Q. Provide a timeline, supported by documentation, showing the decisions that were taken regarding the timing of the purchase of the new combustion turbine at the Holyrood Thermal Generating Station.

A. For Hydro's Island Interconnected System, a capacity deficit is defined by the Loss of Load Hours (LOLH) exceeding 2.8 hours. This is a probabilistic measure that considers among other things, the forecast load, generation maintenance requirements, the generation available and a probability of generation forced outages[1]. Hydro uses a computer model called Strategist to determine LOLH. Using Strategist with other economic inputs, a least cost generation expansion plan can be determined.

A generation expansion plan that included the purchase of a new combustion turbine (in-service in 2012) as an option was first identified in 2008 in the *Generation Planning Issues 2008 Mid Year Update – July 2008* in Table 7-1, page 21 (see PUB-NLH-002 Attachment 1). In 2010 in the *Generation Planning Issues 2010 July Update* in Table 7-1, page 22 (see PUB-NLH-002 Attachment 2), a combustion turbine was identified to mitigate a capacity deficit projected to occur in 2014. This deficit has moved out further into the future with subsequent Strategist analyses. The most recent analysis in 2012 shows the capacity deficit occurring in 2015. The least cost generation plan to correct this deficit (see Table 7-1, found on page 24 of the *Generation Planning Issues November 2012*, contained in PUB-NLH-001 Attachment 1), indicated that a combustion turbine should be purchased and constructed to be in service in 2015.

[1] Forced outage probability is established by generation type and forced outage rates that are benchmarked against actual unit performance.

In 2011, Hydro commenced the preliminary site analysis, budget and engineering work for construction of the combustion turbine. In 2012, based upon a risk assessment, Hydro determined that the combustion turbine would be best established at Holyrood. Hydro was finalizing an application for the Board in late 2013 and evaluating other alternatives to ensure the proposed solution was the lowest cost for customers. In addition, with the decision to re-establish the blackstart generation capacity at Holyrood using the eight diesel units, Hydro is assessing the appropriateness of previous conclusions. Hydro intends to submit its application by the end of March 2014 for a proposed solution to meet the projected capacity deficit.

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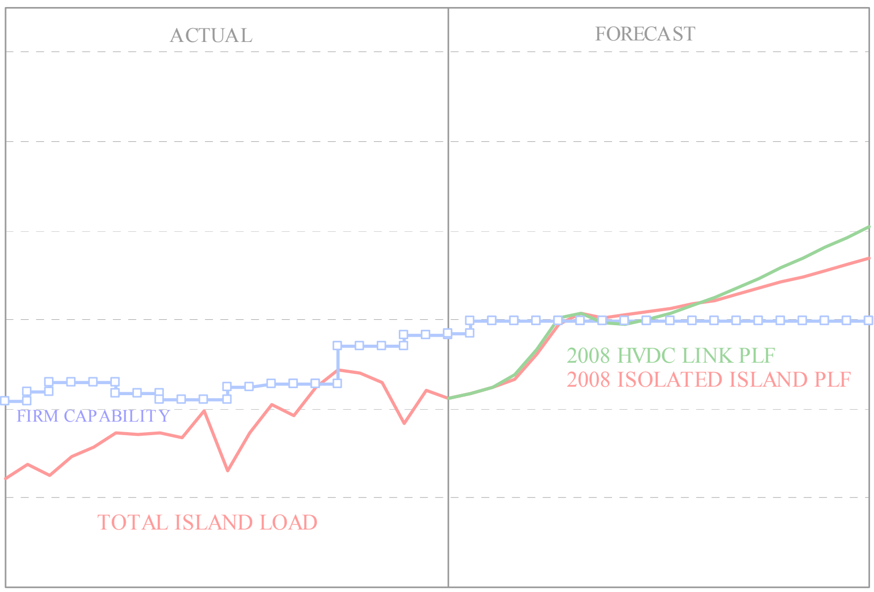
Generation Planning Issues

2008 Mid Year Update



System Planning

July 2008

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Executive Summary

This report provides an overview of the Island Interconnected System (the System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

Under the Province's Energy Plan Hydro is to evaluate a High-Voltage Direct Current (HVDC) Link to deal with emissions from its Holyrood Thermal Generating Station (HTGS). This requires Hydro to maintain two planning load forecasts and two preliminary generation expansion plans; one for the HVDC Link and one for the Isolated Island scenario. Based on an examination of the System's existing plus committed capability, in light of the 2008 Planning Load Forecasts (PLF) and the generation planning criteria, the System can expect capacity deficits starting in 2013 under both scenarios and firm energy capability deficits starting in 2013 for the HVDC scenario and 2014 for the Isolated Island scenario.

Due to the economic and environmental benefits associated with displacing heavy fuel-oil at the HTGS, Hydro signed agreements for the development of wind generation projects at St. Lawrence and Fermeuse, both with planned in-service dates in 2008. A decision for a third wind project would be required by at least 2009 in order meet a 2010 in-service date.

Beyond the wind projects, a decision on what alternative to pursue is required by 2009 in order to be in-service by 2012 to meet capacity and firm capability requirements that begin in 2013. In order to meet these requirements, Hydro has identified two generation alternatives: a 50 MW combustion turbine in the event the HVDC Link scenario is ultimately pursued; and the 23 MW Portland Creek hydroelectric plant in the event the traditional Isolated Island scenario is pursued.

It should be noted, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVDC Link – Hydro must be prepared to react if the proposed Lower Churchill Project is delayed or fails to receive sanction;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both an Isolated Island and HVDC Link future;
- Emissions control considerations – Hydro must remain vigilant in considering the impact that environmental initiatives could have on production costing and future planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling due to increased environmental scrutiny in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept and costs.

Table of Contents

1.0 Introduction

This report provides an overview of the Island Interconnected System (the System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

This report is normally completed at year end, but given the many uncertainties at the end of 2007, with respect to the load forecast and generation expansion alternatives, it was decided to defer the report until some of the uncertainties were clarified. This report is a mid year review and while some of the uncertainties have been resolved, others still exist. This report should be considered as an interim report until a further update can be completed at the end of 2008.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). Option A was to replace HTGS produced electricity with electricity from the lower Churchill River development via a High-Voltage Direct Current (HVDC) transmission link to the Island. Option B was to install scrubbers and electrostatic precipitators to control emissions at the HTGS and maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on HTGS produced electricity. These two options require significantly different strategies to effectively implement and require the development of two separate, preliminary, generation expansion plans to manage the near-term until a decision can be made on which option Hydro will pursue for future development.

This report addresses the timing of the next requirement, in light of the most recent load forecast, for additional generation supply under both options and the resources available to meet that requirement. The report also identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

2.0 Load Forecast

This review utilizes the 2008 long-term Planning Load Forecast (PLF) as prepared in the spring of 2008. Long-term load forecasts for the Province are derived using Hydro's own electricity models and are driven by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. For this analysis, Hydro has included the lower Churchill River generation and transmission investments as an alternative to the isolated Island future while recognizing that these developments have yet to be technically committed through project sanction. Some key assumptions respecting incremental economic activity for both generation supply futures are:

- Continued newsprint operations at Corner Brook[1] and Grand Falls;
- Single Island oil refining operation at Come by Chance;
- Start-up of the Vale Inco NL[2] nickel processing facility on the Island in 2012;
- Teck Cominco[3] mining operations continuing through 2014.

In terms of high-level economic indicators, growth rate summaries for the HVDC Link and Isolated Island scenarios are presented in Table 2-1. As indicated in the table, there are modest longer-term economic differences associated with the two generation supply alternatives.

[1] Kruger Inc. announced on October 22, 2007, that it was shutting down Paper Machine No. 1, for an indefinite period of time, as of November 5, 2007.
[2] Voisey's Bay Nickel Company changed its name to Vale Inco Newfoundland and Labrador Limited (Vale Inco NL) on November 29, 2007.
[3] Teck Cominco completed the acquisition of Aur Resources on September 27, 2007

Table 2-1

Provincial Economic Indicators – 2008 PLF				
		2007-2012	2007-2017	2007-2027
Adjusted Real GDP at Market Prices* (% Per Year)	HVDC Link	1.9%	0.9%	0.9%
	Isolated Island	1.0%	0.8%	0.9%
Real Disposable Income (% Per Year)	HVDC Link	2.3%	1.5%	1.4%
	Isolated Island	1.6%	1.4%	1.3%
Average Housing Starts (Number Per Year)	HVDC Link	2,352	2,229	2,000
	Isolated Island	2,339	2,211	1,988
End of Period Population ('000s)	HVDC Link	504	497	489
	Isolated Island	501	492	487
*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.				

Hydro carries out system planning for the total System and that includes the demand and energy supplied by Hydro's customer-owned-generation resources in addition to Hydro's bulk and retail electricity supply. The projected electricity growth rates for the System under both the HVDC Link and Isolated Island cases are presented in Table 2-2. An important source of load growth for the utility sector on the Island continues to be a high penetration for electric space and water heating systems across residential and commercial new construction. For Hydro's industrial customers, current operations are assumed for the newsprint mills and oil refinery, the Teck Cominco mine is expected to operate through 2014 and the Vale Inco NL nickel processing facility will be commissioned in 2012.

Table 2-2

Electricity Load Growth Summary – 2008 PLF				
		2007-2012	**2007-2017**	**2007-2027**
Utility[1]	HVDC Link	1.6%	0.8%	1.2%
	Isolated	1.4%	0.9%	0.9%
Industrial[2]	HVDC Link	0.1%	1.5%	0.9%
	Isolated	0.1%	1.5%	0.9%
Total	HVDC Link	1.2%	1.0%	1.0%
	Isolated	1.0%	1.1%	0.9%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, AbitibiBowater[4], North Atlantic Refining, Teck Cominco and Vale Inco NL.

Table 2-3 provides a summary of the 2008 PLF projections for electric power and energy for the System for the period 2008 to 2017. Similar long-term projections are also prepared for the Labrador Interconnected System and for Hydro's Isolated Diesel Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term PLF that was used to complete the generation expansion analysis.

[4] On January 29, 2007, Abitibi-Consolidated Inc. (ACI) and Bowater Inc. announced their intentions to merge. The merger was formally completed on October 29, 2007 with the creation of AbitibiBowater Inc.

Table 2-3

Electricity Load Summary – 2008 PLF						
HVDC Link	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]
2008	1,302	5,888	283	2,030	1,566	8,112
2009	1,323	5,965	278	2,007	1,582	8,167
2010	1,341	6,039	278	2,016	1,600	8,251
2011	1,355	6,145	318	2,039	1,622	8,380
2012	1,372	6,212	356	2,262	1,652	8,673
2013	1,388	6,237	364	2,576	1,721	9,017
2014	1,393	6,231	357	2,644	1,725	9,079
2015	1,404	6,167	357	2,599	1,730	8,970
2016	1,398	6,143	357	2,599	1,724	8,945
2017	1,397	6,206	357	2,599	1,724	9,009
Isolated Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]
2008	1,302	5,888	283	2,030	1,566	8,112
2009	1,324	5,965	278	2,007	1,582	8,167
2010	1,341	6,039	278	2,016	1,600	8,251
2011	1,353	6,097	318	2,039	1,621	8,332
2012	1,368	6,145	356	2,262	1,649	8,606
2013	1,381	6,176	364	2,576	1,714	8,955
2014	1,387	6,222	364	2,644	1,720	9,071
2015	1,400	6,219	357	2,599	1,726	9,022
2016	1,404	6,260	357	2,599	1,730	9,064
2017	1,412	6,293	357	2,599	1,738	9,097

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses and demands are coincident peak demands.

3.0 System Capability

Hydro is the prime supplier of system capability to the Island Interconnected System, accounting for 80 percent of its net capacity and 79 percent of its firm energy. Capability is also supplied by customer generation from Newfoundland Power Inc., Corner Brook Pulp and Paper Limited (Kruger Inc.) and AbitibiBowater Inc. Hydro also has contracts with four Non-Utility Generators (NUGs) for the supply of power and energy and has signed two contracts for wind power that will become operational later in 2008.

Hydroelectric generation accounts for 65 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from thermal resources and is made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 70 percent is located at the HTGS and is fired using No. 6 fuel oil. The remaining capacity is located at sites throughout the Island. A complete breakdown of the System's existing capability is provided in table 3-1 below.

Table 3-1

Island Interconnected System Capability – As of June 2008			
	Net Capacity [MW]	Energy [GWh]	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay D'Espoir	592.0	2,272	2,646
Upper Salmon	84.0	492	567
Hinds Lake	75.0	191	220
Cat Arm	127.0	678	667
Granite Canal	40.0	290	339
Paradise River	8.0	33	36
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
Total Hydraulic	927.3	3,961	4,482
Holyrood	465.5	2,996	2,996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	598.2	2,996	2,996
Total NL Hydro	**1,525.5**	**6,957**	**7,478**
Newfoundland Power Inc.			
Hydraulic	92.1	324	423
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	135.6	324	423
Corner Brook Pulp and Paper Ltd.			
Hydraulic	121.4	793	864
AbitibiBowater Inc.			
Hydraulic	58.5	430	467
Non-Utility Generators			
Corner Brook Cogen	15.0	100	100
Exploits River Partnership	32.3	117	137
Rattle Brook	4.0	13	16
Star Lake	15.0	87	141
Total	66.3	317	394
Total Island Interconnected System	**1,907.3**	**8,821**	**9,626**

4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[5].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[6].

5.0 Identification of Need

Table 5-1 presents an examination of the HVDC Link and Isolated Island load forecasts compared to the planning criteria. It does not incorporate Hydro's preliminary expansion plan to show uncommitted generation additions but it does incorporate the committed additions of the St. Lawrence and Fermeuse wind projects scheduled for in-service late 2008. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result of a hydrology adjustment and the use of an integrated system model which determines a more realistic firm system capability. Previously, firm system

[5] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.
[6] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (HTGS) is based on energy capability adjusted for maintenance and forced outages.

capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios being considered. The table shows that under both the HVDC Link and Isolated Island scenarios, capacity (LOLH) deficits start in 2013 and energy deficits start in 2013 for the HVDC Link scenario and 2014 for the Isolated Island scenario. Since the closure of the pulp and paper mill in Stephenville, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

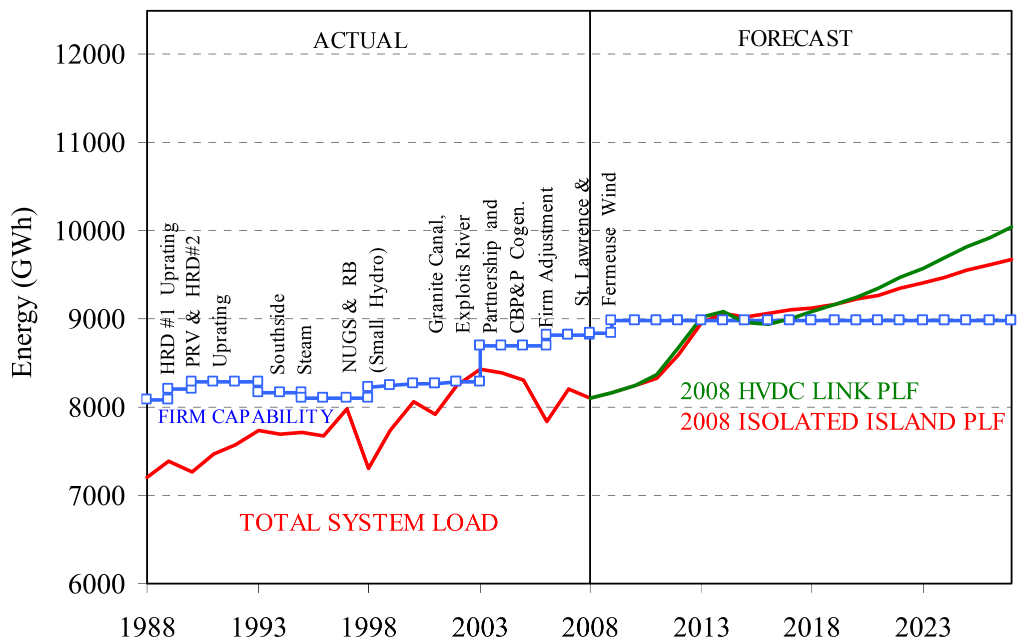
It should be noted that the capacity deficits trigger the need for the next generation source by 2013 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section 7).

Table 5-1 – Load Forecasts Compared to Planning Criteria

	Load Forecasts				Existing System plus 54 MW Wind Power in 2008		LOLH [hr/yr]		Energy Balance [GWh]	
	Maximum Demand [MW]		Firm Energy [GWh]							
Year	HVDC Link	Isolated Island	HVDC Link	Isolated Island	Installed Net Capacity [MW]	Firm Capability [GWh]	HVDC Link	Isolated Island	HVDC Link	Isolated Island
2008	1,566	1,566	8,112	8,112	1,961	8,849	0.46	0.46	737	737
2009	1,582	1,582	8,167	8,167	1,961	8,988	0.39	0.39	821	821
2010	1,600	1,600	8,251	8,251	1,961	8,988	0.55	0.55	737	737
2011	1,622	1,621	8,380	8,332	1,961	8,988	0.86	0.80	608	656
2012	1,652	1,649	8,673	8,606	1,961	8,988	1.66	1.50	315	382
2013	1,721	1,714	9,017	8,955	1,961	8,988	5.28	4.57	-29	33
2014	1,725	1,720	9,079	9,071	1,961	8,988	5.90	5.54	-91	-83
2015	1,730	1,726	8,970	9,022	1,961	8,988	5.48	5.61	18	-34
2016	1,724	1,730	8,945	9,064	1,961	8,988	4.97	5.92	43	-76
2017	1,724	1,738	9,009	9,097	1,961	8,988	5.38	6.79	-21	-109

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the HVDC Link and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

Figure 5-1
Island Interconnected System Capability vs. Load Forecast



6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules; the current status of capital cost estimates; issues of bringing an alternative into service; and other issues related to generation expansion analysis.

6.1 Island Pond

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 186 GWh and 201 GWh, respectively.

The development would include the construction of a 3 kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, and then onto the intake and powerhouse finally discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

Schedule and Cost Estimate

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date.

6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

The project requires: a 320 metre long diversion canal; three concrete dams; a 2,900 metre long penstock; a 27-kilometre-long 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Schedule and Cost Estimate

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units.

6.3 Round Pond

Round Pond is a proposed 20 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

Schedule and Cost Estimate

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule.

6.4 Wind Generation Projects

Newfoundland and Labrador has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. Pending further review and eventual operating experience, a maximum of 80 MW from wind is considered economically and technically acceptable as alternatives to meet a portion of the generation requirements for the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence and in December 2007 it signed a second PPA for another 27 MW of wind power located at Fermeuse. These projects have begun construction and are expected to be in-service by December 2008.

Each wind farm could potentially consist of a number of interconnected wind turbines; each ranging is size from 1.8 to 3.0 MW, tied to a single delivery point on the System's transmission network. For example, a 25 MW wind farm could consist of eight turbines and, depending on the location's wind resource, produce an estimated annual firm and average energy capability of approximately 70 and 110 GWh, respectfully.

Hydro would not develop wind-based projects strictly to address capacity deficits due to the inability to selectively dispatch turbines during periods of high demand. However, these projects do carry some inherent capacity value based on their positive influence on the LOLH calculation and could possibly defer the need for other new generation sources.

Schedule and Cost Estimate

Wind projects typically require at least six to eight months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery. Presently, the System's first two wind projects are expected to be in-service by December 2008.

6.5 Combined Cycle Plant (CCCT)

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on light oil, a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered and estimates have been prepared based on two different power ratings at each site. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood.

In either alternative, the power ratings being considered are either a 125 MW or a 170 MW (net) combined-cycle combustion turbine (CCCT) facility. The annual firm energy capability is estimated at 986 GWh for the 125 MW option and 1,340 GWh for the 170 MW option.

Schedule and Cost Estimate

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant is based on the *Combined Cycle Plant Study Update, Supplementary Report* which was completed in 2001.

6.6 HTGS Unit IV

HTGS Unit IV is a 142.5 MW (net) conventional steam unit fired on heavy oil and is based on similar technology as the three existing HTGS units. The unit would be located at the HTGS adjacent to the existing units. The annual firm energy capability is estimated at 936 GWh.

Schedule and Cost Estimate

It is expected that the HTGS Unit IV project would require, at a minimum, an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule is estimated to be approximately 51 months from the project release date to the in-service date.

Sensitivity analysis has demonstrated that the capital cost of the proposed HTGS Unit IV project would have to drop by approximately 20 percent to be competitive with the combined-cycle option given that environmental mitigation requirements, which would be required for this facility, will increase the cost of such a facility. It is highly unlikely that this option would be competitive with a combined-cycle option. Therefore, Hydro will continue to include the proposed HTGS Unit IV project in its portfolio of alternatives but the cost estimate should be updated, in detail, when the appropriate sensitivity analysis identifies the project as a potential near-term addition.

6.7 Combustion Turbine Units (CT)

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations or at greenfield locations. They are fired on light oil and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh.

Schedule and Cost Estimate

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for these units was reviewed and updated in March 2008, by Hydro's Mechanical Engineering Department. Approximately 90 percent of the direct cost is for the gas turbine package and due to the recent demand for gas turbines; prices remain volatile. Hydro should continue to monitor turbine prices to determine when a further in-depth review of the capital cost estimates becomes necessary.

6.8 High-Voltage Direct Current (HVDC) Link

As part of the potential development of the lower Churchill River, a HVDC link would be constructed to the Island to replace power and energy required from the HTGS and to help meet the future energy requirements of the Island. The schedule and capital cost estimate for this project is currently under development.

7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *NewEnergy Strategist*® software to plan the generation requirements of the System for a given load forecast. *Strategist* is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection costs simulation and generation expansion planning analysis.

The expansion scenarios presented are considered preliminary and they have not been submitted for approval by the Board of Commissioners of Public Utilities (Board). In the Province's 2007 Energy Plan, Hydro has been directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option is based on replacing the HTGS with energy from the lower Churchill River development via a HVDC Link to the Island. The second option is based on an isolated System and is similar to present day operations but the HTGS environmental concerns will be addressed via the addition of scrubbers and electrostatic precipitators. These two options have been named for the purposes of this report as the HVDC Link scenario and the Isolated Island scenario

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio. For this analysis, the two committed 27 MW wind projects that are expected to be in service by December 2008 have been included.

The generation expansion analysis uses an 8.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2008. Other key economic parameters necessary to quantify the long-term costs of alternate generation expansion plans are summarized in Appendix B.

Based on the study assumptions outlined previously, the least-cost[7] generation expansion plan, under the two scenarios, is shown below in Table 7-1 and graphically in Figures 7-1 and 7-2. Under both scenarios, generation from wind-based sources continues as the next preferred source from amongst Hydro's identified portfolio of resource options.

Wind is preferred under both scenarios due to the benefits of fuel displacement and emissions reductions at the HTGS. Also, the wind project positively affects the LOLH calculation. Without this wind project, Hydro may need additional generation sources, beyond what has been identified in the table below, for capacity and energy requirements under both scenarios. The final decision on whether or not to proceed with a wind project will require some deeper analysis to determine the optimal timing, and size of a potential project.

Under the HVDC scenario, after the third wind project in 2010 the next preferred source would be a 50 MW CT in 2012. This CT is needed to satisfy Hydro's capacity (LOLH) planning criteria and will serve to provide some firm energy, if needed, until the HVDC Link is operational in late 2014. As part of the HVDC Link project, several CTs would be required to protect the System's reliability in the event of a prolonged HVDC Link outage. Once the HVDC Link is operational, this newly built CT would revert to a standby status and serve as a backup to the HVDC Link. In late 2014, the link would be put in-service and this would provide Hydro's system capability requirements well beyond the horizon of this expansion analysis.

Under the Isolated Island scenario, following the third wind project in 2010, the next least-cost supply options, in increasing order of cost, are the indigenous hydroelectric plants of Portland Creek in 2012, Island Pond in 2014 and Round Pond in 2016 followed by a 170 MW CCCT plant in 2022 and a 50 MW CT in 2025. The CCCT plant is indicative of the most economic thermal plant, which the Island would require in the long-term for firm capability as an isolated system.

[7] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

For the Isolated Island scenario, further additions of thermal-electric plants can be expected post 2027. Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period.

While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review. These, and other issues, are discussed further in the following section.

Table 7-1

2008 Generation Expansion Plans (Preliminary)		
Year	HVDC Link Scenario Hydro's Alternatives + Wind (Capacity/Firm Capability)	Isolated Island Scenario Hydro's Alternatives + Wind (Capacity/Firm Capability)
2008	SL Wind (27 MW/92 GWh) & FM Wind (27 MW/74.7 GWh)[8]	
2009		
2010	Wind (25 MW/77.2 GWh)	Wind (25 MW/77.2 GWh)
2011		
2012	CT (50 MW/394.2 GWh)	Portland Creek (23 MW/99 GWh)
2013		
2014	HVDC Link	Island Pond (36MW/186 GWh)
2015		
2016		Round Pond (18 MW/108 GWh)
2017		
2018		
2019	SVL Retired	
2020	HWD Retired	
2021		
2022		CCCT (170 MW/1,340 GWh)
2023		HWD & SVL Retired
2024		
2025		CT (50 MW/394.2 GWh)
2026		
2027		
Note: The HVDC Link expansion plan satisfies Hydro's generation planning criteria well beyond the 2027 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2031 (estimated).		

[8] These projects have been committed to by execution of power purchasing agreements in 2007. Therefore, they are common to both expansion plans.

Figure 7-1
Preliminary HVDC Link Expansion Plan vs. Load Forecast

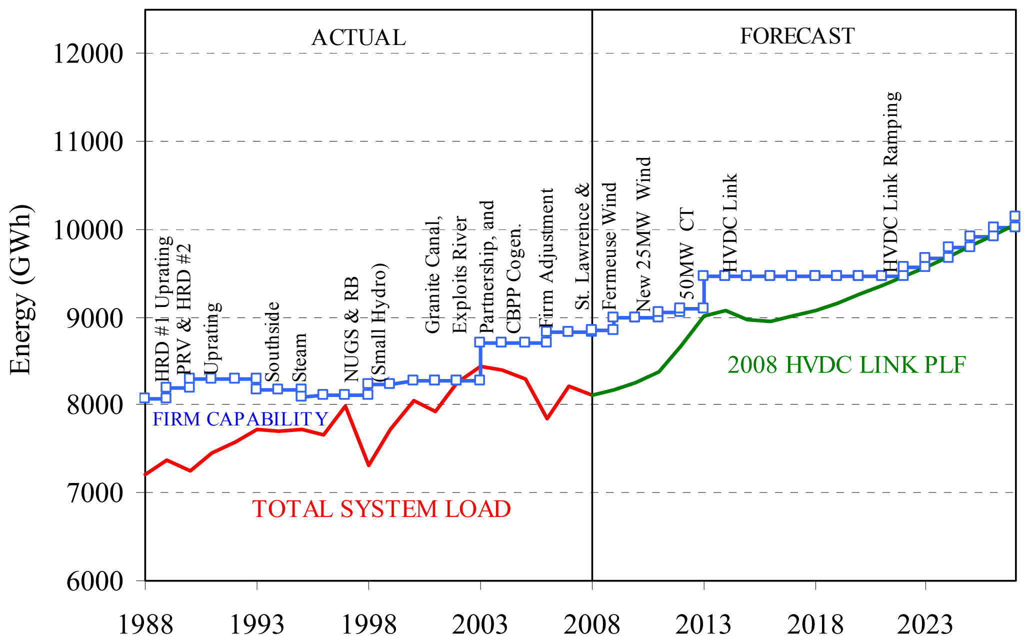
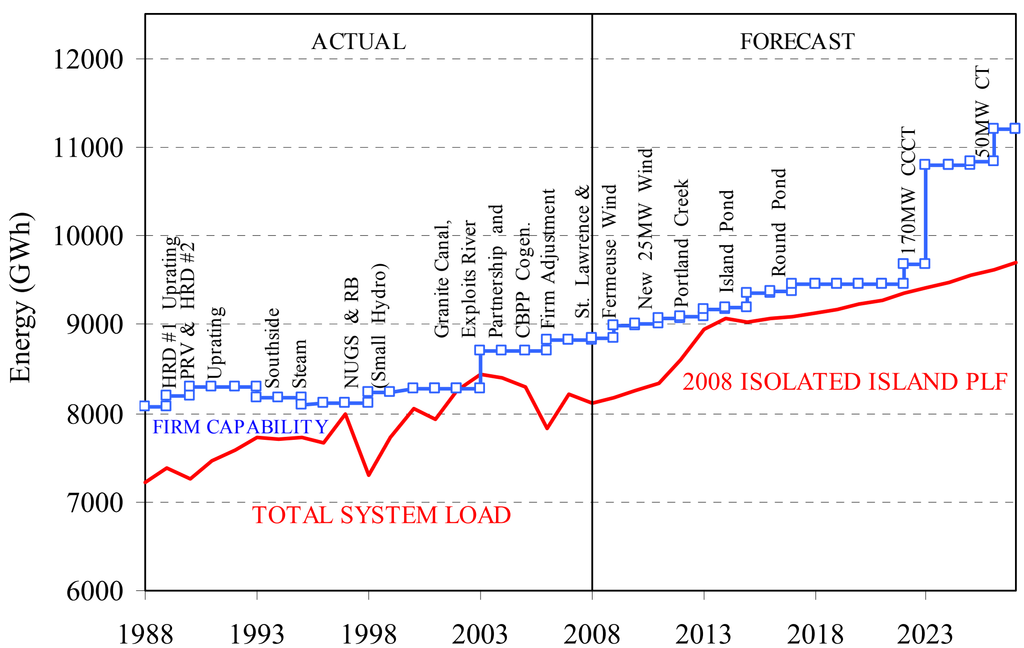


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 The Board of Commissioners of Public Utilities

Prior to 1996, Hydro was not required to seek approval from the Board for its capital program. With the 1996 amendments to the Hydro Corporation Act, and in the absence of a Government exemption, Hydro must seek Board approval before committing to a new generation project.

8.2 Decision Timing

Based on this most recent generation expansion analysis for both the 2008 HVDC Link and Isolated Island forecasts, 54 MW of wind generation has been committed and will be coming online in late 2008. The next requirement for additional generation is in 2012 to avoid exceeding the LOLH criterion in 2013.

Assuming an additional 25 MW wind project is added by 2010; Hydro would have to initiate the project in late 2008 or early 2009 to meet the in-service date. As indicated in the preliminary expansion plan (Table 7-1), the next generation source after the wind project, under both scenarios, would be required in-service in 2012.

Hydro would have to initiate the generation expansion project in 2009 in order to meet the required in-service date for either a 50 MW combustion turbine under the HVDC scenario or the 23 MW Portland Creek hydroelectric plant under the Isolated Island scenario. The 2009 decision will require clarity regarding the future path, whether the HVDC Link will be a reality or the Island will continue as an isolated system. The current plan for the HVDC Link anticipates a project sanction in 2009; however, this schedule is currently under review and delays in the sanction date will have implications for the 2009 generation expansion decision. It is hoped some of this uncertainty will be resolved by the end of 2008 and the result reflected in the year end review.

In the past, it had been assumed that Hydro would initiate an RFP process to identify potential non-utility alternatives to be included in the final portfolio of projects that would be evaluated to determine the optimum expansion plan. However, given the tight timelines associated with the HVDC Link decision and the requirement for additional generation capacity by 2012 there may not be sufficient time to conduct an RFP process. The practicality of conducting an RFP process will be revisited in the year end review.

9.0 Other Issues

9.1 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current 25,000 tonnes per year limitation on sulphur-dioxide (SO_2) emissions from the HTGS, have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the lower Churchill River and a HVDC Link to the Island, or install capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began sourcing 1% sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for 1% sulphur over 2% sulphur fuel oil, this improvement in fuel grade has reduced SO_2 emissions by some 50 percent.

SO_2 is the one of the necessary compounds to form acid rain. Exposure can also have negative health effects, especially for those with respiratory illness. Hydro has also participated in studies to evaluate and communicate to Government the potential impact of proposed changes in environmental regulations. These proposed regulations are aimed at further reducing the amount of sulphur that Hydro will be permitted to emit.

Beyond these considerations, there remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon-dioxide (CO_2) is the primary greenhouse gas and Hydro, by virtue of its Holyrood thermal operations, is a principal emitter in the Province at an average of 1.1 million tonnes per year[9]. In the absence of a transmission link to the North American grid, the long-term incremental energy supply for the Island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions.

For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing, especially under the Isolated Island scenario. Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions.

9.2 HTGS End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under a HVDC Link future, these units will be required to function as synchronous condensers to provide System voltage support. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional

[9] Based on the 5-year average of 1,101,872 tonnes per year of CO_2 from 2003 through 2007.

generation sources. Hydro should be prepared to determine what is required for the HTGS to function until its anticipated end of life under both expansion scenarios.

9.3 Energy Conservation

In June 2008, Hydro along with Newfoundland Power presented to the Board the *Five-Year Energy Conservation Plan*. The plan provides an overview of the current conservation marketplace in the Province of Newfoundland and Labrador, and outlines the strategy to be implemented by Newfoundland and Labrador Hydro and Newfoundland Power for joint conservation activities. The plan also outlines technologies, programs, supporting elements and cost estimates that support a long-term goal of development of a conservation culture and sustainable reduction in electricity consumption. Delivery of these programs is scheduled to commence in 2009. The total estimated energy savings through 2013 under this plan are 79 GWh per year. In all likelihood, the energy conserved will not delay the need for additional generation; however, Hydro should continue to assess its impact on the PLF and expansion plans.

10.0 Conclusion

Based on an examination of the System's existing plus committed capability, in light of the 2008 PLF and the generation planning criteria, the Island system can expect capacity deficits starting in 2013 under both the HVDC Link and Isolated Island scenarios and energy deficits starting in 2013 under the HVDC Link scenario and 2014 under the Isolated Island scenario.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until the decision whether or not to sanction the Lower Churchill Project can be reached. These two expansion plans differ based on the inclusion of a HVDC Link as an available alternative to meet the System's energy requirements. The Lower Churchill Project is scheduled to be sanctioned in 2009 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. Until that time, it would be desirable to avoid committing to one generation expansion plan over another; however, Hydro must be prepared to react to protect the reliability of energy supply for the Provincial market. If a revised forecast indicates that a decision is required prior to the Lower Churchill Project sanctioning, a detailed study on how best to proceed will have to be prepared to ensure that the most appropriate decision can be undertaken in an orderly process.

In order to meet the deficits noted in 2013, Hydro has identified two possible generation sources. The preferred source depends whether or not the Lower Churchill Project will be sanctioned. Assuming that the project is sanctioned, Hydro will likely proceed with the development of a 50 MW combustion turbine in order to satisfy its capacity and energy requirements until the HVDC Link can be established. However, if the project fails to be sanctioned, Hydro will likely require the construction of the 23 MW Portland Creek hydroelectric plant to meet its capacity requirements. It is likely that the remaining hydroelectric facilities of Island Pond and Round Pond would also be constructed for their capacity and energy benefits along with their economic and environmental benefits associated with the displacement of fuel required to produce energy at the HTGS. The decision between these two projects will be required in 2009 in order to meet their respective in-service dates.

Also, in late 2008, two 27 MW wind projects will come online. These projects have a positive influence on the capacity calculation; however, their main benefits are in terms of firm energy production, influence on the System energy balance table and environmental and economic benefits of reducing emissions from burning fuel at the HTGS. A third wind project is expected in 2010 for similar reasons; however, no final decision has been made on whether or not to proceed with this project at this time. The final evaluation and decision whether or not to proceed is expected later in 2008 or early in 2009.

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on HTGS produced electricity and that the timing for the next decision will be unaffected.

The potential impacts of any further production declines in the pulp and paper industry and the potential addition of an oil refinery have not been included as a part of this analysis due to the uncertainty associated with these events. At the appropriate time, perhaps during the usual timeframe for completion of this annual report on Generation Planning Issues, more information may be available on the future direction of these possible events and facilitate their inclusion into this report. As time moves on, and annual updates to this report are prepared, the timing of future generation projects will become more apparent.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVDC Link – Hydro must be prepared to react if the proposed Lower Churchill Project is delayed or fails to receive sanction;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both an Isolated Island and HVDC Link future;
- Emissions control considerations – Hydro must remain vigilant in considering the impact that environmental initiatives could have on production costing and future planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling due to increased environmental scrutiny in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept and costs.

Appendix A

Table A-1
2008 Planning Load Forecasts

Year	2008 PLF HVDC Link Case		2008 PLF Isolated Island Case	
	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]
2008	1,566	8,112	1,566	8,112
2009	1,582	8,167	1,582	8,167
2010	1,600	8,251	1,600	8,251
2011	1,622	8,380	1,621	8,332
2012	1,652	8,673	1,649	8,606
2013	1,721	9,017	1,714	8,955
2014	1,725	9,079	1,720	9,071
2015	1,730	8,970	1,726	9,022
2016	1,724	8,945	1,730	9,064
2017	1,724	9,009	1,738	9,097
2018	1,739	9,082	1,745	9,124
2019	1,756	9,166	1,752	9,175
2020	1,773	9,253	1,762	9,223
2021	1,792	9,353	1,772	9,280
2022	1,814	9,466	1,785	9,355
2023	1,835	9,577	1,797	9,421
2024	1,857	9,696	1,809	9,479
2025	1,880	9,814	1,821	9,547
2026	1,903	9,929	1,833	9,613
2027	1,926	10,051	1,846	9,689

Appendix B

Table B-1
Fuel Forecast

Year	Residual 1.0%S (6.287 MBTU/BBL) [$/BBL]	Diesel (5.825 MBTU/BBL) [$/litre]
2008	99.90	1.045
2009	86.90	0.815
2010	91.20	0.745
2011	88.00	0.710
2012	88.70	0.715
2013	92.70	0.745
2014	94.60	0.765
2015	96.60	0.785
2016	98.50	0.805
2017	100.80	0.825
2018	103.00	0.845
2019	105.20	0.865
2020	107.50	0.885
2021	109.70	0.900
2022	112.00	0.920
2023	114.40	0.940
2024	116.70	0.960
2025	119.20	0.980
2026	121.70	1.000
2027	124.20	1.020

Source: NL Hydro, Market Analysis Section, June 2008

Table B-2
Escalation Rates

Year	General Inflation		Construction			Operation & Maintenance	
	GDP	Canadian CPI	Hydro & Thermal Plant	Transmission Line	Transformer Station	More Materials Less Labour	More Labour Less Materials
2008	2.5%	2.5%	3.0%	2.5%	2.0%	2.5%	3.0%
2009	2.0%	2.0%	3.0%	2.5%	2.0%	2.5%	3.0%
2010	2.0%	2.0%	3.0%	2.5%	2.0%	2.5%	3.0%
2011	2.0%	2.0%	3.0%	2.5%	2.5%	2.5%	3.0%
2012	2.0%	2.0%	3.0%	2.5%	2.5%	2.5%	3.0%
Beyond 2012	2.0%	2.0%	3.0%	3.0%	2.5%	2.5%	3.0%

Source: NL Hydro, Market Analysis Section, October 2007

Table B-3
Future Resource Capital Cost Flow Estimates

Project	Direct Costs in January 2008$ (x 1,000)*					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Island Pond	4,808	40,073	53,550	64,434		162,865
Round Pond	11,827	65,913	61,584			139,323
Portland Creek	3,805	19,557	64,732			88,094
Hardwoods 50 MW CT	611	15,239	44,376			60,226
Stephenville 50 MW CT	611	15,792	45,995			62,397
Greenfield-1 50 MW CT	676	17,259	46,605			64,540
Greenfield-2 50 MW CT	613	15,491	45,177			61,280
Holyrood 125 MW CCCT	23,937	91,586	62,147			177,670
Holyrood 175 MW CCCT	27,838	108,946	65,842			202,625
Greenfield 175 MW CCCT	6,132	74,522	102,515	86,018		269,188
HTGS Unit IV	9,356	73,392	123,028	92,662		298,438
Wind 27 MW	18,000	36,000				54,000

* Excludes Escalation and Interest During Construction

GENERATION PLANNING ISSUES
2010 JULY UPDATE

System Planning Department
July 2010

REGISTERED PROFESSIONAL ENGINEER
R. J. H. MOULTON
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2010-07-16
DATE
PROVINCE OF NEWFOUNDLAND

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hydro
a nalcor energy company

Executive Summary

This report provides an overview of the Island Interconnected System (System) generation capability, the proposed timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be considered to ensure that a decision on the preferred source can be made through an orderly and cost-effective process.

The Province's 2007 Energy Plan outlines specific measures to address environmental concerns related to the Holyrood Thermal Generating Station (HTGS). The long-term plan proposed in the Energy Plan is to replace the energy provided by the HTGS with electricity from the Lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island. In the event the Lower Churchill Project does not proceed, scrubbers and precipitators are to be installed at the HTGS. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two preliminary generation expansion plans; one for the HVdc link and one for the Isolated Island scenario. Under both scenarios based on an examination of the System's existing plus committed capability, in light of the 2010 Planning Load Forecast (PLF) and the generation planning criteria, capacity (Loss of Load Hours (LOLH)) deficits start in 2015. There are no energy deficits in either case until post-2019.

In order to protect the in-service date for the Island Pond hydroelectric development alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, under an Isolated Island scenario, the addition of a Request for Proposal (RFP) process necessitates a decision to proceed in late 2010 to meet an in-service date of fall 2015. This is due to the need to complete the RFP evaluation and subsequent Newfoundland and Labrador Board of Commissioners of Public Utilities (Board) review and have a final decision by spring 2012.

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.
- Demand reduction initiatives through demand management programs and rate design considerations

Table of Contents

1.0 Introduction

This report provides an overview of the Island Interconnected System (System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be considered to ensure that a decision on the preferred source can be made through an orderly process.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). Option A was to replace HTGS produced electricity with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the Island. Option B was to install scrubbers and electrostatic precipitators to control emissions at the HTGS and maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on HTGS produced electricity. These two options require significantly different strategies to effectively implement and require the development of two separate, preliminary, generation expansion plans to manage the near-term until a decision is made on which option will be pursued for future development.

This report addresses the timing of the next requirement, in light of the most recent load forecast, for additional generation supply under both options and the resources available to meet that requirement. The report also identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly and cost-effective process.

2.0 Load Forecast

This review utilizes the 2010 Planning Load Forecast (PLF) as prepared by the Market Analysis section of Hydro's System Planning Department during the winter of 2009/2010. Long-term load forecasts for the Province are derived using Hydro's own electricity demand models and are driven by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. Some key assumptions respecting existing and incremental economic activity impacting electricity demand and supply futures are:

- Single Island newsprint operation at Corner Brook and single Island oil refining operation at Come by Chance;
- Vale Inco NL nickel processing facility at Long Harbour with initial connection in late 2011 and commercial production occurring across the 2013[1] to 2014 period;
- Teck Resources Limited mining operations at Duck Pond continuing through 2013[2]; and
- Development of the Hebron oil field.

Growth rate summaries of the salient high-level economic indicators for the province as forecast by the provincial Department of Finance are presented in Table 2-1.

[1] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[2] Teck Cominco 2007 Annual Report.

Table 2-1

Provincial Economic Indicators – 2010 PLF			
	2009-2014	**2009-2019**	**2009-2029**
Adjusted Real GDP at Market Prices* (% Per Year)	1.5%	1.0%	0.9%
Real Disposable Income (% Per Year)	1.5%	1.0%	0.9%
Average Housing Starts (Number Per Year)	2575	2400	2135
End of Period Population (‘000s)	515	510	507
*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.			

Hydro is responsible for the generation planning for the System and that includes the power and energy supplied by Hydro’s customer-owned-generation resources in addition to Hydro’s bulk and retail electricity supply, including power purchases. The projected electricity growth rates for the System are presented in Table 2-2.

An important source of load growth for the utility sector on the Island continues to be the unwavering preference for electric water heating systems along with a majority preference for electric space heating across residential and commercial customers. For Hydro’s existing industrial customers, single newsprint mill and oil refinery operations are maintained with the Teck Resources mine expected to operate through 2013. The Vale Inco NL nickel processing facility is scheduled to be provided a transmission connection in late 2011 with commercial production expected in the 2013 to 2014 time frame.

Table 2-2

Electricity Load Growth Summary – 2010 PLF			
	2009-2014	**2009-2019**	**2009-2029**
Utility[1]	1.8%	1.2%	1.2%
Industrial[2]	7.1%	3.8%	1.9%
Total	2.7%	1.7%	1.3%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. AbitibiBowater ceased production of newsprint at its Grand Falls mill in February 2009. Industrial load post 2009 is the summation of Corner Brook Pulp and Paper, North Atlantic Refining, Teck Resources and Vale Inco NL

Table 2-3 provides a summary of the 2010 PLF electric power and energy requirements for the System for the period 2010 to 2019. Similar long-term load projections are prepared for the Labrador Interconnected System and for Hydro's Isolated Diesel Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term PLF that was used to complete the generation expansion analysis.

Table 2-3

Electricity Load Summary – 2010 Island PLF						
	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2010	1,342	6,115	190	1,278	1,519	7,585
2011	1,360	6,244	195	1,271	1,538	7,709
2012	1,385	6,292	228	1,362	1,571	7,849
2013	1,400	6,410	276	1,604	1,601	8,211
2014	1,423	6,496	269	1,789	1,666	8,485
2015	1,440	6,551	269	1,853	1,683	8,606
2016	1,452	6,567	269	1,853	1,695	8,623
2017	1,461	6,601	269	1,853	1,704	8,663
2018	1,471	6,670	269	1,853	1,714	8,732
2019	1,486	6,739	269	1,853	1,729	8,803

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses. Demands are coincident peak demands.

3.0 System Capability

Hydro is the primary supplier of system capability to the Island Interconnected System, accounting for 78 percent of its net capacity and 78 percent of its firm energy. Capability is also supplied by customer generation from Newfoundland Power Inc., and Corner Brook Pulp and Paper Limited (Kruger Inc.) Hydro also has contracts with two Non-Utility Generators (NUGs) for the supply of power and energy as well as contracts with two wind power projects that became operational in late 2008 and early 2009. Hydro also receives energy from the expropriated assets at Star Lake and on the Exploits River.

Hydroelectric generation accounts for 64 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from wind farms and thermal resources. The thermal resources are made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 71 percent is located at the HTGS and is fired using 0.7 percent sulphur No. 6 fuel oil. The remaining capacity is located at sites throughout the Island. A complete breakdown of the System's existing capability is provided in Table 3-1.

Table 3-1

Island Interconnected System Capability – As of June 2010			
* - non-dispatchable (see Section 9.1)	Net Capacity [MW]	Energy [GWh] Firm	Energy [GWh] Average
Newfoundland & Labrador Hydro			
Bay d'Espoir	592.0	2,272	2,629
Upper Salmon	84.0	492	561
Hinds Lake	75.0	290	343
Cat Arm	127.0	678	710
Granite Canal	40.0	191	223
Paradise River	8.0	33	37
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
Total Hydraulic	927.3	3,961	4,510
Holyrood	465.5	2,996	2,996
Combustion Turbine	110.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	590.2	2,996	2,996
Total NL Hydro	**1,517.5**	**6,957**	**7,506**
Newfoundland Power Inc.			
Hydraulic*	96.6	324	428
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	140.1	324	428
Corner Brook Pulp and Paper Ltd.			
Hydraulic*	121.4	793	879
Star Lake and Exploits Generation			
Hydraulic*	105.8	634	761
Non-Utility Generators			
Corner Brook Cogen*	15.0	65	65
Rattle Brook*	4.0	13	16
St. Lawrence Wind*	27.0	92	104
Fermeuse Wind*	27.0	75	84
Total	73.0	245	269
Total Island Interconnected System	**1,957.8**	**8,953**	**9,843**

4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[3].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[4].

5.0 Identification of Need

Table 5-1 presents an examination of the HVdc link and Isolated Island load forecasts compared to the planning criteria. It does not incorporate Hydro's preliminary expansion plan to show uncommitted generation additions. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result of a hydrology adjustment and the use of an integrated system model which determines a more

[3] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.
[4] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (HTGS) is based on energy capability adjusted for maintenance and forced outages.

realistic firm system capability. Previously, firm system capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios being considered. The table shows that under both the HVdc link and Isolated Island scenarios, capacity (LOLH) deficits (LOLH exceeding 2.8 hours per year) start in 2015 but that there are no energy deficits in either case until post-2019. Since the closure of the pulp and paper mills in Stephenville and Grand Falls, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

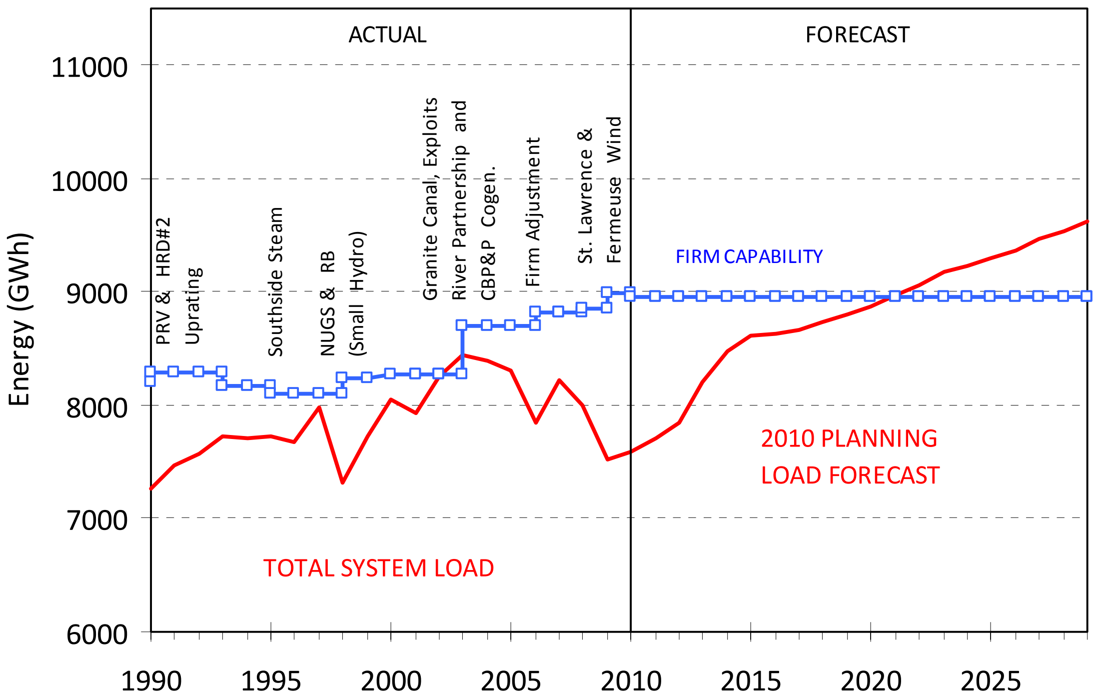
It should be noted that the capacity deficits trigger the need for the next generation source by 2015 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section 7).

Table 5-1 – Load Forecast Compared to Planning Criteria

Year	Island Load Forecast		Existing System		LOLH (hr/year) (limit: 2.8)		Energy Balance (GWh)	
	Maximum Demand (MW)	Firm Energy (GWh)	Installed Net Capacity (MW)	Firm Capability (GWh)	HVdc Link	Isolated Island	HVdc Link	Isolated Island
2010	1,519	7,585	1,958	8,953	0.15	0.15	1,368	1,368
2011	1,538	7,709	1,958	8,953	0.22	0.22	1,244	1,244
2012	1,571	7,849	1,958	8,953	0.41	0.41	1,104	1,104
2013	1,601	8,211	1,958	8,953	0.84	0.84	742	742
2014	1,666	8,485	1,958	8,953	2.52	2.52	468	468
2015	1,683	8,606	1,958	8,953	3.41	3.41	347	347
2016	1,695	8,623	1,958	8,953	3.91	3.91	330	330
2017	1,704	8,663	1,958	8,953	4.55	4.55	290	290
2018	1,714	8,732	1,958	8,953	5.38	5.38	221	221
2019	1,729	8,803	1,958	8,953	6.70	6.70	150	150

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the HVdc link and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

Figure 5-1
Island Interconnected System Capability vs. Load Forecast



6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules; the basis for capital cost estimates; issues of bringing an alternative into service; and other issues related to generation expansion analysis.

6.1 Island Pond

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, and then onto the intake and powerhouse finally discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

Schedule and Cost Estimate Basis

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date.

6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

The project would require: a 320 metre long diversion canal; three concrete dams; a 2,900 metre penstock; a 27 kilometre 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units.

6.3 Round Pond

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule.

6.4 Wind Generation Projects

The Island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence and in December 2007 it signed a second PPA for another 27 MW of wind power located at Fermeuse. Both of these projects are currently generating power into the Island grid. Pending further review and eventual operating experience and with the loss of the load associated with the shutdown of the Grand Falls Pulp and Paper Mill in late 2008, it was decided to postpone a RFP for a third wind farm, as the potential for spill, due to the additional non-dispatchable generation, makes the project economically unattractive (see Section 9.1 Intermittent and Non-Dispatchable Resources).

Any future wind farm would potentially consist of a number of interconnected wind turbines, each ranging in size from 1.8 to 3.0 MW (or larger, as the technology becomes available), tied to a single delivery point on the System's transmission network. For example, a nominal 25 MW wind farm could consist of eight turbines and, depending on the location's wind resource, produce an estimated annual firm and average energy capability of approximately 70 and 110 GWh, respectively.

Hydro would not develop wind-based projects strictly to address capacity deficits due to the inability to selectively dispatch turbines during periods of high demand. However, these projects do carry some inherent capacity value based on their positive influence on the LOLH calculation and could possibly defer the need for other new generation sources.

Schedule and Cost Estimate Basis

Wind projects typically require at least six to eight months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery.

6.5 Combined Cycle Plant

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on light oil (in the absence of natural gas), a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered and estimates have been prepared based on two different power ratings at each site. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood and reduce the risk of loss of multiple generation sources in the event of major events.

In either alternative, the power ratings being considered are either a 125 MW or a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 986 GWh for the 125 MW option and 1,340 GWh for the 170 MW option.

Schedule and Cost Estimate Basis

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant is based on the *Combined Cycle Plant Study Update, Supplementary Report* which was completed in 2001, with a review by Hydro's Mechanical Engineering Department in 2009 and updated to 2010.

6.6 Holyrood Thermal Generating Station Unit IV

HTGS Unit IV is a 142.5 MW (net) conventional steam unit fired on heavy oil and is based on similar technology as the three existing HTGS units. The unit would be located at the HTGS adjacent to the existing units. The annual firm energy capability is estimated at 936 GWh.

Schedule and Cost Estimate Basis

It is expected that the HTGS Unit IV project would require, at a minimum, an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule is estimated to be approximately 51 months from the project release date to the in-service date.

Sensitivity analysis has demonstrated that the capital cost of the proposed HTGS Unit IV project would have to drop considerably compared with the combined-cycle option given that environmental mitigation requirements, which would be required for this facility, will increase the cost of such a facility. As well, GHG emission rates for conventional steam units exceed those for combined-cycle plants, further adding to the cost. It is highly unlikely that this option would be competitive with a combined-cycle option. Therefore, Hydro will continue to include the proposed HTGS Unit IV project in its portfolio of alternatives but the cost estimate should be updated, in detail, when the appropriate sensitivity analysis identifies the project as a potential near-term addition.

6.7 Combustion Turbine Units

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations, at the Holyrood site or at greenfield locations. They are fired on light oil and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh each.

Schedule and Cost Estimate Basis

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for these units was reviewed in 2009, by Hydro's Mechanical Engineering Department and updated in 2010. Approximately 90 percent of the direct cost is for the gas turbine package and due to recent fluctuations in demand for gas turbines; prices remain volatile. Hydro should continue to monitor turbine prices to determine when a further in-depth review of the capital cost estimates becomes necessary.

6.8 High Voltage Direct Current (HVdc) Link

As part of the potential development of the lower Churchill River (Lower Churchill Project), a HVdc link would be constructed to the Island to replace power and energy required from the HTGS and to help meet the future energy requirements of the Island. The schedule and capital cost estimate for this project is currently under development.

7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *Ventyx Strategist®* software to analyse and plan the generation requirements of the System for a given load forecast. *Strategist®* is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis.

The expansion scenarios presented are considered preliminary and they have not been submitted for approval by the Board. In the Province's Energy Plan, Hydro has been directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option is based on replacing the HTGS with energy from the Lower Churchill River development via a HVdc link to the Island. The second option is based on an isolated System and is similar to present day operations but the HTGS environmental concerns of sulphur dioxide (SO_2) and particulate emissions will be addressed via the addition of scrubbers and electrostatic precipitators. The scrubbers and electrostatic precipitators will not address greenhouse gas issues. These two options have been named for the purposes of this report as the HVdc link scenario and the Isolated Island scenario.

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio.

The generation expansion analysis uses an 8.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2010.

Based on the study assumptions outlined previously, the least-cost[5] generation expansion plan, under the two scenarios, is shown below in Table 7-1 and graphically in Figures 7-1 and 7-2.

[5] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

7.1 High-Voltage Direct Current Link Scenario

Under the HVdc link scenario, a 50 MW CT would be planned for 2014. Dependant on environmental assessment approvals, the current schedule could see Lower Churchill Project commissioning and operations in the 2015-2016 timeframe and this would provide Hydro's system capability requirements well beyond the horizon of this expansion analysis. As well, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2022 and 2024, respectively.

7.2 Isolated Island Scenario

Under the Isolated Island scenario, the third wind project would be planned for 2014, in the same time frame the additional load from the Vale Inco NL facility is forecast to come on to the grid, enabling the grid to absorb more non-dispatchable generation. Wind is considered due to the benefits of fuel displacement and emissions reductions at the HTGS. The final decision on whether or not to proceed with a wind project will require further analysis to determine the optimal timing, and size of a potential project.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2015, Portland Creek in 2018, and Round Pond in 2020 followed by a 170 MW CCCT plant in 2022 and 50 MW CTs in 2024 and 2027. The CCCT plant is indicative of the most economic thermal plant for supplying base load, which the Island would require in the long-term for firm capability as an isolated system.

For the Isolated Island scenario, further additions of thermal-electric plants can be expected post 2029. Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period.

While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review and allowing time for proper implementation. These, and other issues, are discussed further in the following section.

Table 7-1

2010 Generation Expansion Plans (Preliminary)		
Year	**HVdc Link Scenario Hydro's Alternatives (Capacity/Firm Capability)**	**Isolated Island Scenario Hydro's Alternatives (Capacity/Firm Capability)**
2010		
2011		
2012		
2013		
2014	CT (50 MW/394.2 GWh)	Wind Farm (25 MW/77 GWh)
2015		Island Pond (36MW/172 GWh)
2016	HVdc link (800 MW)	
2017		
2018		Portland Creek (23 MW/99 GWh)
2019		
2020		Round Pond (18 MW/108 GWh)
2021		
2022	Hardwoods CT retired	CCCT (170 MW/1,340 GWh) Hardwoods CT retired
2023		
2024	Stephenville CT Retired	CT (50 MW/394.2 GWh) Stephenville CT Retired
2025		
2026		
2027		CT (50 MW/394.2 GWh)
2028		
2029		
Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2029 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2033 (estimated).		

Figure 7-1
Preliminary HVDC Link Expansion Plan vs. Load Forecast

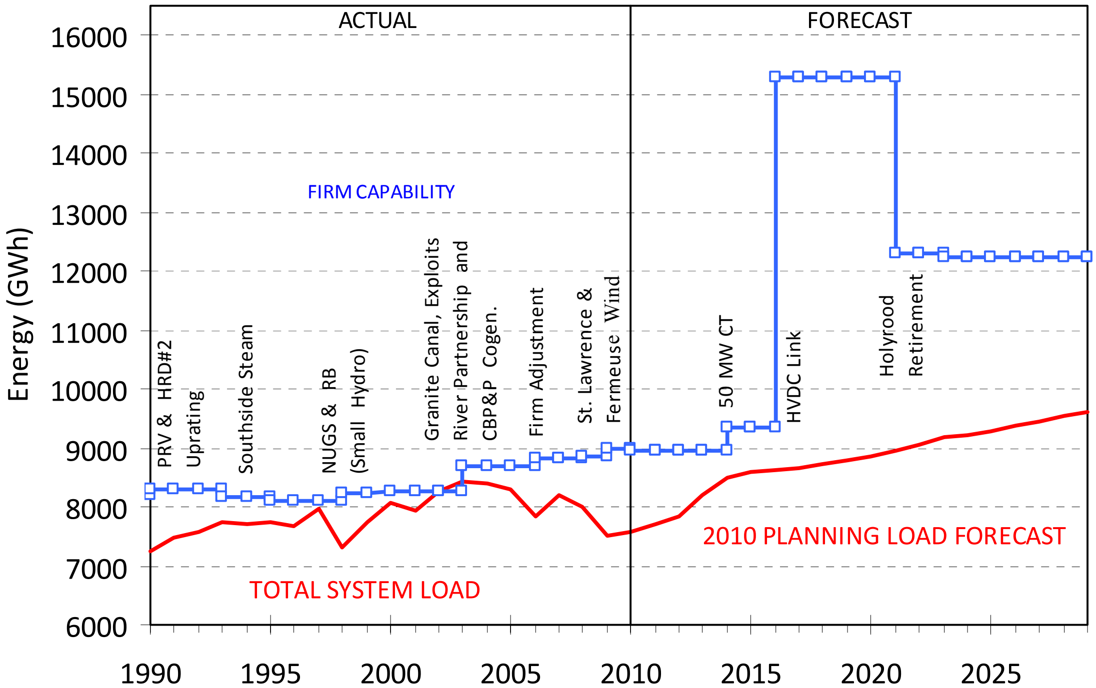
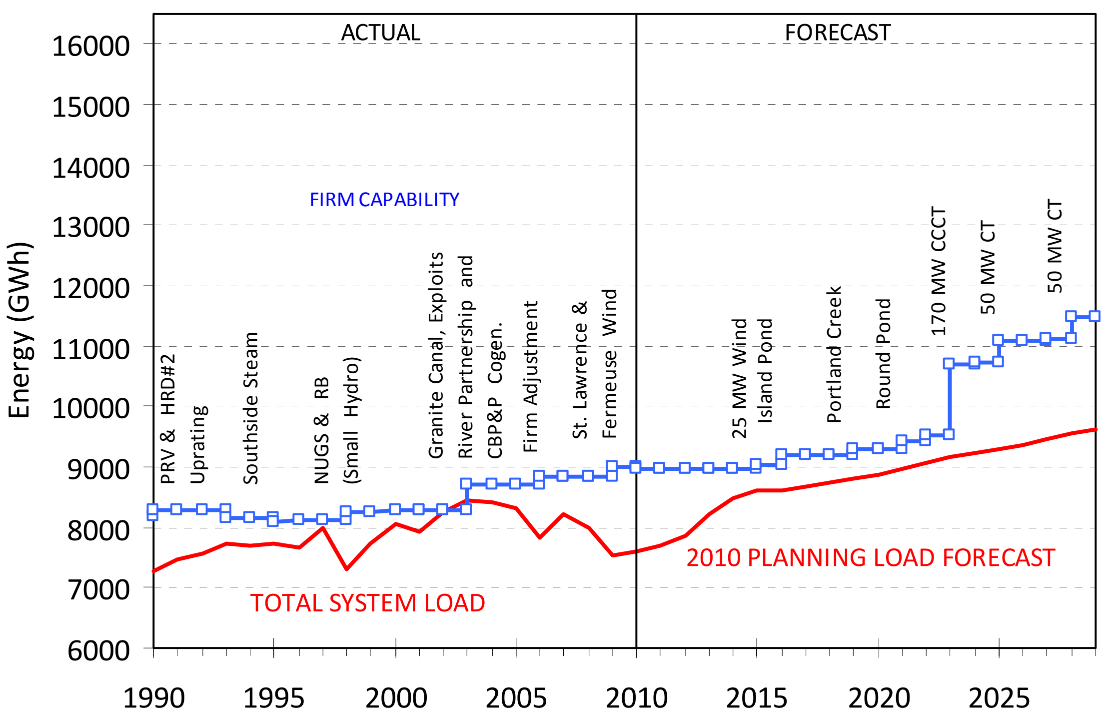


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 Request for Proposals

In addition to those resources included in Hydro's own portfolio of near term alternatives, any number of alternatives may be brought forward under a RFP. As with the 1997 RFP, alternatives submitted under a general RFP can range from various forms of conventional technologies to alternate technologies such as wind power.

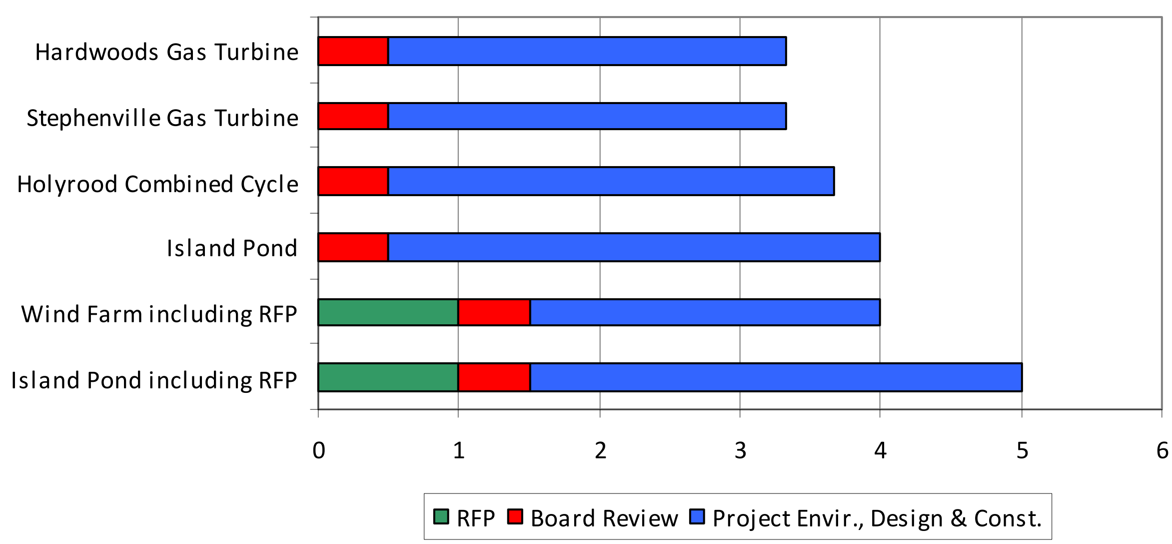
In addition to the time required to bring a project through the normal environmental and construction schedules, additional lead time is required to implement an RFP process. Based on Hydro's 1997 experience, the minimum amount of time required to issue and evaluate proposals through an RFP process is approximately seven months. This was accomplished only through having a high priority placed on the process by the Leadership Team, the commitment of key personnel from various departments and the assistance of consultants. Due to the urgency to have a final report on generation expansion alternatives ready by mid-June 1997, the RFP, issued in mid-January, gave proponents only approximately three months to submit proposals. Many proponents expressed concern about the short time allotted to prepare proposals and it was evident that if more time had been provided, there may have been more submissions. Ideally, the RFP process requires approximately 15 months to complete, as was the case for Hydro's first RFP for small hydro non-utility generators in 1992. An RFP process with a 12 month schedule from issue through to completion of the project evaluations is a reasonable compromise between the accelerated schedule of the 1997 RFP and the much longer 1992 RFP schedule.

8.2 Newfoundland and Labrador Board of Commissioners of Public Utilities

Prior to 1996, Hydro was not required to seek approval from the Board for its capital program. However, with the 1996 amendments to the Hydro Corporation Act, Hydro, in the absence of a Government of Newfoundland and Labrador exemption, must seek Board approval before committing to acquire a new generation project. Given that this process has yet to be tried, approval is estimated to take as long as six months depending on the level of interest shown and the number of interveners requesting standing at the hearings. Based on the level of interest shown at recent Board hearings and as expressed in the 1997 RFP, it is expected that there would be significant interest in a hearing for a new generation source.

Assuming an additional 25 MW wind project is brought in-service by 2014, for fuel displacement at Holyrood, additional generation will be required by the fall of 2015. Based on the requirement for additional generation by the fall of 2015 under an Isolated Island scenario, the following bar chart illustrates the lead times, including that required for a Board review, for each of the near term alternatives to achieve in-service by that time.

Figure 8-1 - Project Lead Times



The addition of an RFP process necessitates a decision to proceed in late 2010 to meet an in-service date of fall 2015. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by spring 2012 to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio.

9.0 Other Issues

9.1 Intermittent and Non-Dispatchable Resources

Based on the Island's existing plus committed generating capacity, approximately 397 MW, or 20 percent of net capacity can be characterized as non-dispatchable generation (see Table 3-1). While energy production from these resources is predictable over the long term, the generation may not be available when needed. The concern with this type of generation comes on two fronts; first in the availability of the generation to meet higher loads; and second on occasions of light load when the non-dispatchable capacity can no longer be absorbed into the system without adverse technical and economic impacts.

From a generation planning point of view, when assessing the adequacy of system resources to meet peak demands, the characteristics of non-dispatchable generation are incorporated into the unit models. Therefore, on a go-forward basis, new non-dispatchable resources are appropriately evaluated in generation capacity planning analyses.

However, long-term generation planning may not necessarily capture the short-term operational constraints of intermittent and non-dispatchable resources, particularly those related to the ability of the system to absorb the capacity under light load periods. As more and more intermittent and non-dispatchable capacity is added to the system, there comes a point at which the ability to maintain stability and acceptable voltages throughout the system may be compromised. As well, there is an increased risk of spilling during high inflow periods as hydraulic production is reduced to accept non-dispatchable production.

In advance of any future RFP that would likely feature non-dispatchable resources such as small hydro and wind energy, it is necessary to determine what limitations on non-dispatchable resources are appropriate. While this has been studied a number of times, changes in available generation and load, such as the Grand Falls paper mill ceasing operations, necessitates a revisting of the analysis. In this light it is recommended that System Planning, in cooperation with Generation Operations, continue to conduct studies to identify the amount of non-dispatchable capacity that may be added without adversely affecting the operation of the system. Changes in these areas may affect proposals in an RFP process in the context of the type of proposal and price.

9.2 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current Provincial Government 25,000 tonnes per year limitation on SO_2 emissions from the HTGS, have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the lower Churchill River and a HVdc link to the Island, or install capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began burning one percent sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for one percent sulphur over two percent sulphur fuel oil, this improvement in fuel grade has reduced SO_2 and other emissions by about 50 percent. In 2009, Hydro further switched to 0.7 percent sulphur fuel, which may reduce SO_2 and other emissions by a further 30 percent.

There remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas of concern and Hydro's Holyrood Plant emits an average of approximately 866,000 tonnes per year[6] of CO_2. In the absence of a transmission link from Labrador to the Island, the long-term incremental energy supply for the Island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions. It is pertinent to note that the addition of scrubbers and precipitators to the Holyrood Plant will not reduce CO_2 emissions.

For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario.

Other emissions that may come under further regulation include nitrogen oxides (NO_x) and particulate.

Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions. As well, Hydro is closely monitoring national and international activity in this area.

[6] Based on the 5-year average of 866,158 tonnes per year of CO_2 from 2005 through 2009.

9.3 Holyrood Thermal Generating Station End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under a HVdc link future, these units will be required, as a minimum, to function as synchronous condensers to provide System voltage support as well as to provide a backup supply for some period after the HVdc link comes in-service. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating reliably until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional generation sources. Hydro must determine what is required for the HTGS to function until its anticipated end of life under both expansion scenarios and to facilitate this, the Board has approved a Condition Assessment of the facility, which is currently being carried out.

9.4 Energy Conservation

The takeCHARGE residential rebate programs for insulation, thermostats and ENERGY STAR® windows have had increasing uptake since their launch and are now in the market for a full year. Work is now underway to explore expanded technologies for additional rebate programs. The Commercial Lighting program was launched in 2009 and discussions continue with the Province and other key players in the commercial lighting market to ensure participation in the program and identification of opportunities for inclusion of high efficiency lighting in their purchase specifications. The Industrial Energy Efficiency program will be launched in 2010. In addition to the rebate programs, work continues on outreach and awareness efforts with customers, retailers and builders to ensure participation in the programs.

As well in 2009 Hydro partnered with the Provincial Department of Natural Resources to deliver a community based energy efficiency program in two Coastal Labrador communities. This project was a pilot to explore the impact of community based interventions on energy efficiency. It was very successful, providing efficiency tools, local job opportunities and promotions and awareness to increase the knowledge base and assist residents in taking immediate action on efficiency.

10.0 Conclusion

Based on an examination of the System's existing plus committed capability, in light of the 2010 PLF and the generation planning criteria, the Island system can expect capacity deficits starting in 2015 under both the HVdc link and Isolated Island scenarios but no energy deficits until post-2019.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until a sanction decision on the Lower Churchill Project can be reached. These two expansion plans differ based on the inclusion of a HVdc link as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Lower Churchill Project is scheduled for 2010 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. Until that time, it would be desirable to avoid committing to one generation expansion plan over another; however, Hydro must be prepared to react to protect the reliability of energy supply for the Provincial market. If a revised forecast indicates that a decision is required prior to the Lower Churchill Project sanctioning, a detailed study on how best to proceed will have to be prepared to ensure that the most appropriate decision can be undertaken in an orderly process.

In order to meet the deficits noted in 2015, Hydro has identified two possible sources. The preferred source depends whether or not the Lower Churchill Project and the HVdc link are sanctioned. Assuming that the Project and link are sanctioned, a 50 MW CT will be required in 2014, and then the HVdc link will meet the capacity and energy requirements of the Island for many years to come. However, if the Project and link are not sanctioned, Hydro will likely require the construction of the 36 MW Island Pond hydroelectric plant to meet its capacity requirements, as well as a third wind farm. It is likely that the remaining hydroelectric facilities of Portland Creek and Round Pond would also be constructed for their capacity and energy benefits along with their economic and environmental benefits associated with the displacement of fuel required to produce energy at the HTGS. In order to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, the addition of a RFP process for other supplies necessitates a decision to proceed in late 2010 to meet an in-service date of fall 2015. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by spring 2012.

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on HTGS produced electricity and that the timing for the next decision will be unaffected.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;

- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.

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Appendix A

Table A-1
2010 Island Planning Load Forecast

Year	Maximum Demand [MW]	Firm Energy [GWh]
2010	1,519	7,585
2011	1,538	7,709
2012	1,571	7,849
2013	1,601	8,211
2014	1,666	8,485
2015	1,683	8,606
2016	1,695	8,623
2017	1,704	8,663
2018	1,714	8,732
2019	1,729	8,803
2020	1,744	8,869
2021	1,757	8,965
2022	1,776	9,062
2023	1,794	9,169
2024	1,813	9,232
2025	1,827	9,290
2026	1,840	9,372
2027	1,856	9,461
2028	1,872	9,543
2029	1,888	9,623