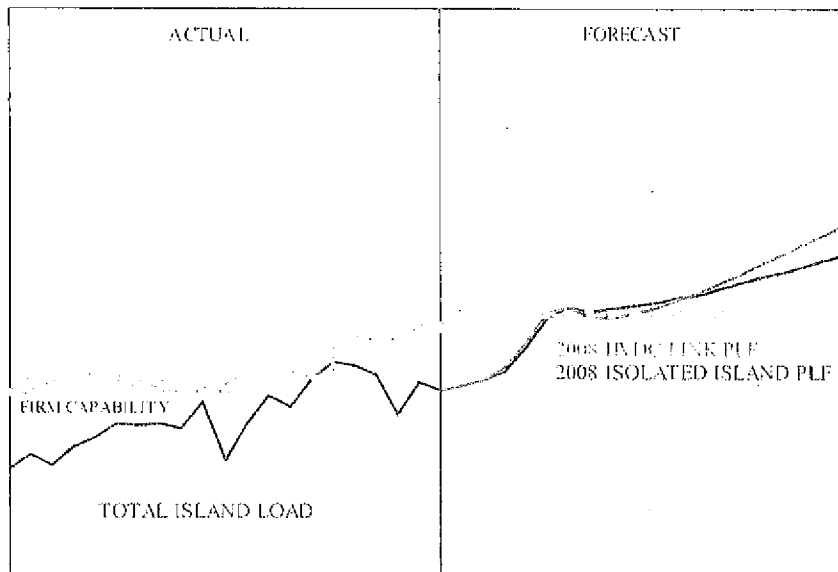




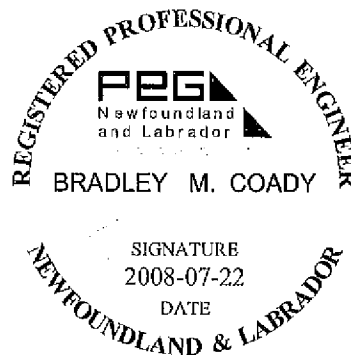
Generation Planning Issues

2008 Mid Year Update



System Planning

July 2008



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.

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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 Brook¹ and Grand Falls;
- Single Island oil refining operation at Come by Chance;
- Start-up of the Vale Inco NL² nickel processing facility on the Island in 2012;
- Teck Cominco³ 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
<u>Newfoundland & Labrador Hydro</u>			
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	<u>927.3</u>	<u>3,961</u>	<u>4,482</u>
Holyrood	465.5	2,996	2,996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	<u>598.2</u>	<u>2,996</u>	<u>2,996</u>
Total NL Hydro	<u>1,525.5</u>	<u>6,957</u>	<u>7,478</u>
<u>Newfoundland Power Inc.</u>			
Hydraulic	92.1	324	423
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	<u>135.6</u>	<u>324</u>	<u>423</u>
<u>Corner Brook Pulp and Paper Ltd.</u>			
Hydraulic	121.4	793	864
<u>AbitibiBowater Inc.</u>			
Hydraulic	58.5	430	467
<u>Non-Utility Generators</u>			
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	<u>66.3</u>	<u>317</u>	<u>394</u>
Total Island Interconnected System	<u>1,907.3</u>	<u>8,821</u>	<u>9,626</u>

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 than 2.8 hours per year⁵.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability⁶.

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.

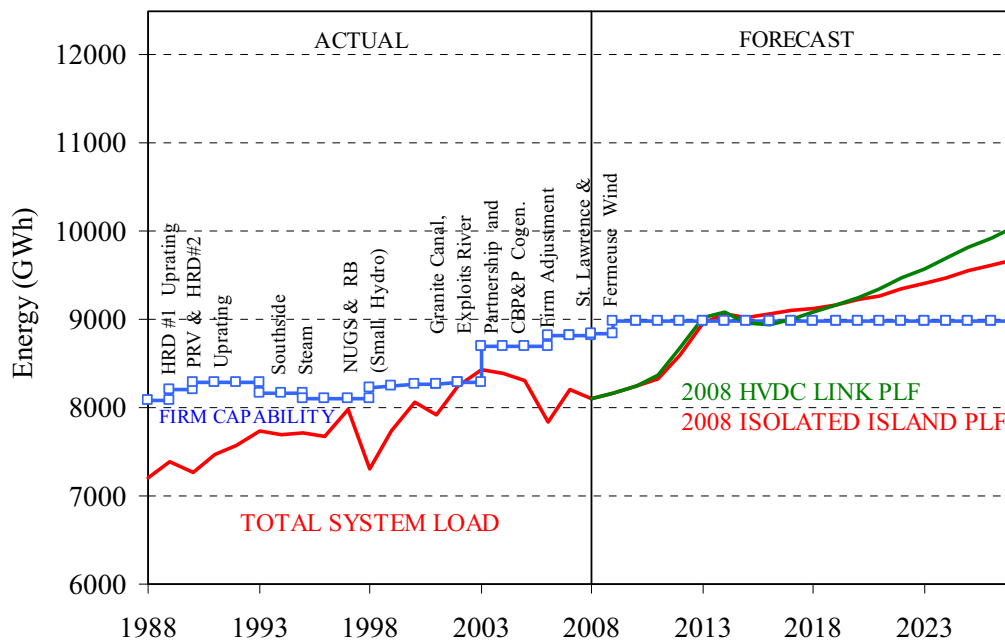
It should be noted that the capacity deficits trigger the need for the next generation source by 2013 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section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

Table 5-1 – Load Forecasts Compared to Planning Criteria

Year	Load Forecasts				Existing System plus 54 MW Wind Power in 2008		LOLH [hr/yr]		Energy Balance [GWh]	
	Maximum Demand [MW]		Firm Energy [GWh]		Installed Net Capacity [MW]	Firm Capacity [GWh]	HVDC Link	Isolated Island	HVDC Link	Isolated Island
	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 in 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, 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

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-cost⁷ 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

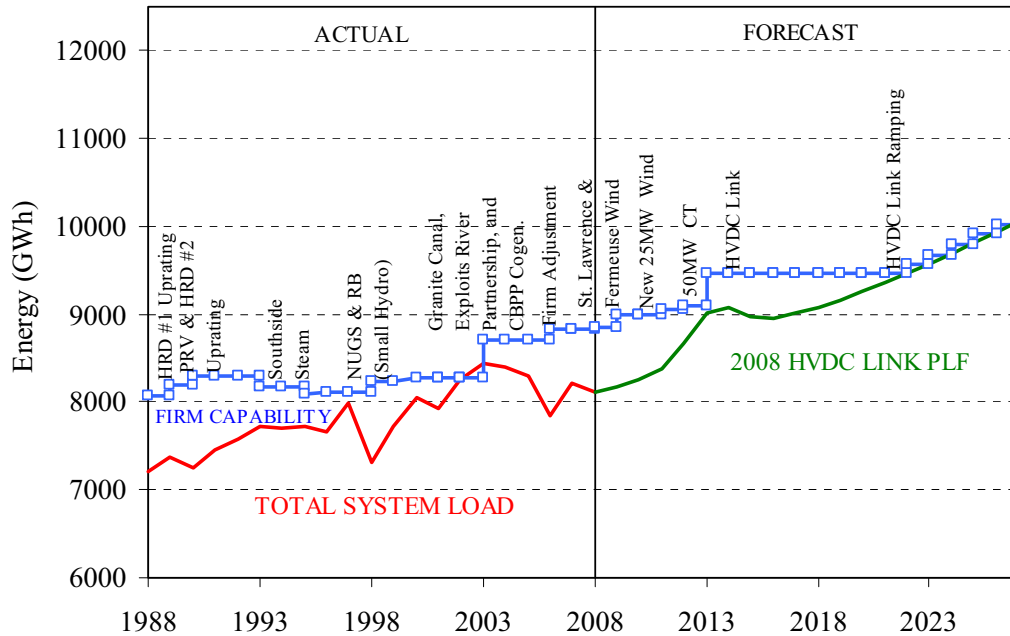
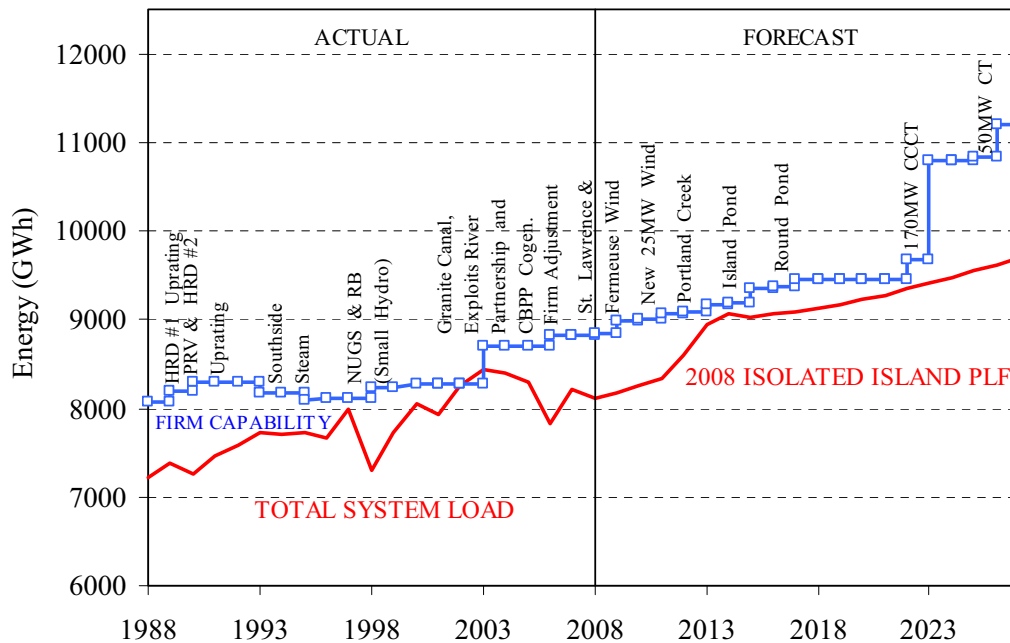


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



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 (SO₂) 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 SO₂ emissions by some 50 percent.

SO₂ 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 (CO₂) 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 year⁹. 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 CO₂, 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 CO₂ 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 until its end-of-life life 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)	Diesel (5.825 MBTU/BBL)
	[\$/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	████	████	████	████		████
Round Pond	████	████	████			████
Portland Creek	████	████	████			████
Hardwoods 50 MW CT	██	████	████			████
Stephenville 50 MW CT	██	████	████			████
Greenfield-1 50 MW CT	██	████	████			████
Greenfield-2 50 MW CT	██	████	████			████
Holyrood 125 MW CCCT	████	████	████			████
Holyrood 175 MW CCCT	████	████	████			████
Greenfield 175 MW CCCT	████	████	████	████		████
HTGS Unit IV	████	████	████	████		████
Wind 27 MW	████	████				████

* Excludes Escalation and Interest During Construction