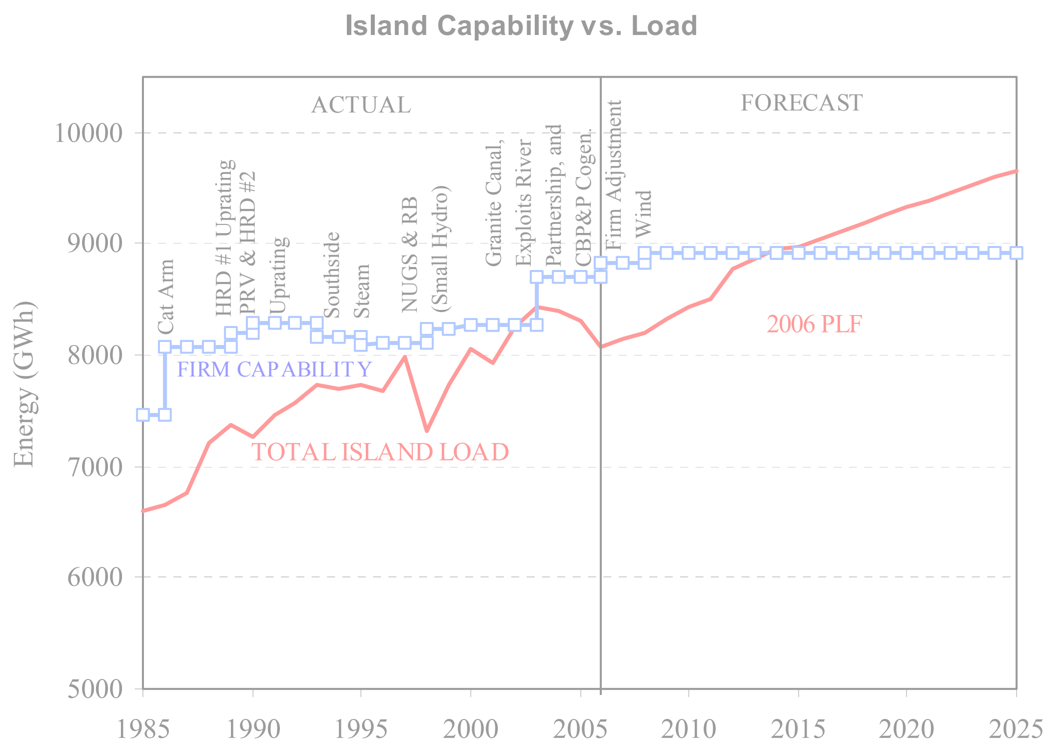
Schedule JRH-Supplementary 1 (Updated)

Generation Planning Issues

2006 Update



System Planning

December 2006

Executive Summary

This report provides an overview of the Island's 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.

Based on an examination of the Island's existing plus committed capability, in light of the 2006 Planning Load Forecast and the generation planning criteria, the Island system can expect capacity deficits starting in 2012 and minor firm capability deficits starting in 2014 and increasing thereafter.

In October 2006, due to the economic and environmental benefits associated with displacing heavy fuel oil at Holyrood, Hydro awarded an RFP for the development of a wind generation project, with planned in-service in 2008, and announced an RFP for a second wind project. Assuming a successful second project is selected for development, an RFP for a third wind project would be required by at least 2009 in order to meet a 2012 requirement for new supply resources based on Hydro's generation reliability criteria. Beyond that, another RFP is required in late 2009 to meet capacity and firm capability requirements in 2014.

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

- Environment/Emissions Control Considerations - Hydro must remain vigilant in considering the impact that environmental initiatives could have on production costing and future planning studies;
- Wind Power - Hydro will continue to pursue and develop wind projects while technically and economically feasible. Hydro assumes at present that the experience gained with the

integration of wind energy into the Island system will be positive and that this energy source will be developed to its acceptable limits;

- Resource Inventory - Hydro must ensure that it maintains an inventory of resource options with sufficient study as to provide confidence in overall project concept and costs;

- Labrador generation/Infeed - Hydro should consider an interconnection between the Island and Labrador as a future resource option on the Island due to ongoing progress in project planning.

Table of Contents

1. Introduction

The purpose of this report is to provide an overview of the Island's generation requirements in light of the most recent load forecast and the System's existing and committed capability. It addresses the timing of the next requirement for additional generation supply, 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. Load Forecast

This review utilizes the 2006 Planning Load Forecast (PLF) as prepared in the fall of 2005 by the Economic Analysis section of the System Planning department. The long-term load forecast for the Province is derived using Hydro's own electricity models and it is driven by a corresponding Provincial economic forecast that is regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. In Hydro's 2006 base case, some key assumptions respecting incremental economic activity are:

- Permanent closure of the Stephenville newsprint mill;
- Start-up of the Voisey's bay Nickel hydromet process facility on the Island in 2012;
- Indefinite delay of the Hebron development;
- Start-up of the Aur Resources' mine;
- Continued moratoria on most cod fisheries.

In terms of high-level economic indicators, their growth rate summaries are as follows:

Table 2-1

Provincial Economic Indicators, 2006 PLF			
	2005-2010	2005-2015	2005-2025
Adjusted Real GDP at Market Prices* (% Per Year)	0.9%	0.7%	0.8%
Real Disposable Income (% Per Year)	0.4%	0.6%	0.8%
Average Housing Starts (Number Per Year)**	2,169	2,034	1,806
End of Period Population (‘000s)	508.8	500.7	482.7
*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. **For housing starts the base year is 2006			

The focus of the load forecast analysis, and system planning generally, is naturally on the Island Interconnected System. Hydro has not yet incorporated the Lower Churchill generation and transmission investments into its base case economic and electricity projections. These developments are not yet technically committed through project sanction. Planning for the reliable operation and performance of the Island grid must proceed independent of Labrador resources until such time as such projects have firm commitments. Hydro normally handles large-scale projects, such as the Lower Churchill and Hebron developments, through alternative forecasts to the base case.

Hydro carries out system planning for the total Island Interconnected System and that includes the demand and energy supplied by Hydro’s customers’ own generation resources in addition to Hydro’s bulk and retail electricity supply. The projected electricity growth rates for the Island grid from the 2006 PLF are presented 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, following the loss of the newsprint mill load at Stephenville in late 2005, Aur Resources is expected to operate from 2007 to 2014, the VBN nickel processing facility is commissioned by 2012, and normal operations are assumed for the remaining newsprint mills and oil refinery.

Table 2-2

Interconnected Island Electricity Load Growth Summary, 2006 PLF

	2005-2010	2005-2015	2005-2025
Utility[1]	1.1%	0.9%	1.0%
Industrial[2]	(3.1%)	(0.3%)	(0.1%)
Total	(0.2%)	0.5%	0.6%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. In total, industrial customer load growth is negative due to the loss of the large AC Stephenville newsprint mill load in late 2005. Industrial load is the summation of Corner Brook Pulp and Paper, Abitibi Consolidated Grand Falls, North Atlantic Refining, Aur Resources and Voisey's Bay Nickel.

Table 2-3 provides a summary of the 2006 PLF projections for electric power and energy for the Island Interconnected System for the eleven-year period 2006 to 2016. Similar long-term projections are also prepared for the Labrador Interconnected System and for Hydro's Isolated Diesel System to derive a Provincial electricity load forecast.

Table 2-3

Interconnected Island Electricity Load Summary, 2006 PLF						
	Utility[1]		Industrial[1]		Total Island[2]	
	MW	GWh	MW	GWh	MW	GWh
2006	1,281	5,688	309	2,226	1,563	8,079
2007	1,289	5,733	307	2,250	1,569	8,150
2008	1,303	5,793	307	2,234	1,583	8,196
2009	1,315	5,900	307	2,251	1,595	8,322
2010	1,334	6,003	307	2,251	1,615	8,426
2011	1,355	6,077	307	2,251	1,635	8,501
2012	1,357	6,078	354	2,521	1,684	8,775
2013	1,371	6,114	354	2,566	1,698	8,857
2014	1,378	6,172	354	2,606	1,705	8,956
2015	1,390	6,234	347	2,556	1,710	8,969
2016	1,402	6,305	347	2,556	1,722	9,040

Note: 1. Utility and Industrial MW are non-coincident peak demands.
2. Total Island includes losses and MW are coincident peak demand.

3. System Capability

Table 3-1 provides a summary of the existing capacity and energy capability of the Island System. Hydro is the prime supplier of electrical energy, accounting for 80% of the Island's net capacity. The remaining capacity is supplied by Newfoundland Power Inc. (8%), Corner Brook Pulp and Paper Limited (6%) and Abitibi Consolidated Inc. (3%). Hydro also has contracts with four Non-Utility Generators (3%) for the supply of energy.

Hydroelectric generating units account for 65% of the total existing Island net capacity and firm energy capability. The remaining net capacity comes from thermal resources on the

Island and is made up of conventional steam, combustion turbine and diesel generating plants. Approximately 70% of the existing thermal capacity is located at the Holyrood Thermal Plant and is fired using No. 6 fuel oil. The remaining capacity is located at sites throughout the Island.

Table 3-1

Island Capability	Net Capacity (MW)	Energy (GWh)	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay D'Espoir	592.0	2264	2605
Upper Salmon	84.0	486	551
Hinds Lake	75.0	281	341
Cat Arm	127.0	678	706
Granite Canal	40.0	220	225
Paradise River	8.0	27	37
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
TOTAL HYDRO	927.3	3961	4472
Holyrood	465.5	2996	2996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
TOTAL THERMAL	598.2	2996	2996
Newfoundland Power Inc.			
Hydro	92.1	324	423
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
TOTAL	135.6	324	423
Corner Brook Pulp and Paper Ltd.			
Hydro	121.4	793	864
Abitibi Consolidated Inc.			
Hydro	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 EXISTING (June 2006)	**1907.3**	**8821**	**9616**

4. Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the total Island 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 load, 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.

Energy

The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm System capability[1].

5. Identification of Need

Table 5-1 presents an examination of the base case load forecast (Table A1) with the planning criteria. It does not incorporate Hydro's preliminary expansion plan to show future uncommitted generation additions but it does incorporate the awarding of a 25 MW wind project scheduled in-service in 2008. In 2006, the system firm capability was adjusted to reflect a 115 GWh increase in Hydro's hydraulic plants' capability. This change is the result of adjusted hydrology and the use of a new integrated system model which is able to determine a system

[1] Firm System capability for the hydroelectric system is the energy capability of the system under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm energy for the thermal resources (Holyrood) is based on energy capability adjusted for maintenance and forced outages.

firm capability. Previous values were the results of the sum of individual firm values provided by the design consultants of each facility.

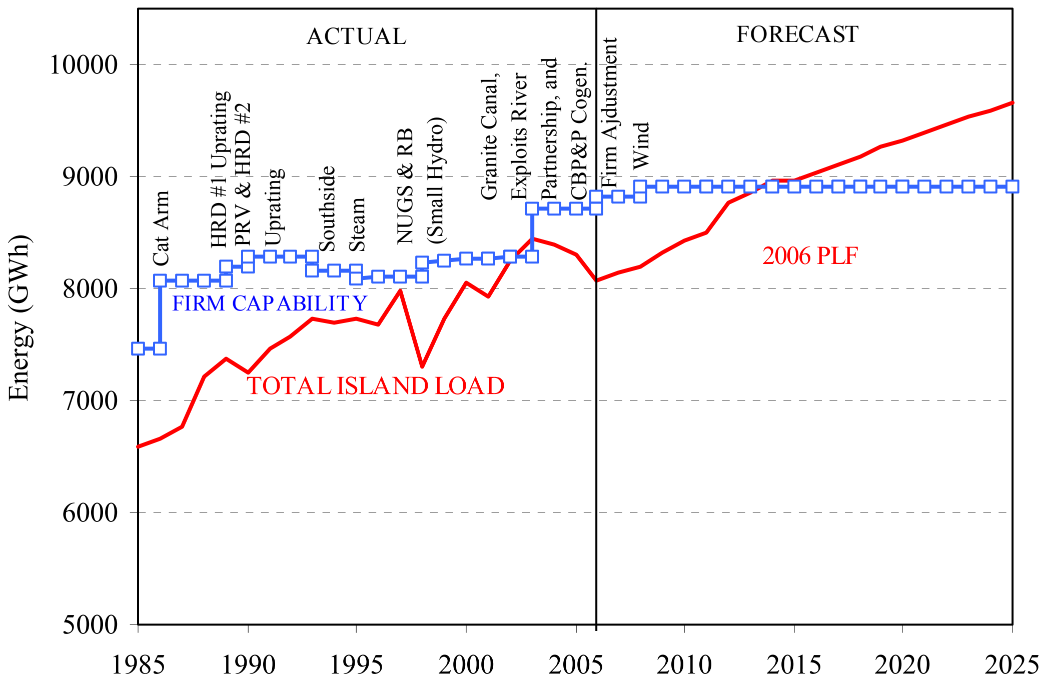
The table illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand. The table shows capacity deficits starting in 2012 and minor energy deficits starting in 2014. Since the closure of the ACI mill in Stephenville, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained. It should be noted that the energy deficits in 2014 and 2015 are considered minor due to the risk associated with demand forecasts coupled with the large difference between firm and average production capability from hydroelectric resources. Therefore, the need for new generation could possibly be delayed until as late as 2016. As time moves on and annual updates to this report are prepared, the timing of future generation will become clear. For purposes of this report it is assumed that additional generation will be required in 2014.

Table 5-1

Near Term Capability Requirements						
	Base Case Load Forecast		Existing System plus 25 MW Wind Power in 2008		Existing System plus 25 MW Wind Power in 2008	
Year	Peak MW	Firm Energy GWh	Installed Net Capacity MW	Firm Capability GWh	LOLH hrs/yr	Energy Balance (GWh)
2006	1,563	8,079	1,907	8,821	0.52	742
2007	1,569	8,150	1,907	8,821	0.60	671
2008	1,583	8,196	1,932	8,836	0.71	641
2009	1,595	8,322	1,932	8,912	0.76	590
2010	1,615	8,426	1,932	8,912	1.09	486
2011	1,635	8,501	1,932	8,912	1.52	411
2012	1,684	8,775	1,932	8,912	**3.49**	137
2013	1,698	8,857	1,932	8,912	4.51	55
2014	1,705	8,956	1,932	8,912	5.39	**(44)**
2015	1,710	8,969	1,932	8,912	5.73	(57)
2016	1,722	9,040	1,932	8,912	6.75	(128)

Figure 5-1 presents a graphical representation of historical and projected load and system capability for the base case scenario.

Figure 5-1 - Island Capability vs. Load



6. Near Term Resource Options

This section presents a summary of options currently identified for near term generation expansion. Included is a brief project description as well as discussion surrounding project schedules, the current status of capital cost estimates and any other issues related to generation expansion analysis and bringing an alternative into service.

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 the available head between the existing Meelpaeg Reservoir and the Upper Salmon Development to produce firm and average annual energy capability of 186 GWh and 203 GWh, respectively.

The development would include the construction of a 3 km long diversion canal between Meelpaeg Reservoir and Island Pond, which would raise Island Pond to the Meelpaeg Reservoir level. As well, approximately 3.4 km of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 m long forebay would pass water to the dam, intake and powerhouse and discharge it into Crooked Lake via a 550 m long tailrace.

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

Schedule and Cost Estimate

The project had undergone a full environmental review in the late 80's and early 90's. Component studies and an Environmental Impact Statement were submitted in 1993, which was accepted by the Minister but could not go to Cabinet for final approval since the four-year preparation period was exceeded. It was registered again in 1997 at which time an Environmental Preview Report (EPR) was required. The project will have to be registered yet again prior to project release. In the absence of any further work beyond that identified in 1997, the overall schedule is estimated to be approximately 43 months from start to finish. If further field work is identified, the schedule may have to be extended.

The current capital cost estimate for Island Pond is based on the "Re-Optimization and Cost Update Study" which was prepared in 1997. To ensure that Hydro is in a position to properly evaluate Island Pond, along with other competitive alternatives that may be submitted in a future RFP (see Section 8), Hydro has commissioned an outside consultant to prepare a "final feasibility" level study and estimate, to be completed in December 2006.

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 head between the existing Long Pond Reservoir and Godaleich Pond to produce firm and average annual energy capability of 128 GWh and 132 GWh, respectively.

Schedule and Cost Estimate

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study prepared for Hydro by outside consultants entitled "Round Pond Hydroelectric Development" and the associated 1989 Summary Report based on the same. In the absence of any further work beyond that 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.

Portland Creek

Portland Creek is a proposed 12 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Great Northern Peninsula. The project would produce firm and average annual energy capability of 77 GWh and 91 GWh, respectively.

Schedule and Cost Estimate

The current schedule and capital cost estimate for Portland Creek is based on the 1987 prefeasibility study prepared for Hydro by outside consultants entitled "Small Hydro Studies". 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. It may be necessary to start the preparation of tender documents before the project release date to ensure that work on the access road and the transmission line can begin on time.

To ensure that Hydro is in a position to properly evaluate Portland Creek, along with other competitive alternatives that may be submitted in a future RFP (see Section 8), Hydro has commissioned an outside consultant to prepare a "feasibility" level study and estimate, to be completed in December 2006.

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 inherent to the Island System 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 Island System. In October 2006, Hydro awarded its first 25 MW wind project and called an RFP for a second 25 MW wind project, the results of which are due in late 2006.

As an example, each 25 MW wind farm could consist of a collection of 8 to14 individual 3,000 kW to 1,800 kW wind turbines interconnected to a single delivery point on the Island System's transmission network. Firm and average annual energy capability from such a project is estimated to be in the range of 80 and 110 GWh depending on the site location. While Hydro would not develop wind production projects strictly for capacity deficits, these projects do carry some capacity value and therefore influence the LOLH calculations.

Schedule and Cost Estimate

Wind projects typically require at least 12 months of site specific environmental monitoring to adequately define the resource. Project development and feasibility studies for attractive sites are typically carried out concurrent with the resource study and are often completed following the year long resource assessment. The final design and construction for a 25 MW wind farm could be completed over an additional 12 to 18 months. The overall project schedule calls for approximately 30 months from start to finish. Additional time may be required, depending on market conditions, to secure turbine delivery. Presently, Hydro's first interconnected wind project is expected to be in-service by December 2008.

First year cost for wind energy is estimated to be 6 to 7 cents/kWh for projects completed in the near term. This cost does not include allowance for Government incentives such as the Wind Power Production Incentive (1.0 cents/kWh for the first 10 years of production), nor does it include value allowances for any environmental attributes.

Holyrood Combined Cycle Plant

Two alternatives have been identified and estimates prepared for a proposed Holyrood Combined Cycle Plant; a 125 MW and a 170 MW (net) combined cycle combustion turbine facility.

The combined cycle unit consists of a combustion turbine fired on light oil, a heat recovery steam generator, and a steam turbine generator. The plant would be located at the existing Holyrood Thermal Plant site to take advantage of the operational and capital cost savings associated with sharing existing facilities. The annual firm energy capability is estimated at 986 GWh for the 125 MW unit and 1,340 GWh for the 170 MW unit.

Schedule and Cost Estimate

It is expected that the Holyrood Combined Cycle Plant would require 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 36 months from start to finish.

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

Holyrood Unit IV

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

Schedule and Cost Estimate

It is expected that the Holyrood Unit IV project would require 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 start to finish.

In a March 2000 update of the capital cost estimate for the Holyrood Unit IV project the following concerns were raised surrounding the accuracy of the estimate:

- The basis for the estimate is eleven years old and does not reflect current market conditions;
- There are indications that manufacturers of conventional thermal plant equipment have reduced their prices to remain competitive with combined cycle power plants; and
- Some of the items included in the original capital cost estimate as general plant improvements have been implemented in the interim and should be removed from the cost estimate.

Recent sensitivity analysis has demonstrated that the capital cost of the proposed Holyrood Unit IV project would have to drop by approximately 20% to be competitive with the combined cycle option. It is the opinion of Hydro's Engineering Services division that such a magnitude of decrease in cost is highly unlikely. Further, given the anticipated stricter environmental regulations, the capital cost for the project could likely rise. Therefore, while Hydro will continue to include the proposed Holyrood Unit IV project in its portfolio of alternatives, at such time that appropriate sensitivity analysis identifies the project as a potential near term addition, the project feasibility and cost estimate should be reviewed in detail.

Hardwoods Unit 2 and Stephenville Unit 2 Combustion Turbine Units

These nominal 50 MW simple cycle combustion turbines would be located adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations. They are fired on light oil and are designed for peaking and voltage support functions.

Schedule and Cost Estimate

It is anticipated that both of these options will require an EPR. The overall project schedule is estimated to be approximately 32 months from start to finish.

The capital cost estimate for these units was reviewed and updated in October 2000. Approximately 90% of the direct cost is for the gas turbine package and, with the sustained demand for gas turbines, prices can be expected to remain volatile for several years. Hydro should continue to monitor turbine prices to determine when further review of the capital cost estimates becomes necessary.

7. Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast period to 2025, Hydro uses NewEnergy Strategist software to plan generation for the Island Interconnected System for any 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 analysis presented is considered preliminary as it has not been submitted for Board approval and it represents Hydro's preferred path on how it would proceed given no change from the base case assumptions. For this analysis, wind generation projects and other projects in Hydro's own portfolio of resource options are made available to meet future load requirements.

In October 2006, Hydro awarded a 25 MW wind project after a successful RFP process. Contracting for this additional supply in advance of identified incremental system requirements is due to the economic and environmental benefits associated with displacing heavy fuel oil at Holyrood. It is expected that a Power Purchase Agreement will be signed in late 2006, and the project will be in-service by December 2008. A second RFP for an additional 25 MW wind project was also issued at that time, again for potential economic and known environmental benefits, rather than identified System requirements. The decision to award the second RFP is due in late 2006. At current load growth forecast rates, a third 25 MW wind project would be required to be in-service as late as 2012.

The generation expansion analysis uses an 8.4% discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2005. 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[2] generation expansion plan under the base case is shown below in Table 7-1 and graphically in Figure 7-1. Generation from wind continues as the preferred next source from amongst Hydro's identified portfolio of resource options. From there the next least cost supply options, in increasing order of cost, are the indigenous hydroelectric plants of Island Pond, Round Pond and Portland Creek. In order to complete the generation expansion analysis, Hydro has opted to include in 2020 a 125MW CCCT plant as indicative of the most economic thermal plant, which the Island would require in the long term as an isolated grid.

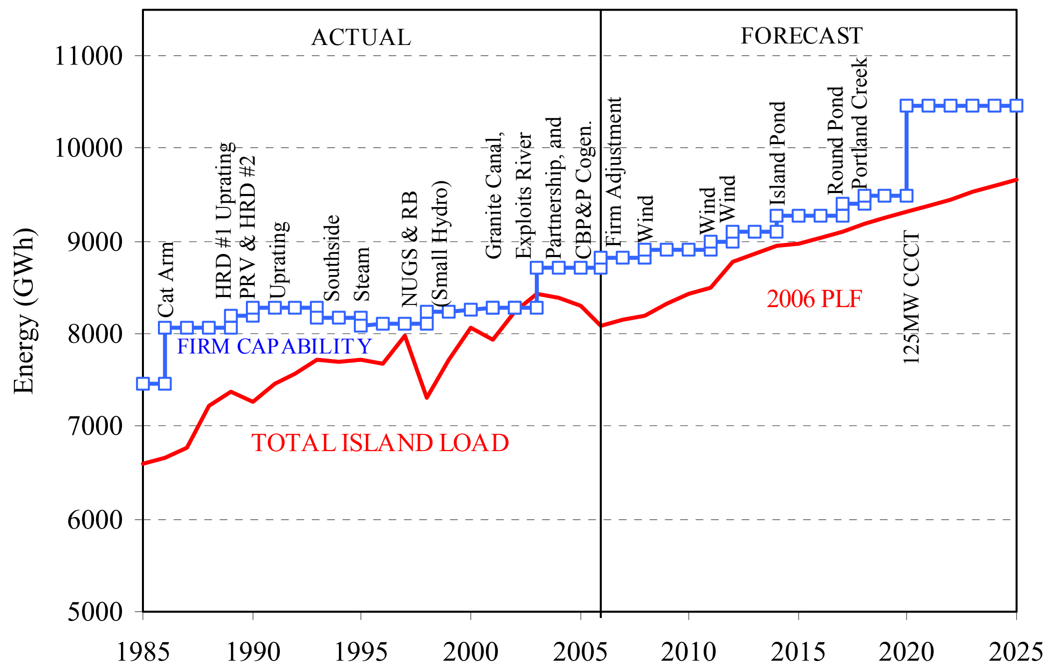
While the expansion plan is indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future and following a full review of Provincial resources, which likely would include a Request for Proposals. These, and other related issues, are discussed further in the following section.

[2] For Hydro, the term "least cost" refers to the lowest Cumulative Present Worth/Value (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.

Table 7-1

Year	2006 Base Case Generation Expansion Plan (Preliminary)
	Hydro's Alternatives + Wind (Capacity/Firm Capability)
2006	
2007	
2008	Wind (25 MW/91 GWh)
2009	
2010	
2011	Wind (25 MW/91 GWh)
2012	Wind (25 MW/91 GWh)
2013	
2014	Island Pond (36MW/186 GWh)
2015	
2016	
2017	Round Pond (18 MW/128 GWh)
2018	Portland Creek (12 MW/77 GWh)
2019	
2020	CCCT (125 MW/986 GWh)
2021	
2022	
2023	
2024	
2025	
Note: This expansion plan satisfies Hydro's generation planning criteria well beyond the 2025 planning horizon.	

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



8. Timing of Next Decision

8.1. Request for Proposals

In addition to those resources included in Hydro's own portfolio alternatives, any number of alternatives may be brought forward under a general request for generation proposals (RFP). As with the 1997 RFP, alternatives submitted under a general RFP can range from various forms of conventional hydro and thermal resources 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 7 months. This was accomplished only through having a high priority placed on the process by Management, the commitment of key personnel from various departments and the assistance of consultants from outside Hydro. Due to the urgency to have a final report on generation expansion alternatives ready by mid-June 1997, the RFP that was issued in mid-January, gave proponents only approximately 3 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 would likely 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.

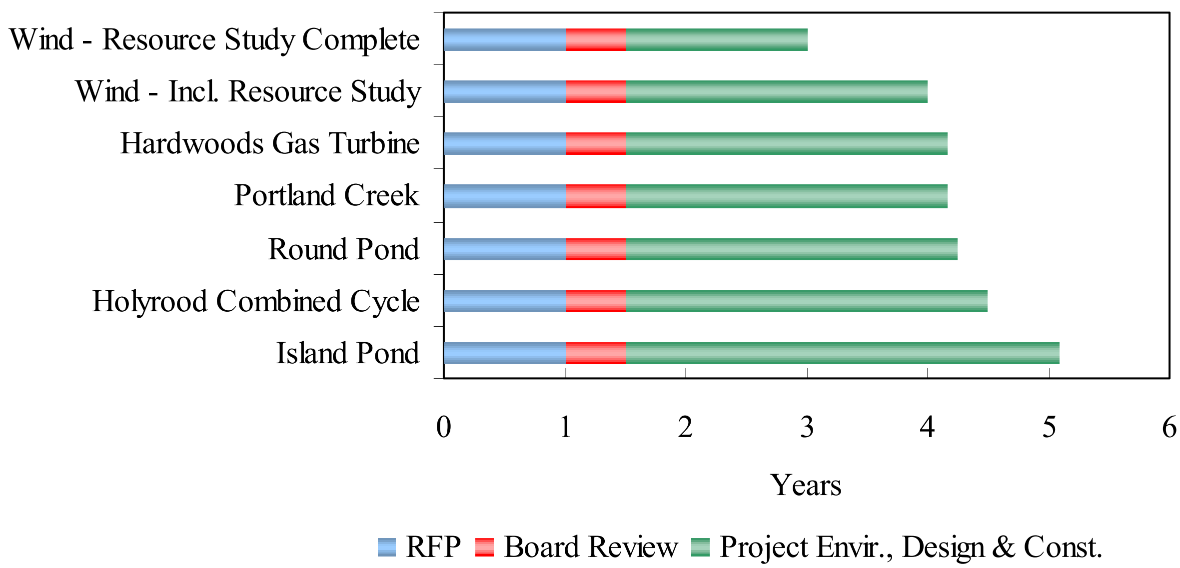
8.2. Public Utilities Board

Prior to 1996, Hydro was not required to seek approval from the Board of Commissioners of Public Utilities (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, whether owned or contracted. This regulatory process has yet to be initialized and is estimated to take up to 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, there could be significant interest in a hearing for a new generation source.

8.3. Decision Timing

The bar chart shown in Figure 8-1 illustrates the lead times, including that required for a Board review, for each of Hydro's near term alternatives.

Figure 8-1 - Project Lead Times



There is a new forecast and generation expansion plan each year to keep abreast of changes to electricity demand and supply conditions. Under the 2006 base case forecast scenario that assumes a 25 MW wind project in 2008, the next requirement for additional generation is in 2012 due to capacity shortfalls. Assuming two additional 25 MW wind projects in the 2008 to 2012 time period, the next generation project will be required in 2014, as noted in Table 7-1. The energy deficit noted in Table 5-1 starting in 2014 is less than 0.5% of firm capability and is considered minor given the risk associated with demand forecasts coupled with the large difference between firm and average production capability from hydroelectric resources. Therefore, barring no significant change in the demand forecast or other variables, future analysis and annual updates to this report could see the need for additional generation pushed to as late as 2016. For the purposes of this report it is assumed that the generation will be required in 2014.

Provided that the current RFP for 25 MW of wind generation is successful, Hydro would have to initiate the RFP process for the third 25 MW project as late as 2009 to meet the required in-service date of 2012.

Hydro would also have to initiate another RFP process in late 2009 to meet the in-service date for the next required generation in 2014. This is due to the need to complete the RFP evaluation and subsequent Board review to allow sufficient time to protect the in-service date if the decision is to proceed with the Island Pond alternative.

9. 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/year limitation on SO_2 emissions from Holyrood, have traditionally been included in generation planning studies.

In January 2006, Hydro announced that it would source 1% sulphur No. 6 fuel oil for its Holyrood generating facility. While there are additional purchase costs for 1% sulphur over 2% sulphur fuel oil, this improvement in fuel grade will reduce sulphur-dioxide (SO_2) emissions by some 50%[3].

SO_2 is the one of the necessary compounds to form acid rain. Exposure can also have negative health effects on people, especially those with respiratory illness. Hydro has also participated in studies to evaluate and communicate to Government the potential

[3] The first shipment of 1% sulphur fuel oil was received in March 2006. Due to the 2% sulphur fuel oil that was in storage at that time, Hydro began blending 2% with 1%. In 2007 the emission reduction target with burning 1% sulphur fuel should be realized.

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 Kyoto, Clean Air Act, 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. Hydro should maintain a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of a resource decision.

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 1.5 million tonnes per year[4]. 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.

9.2. Labrador Infeed

Hydro has not yet incorporated the Lower Churchill generation and transmission investments into its base case economic and electricity projections. These developments are not yet technically committed through project sanction and planning. Therefore, the reliable operation and performance of the Island grid must proceed independent of Labrador resources until such time as such projects have firm commitments. Notwithstanding, Hydro's progress on moving forward with the necessary planning for the development of the Lower Churchill means that this resource option should be

[4] Based on the 5-year average from the 2001 to 2005 period.

considered in Hydro's portfolio of generation alternatives for the 2007 update of this report.

10. Summary

Based on an examination of the Island's existing plus committed capability, in light of the 2006 Planning Load Forecast and the generation planning criteria, the Island system can expect capacity deficits starting in 2012 and energy deficits in 2014. The addition of wind projects in the interim could delay these deficits and the need for additional generation even further. For example, building two additional 25 MW wind projects in the 2008 – 2012 time frame could delay the requirement for new generation to at least 2014. Firm energy deficits beginning in 2014 are considered minor due to the risk associated with demand forecasts coupled with the large difference between firm and average production capability from hydroelectric resources. Therefore, the need for new generation could possibly be delayed until as late as 2016. For the purposes of this report it is assumed that three wind projects will be in-service by 2008, 2011 and 2012 and the next generation source will be required in 2014. As time moves on and annual updates to this report are prepared, the timing of future generation will become clear.

Currently, a RFP is outstanding on a second wind project for economic and environmental benefits of displaced heavy fuel oil at Holyrood. In addition to these benefits, wind projects also influence the LOLH and hence carry some capacity value. Assuming a successful project is selected, an RFP for a third wind project would be required by at least 2009 in order to meet a 2012 requirement for new supply resources based on Hydro's generation reliability criteria. Beyond that, another RFP is required in late 2009 to meet capacity and firm capability requirements in 2014.

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

- Environment/Emissions Control Considerations - Hydro must remain vigilant in considering the impact that environmental initiatives could have on production costing and future planning studies;

- Wind Power - Hydro will continue to pursue and develop wind projects while technically and economically feasible. Hydro assumes at present that the experience gained with the integration of wind energy into the Island system will be positive and that this energy source will be developed to its acceptable limits;

- Resource Inventory - Hydro must ensure that it maintains an inventory of resource options with sufficient study as to provide confidence in overall project concept and costs;

- Labrador generation/Infeed - Hydro should consider an interconnection between the Island and Labrador as a future resource option on the Island due to ongoing progress in project planning.

Appendix A

Table A-1
2006 Planning Load Forecast

	2006 PLF – Base Case	
	Demand	Energy
Year	MW	GWh
2006	1,563	8,079
2007	1,569	8,150
2008	1,583	8,196
2009	1,595	8,322
2010	1,615	8,426
2011	1,635	8,501
2012	1,684	8,775
2013	1,698	8,857
2014	1,705	8,956
2015	1,710	8,969
2016	1,722	9,040
2017	1,735	9,110
2018	1,747	9,186
2019	1,761	9,259
2020	1,773	9,326
2021	1,785	9,386
2022	1,798	9,458
2023	1,810	9,529
2024	1,823	9,597
2025	1,835	9,663

Appendix B

Table B-1
Fuel Forecast

Year	Residual 1.0%S (6.287 mBTU/BBL) $/BBL	Diesel (5.825 mBTU/BBL) $/litre
2006	45.00	0.520
2007	45.15	0.485
2008	47.45	0.478
2009	48.05	0.477
2010	48.35	0.477
2011	51.60	0.499
2012	54.40	0.521
2013	57.10	0.543
2014	59.80	0.565
2015	62.40	0.588
2016	63.70	0.600
2017	65.00	0.613
2018	66.35	0.625
2019	67.70	0.638
2020	69.10	0.651
2021	70.55	0.665
2022	72.00	0.679
2023	73.50	0.692
2024	75.00	0.707
2025	76.55	0.721

Source: NLH Economic Analysis Section, November 2005

Table B-2
Escalation Rates

Year	Hydraulic & Thermal Plant Construction	O&M	
		Materials ~ 75% Labour ~ 25%	Materials ~ 50% Labour ~ 50%
2006	1.8%	1.6%	1.7%
2007	2.0%	2.0%	2.1%
2008	1.9%	1.9%	2.1%
2009	1.9%	1.9%	2.2%
2010	1.9%	1.9%	2.1%
2011	2.0%	2.0%	2.3%
2012	1.9%	1.9%	2.2%
2013	1.9%	1.9%	2.2%
2014	1.9%	1.9%	2.2%
2015	2.0%	2.0%	2.2%
2015-2020	2.0%	2.0%	2.3%
2020-2025	2.1%	2.1%	2.4%

Source: NLH Economic Analysis Section, September 2005

Table B-3
Future Resource Capital Cost Flow Estimates

Project	Direct Costs in January 2005$ (x 1,000)**					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Island Pond	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Round Pond	[redacted]	[redacted]	[redacted]			[redacted]
Portland Creek	[redacted]	[redacted]	[redacted]			[redacted]
Hardwoods CT	[redacted]	[redacted]	[redacted]			[redacted]
Stephenville CT	[redacted]	[redacted]	[redacted]			[redacted]
125 MW Holyrood CCCT	[redacted]	[redacted]	[redacted]			[redacted]
170MW Holyrood CCCT	[redacted]	[redacted]	[redacted]			[redacted]

** Excludes Escalation and Interest During Construction