hydro or the private sector.

Policy Action #14 (new): Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

New stepped pricing (see Conservation and Efficiency) will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the utility's cost of new supply. These larger customers will be able to meet all or a portion of their consumption from private generation. This policy change introduces retail competition for large BC Hydro customers. Aquila Networks Canada already offers retail access to its industrial customers.

Policy Action #15 (new): The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.

A new publicly owned entity, BC Hydro Transmission Corporation, will be responsible for planning, operating, and managing BC Hydro's transmission system. The transmission assets will continue to be owned by BC Hydro. The corporation will have a separate board of directors and will be regulated by

Actions under other strategic objectives that also support secure, reliable supply:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.