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Executive Summary

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

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

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

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

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

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

Table of Contents

1.0 Introduction

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

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

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

2.0 Load Forecast

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

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

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

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

Table 2-1

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

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

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

Table 2-2

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

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

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

Table 2-3

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

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

3.0 System Capability

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

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

Table 3-1

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

4.0 Planning Criteria

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

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

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

5.0 Identification of Need

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

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

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

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

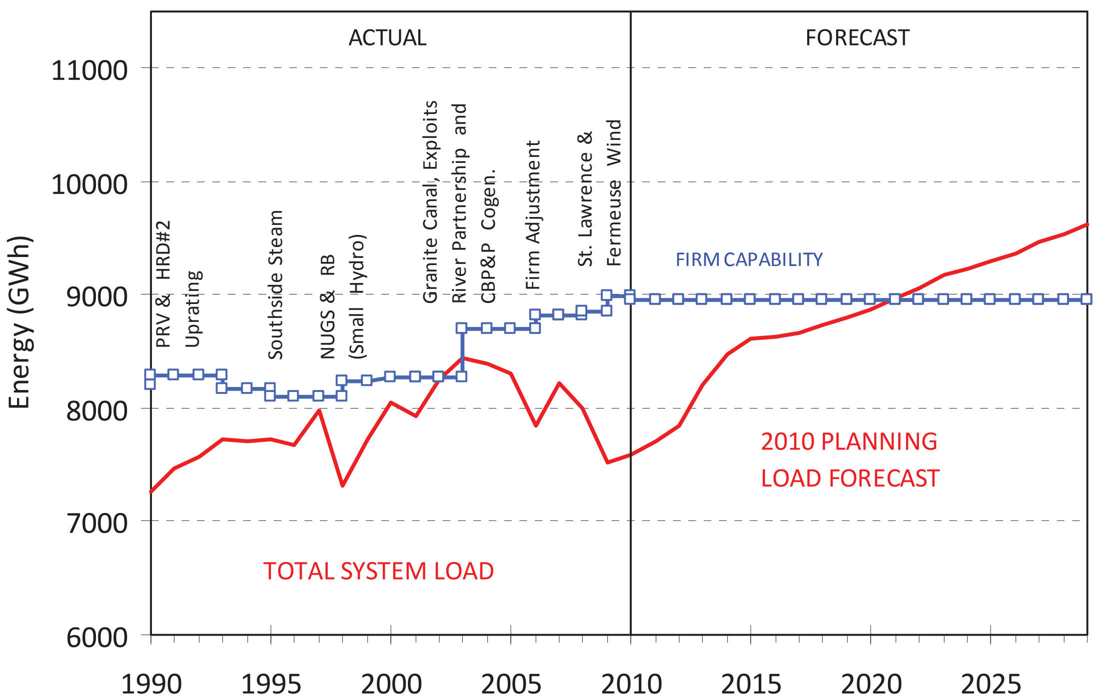
It should be noted that the capacity deficits trigger the need for the next generation source by 2015 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section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

Table 5-1 – Load Forecast Compared to Planning Criteria

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

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

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



6.0 Near-Term Resource Options

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

6.1 Island Pond

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

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

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

Schedule and Cost Estimate Basis

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

6.2 Portland Creek

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

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

Schedule and Cost Estimate Basis

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

6.3 Round Pond

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

Schedule and Cost Estimate Basis

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

6.4 Wind Generation Projects

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

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

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

Schedule and Cost Estimate Basis

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

6.5 Combined Cycle Plant

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

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

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

Schedule and Cost Estimate Basis

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

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

6.6 Holyrood Thermal Generating Station Unit IV

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

Schedule and Cost Estimate Basis

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

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

6.7 Combustion Turbine Units

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

Schedule and Cost Estimate Basis

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

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

6.8 High Voltage Direct Current (HVdc) Link

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

7.0 Preliminary Generation Expansion Analysis

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

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

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

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

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

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

7.1 High-Voltage Direct Current Link Scenario

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

7.2 Isolated Island Scenario

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

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

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

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

Table 7-1

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

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

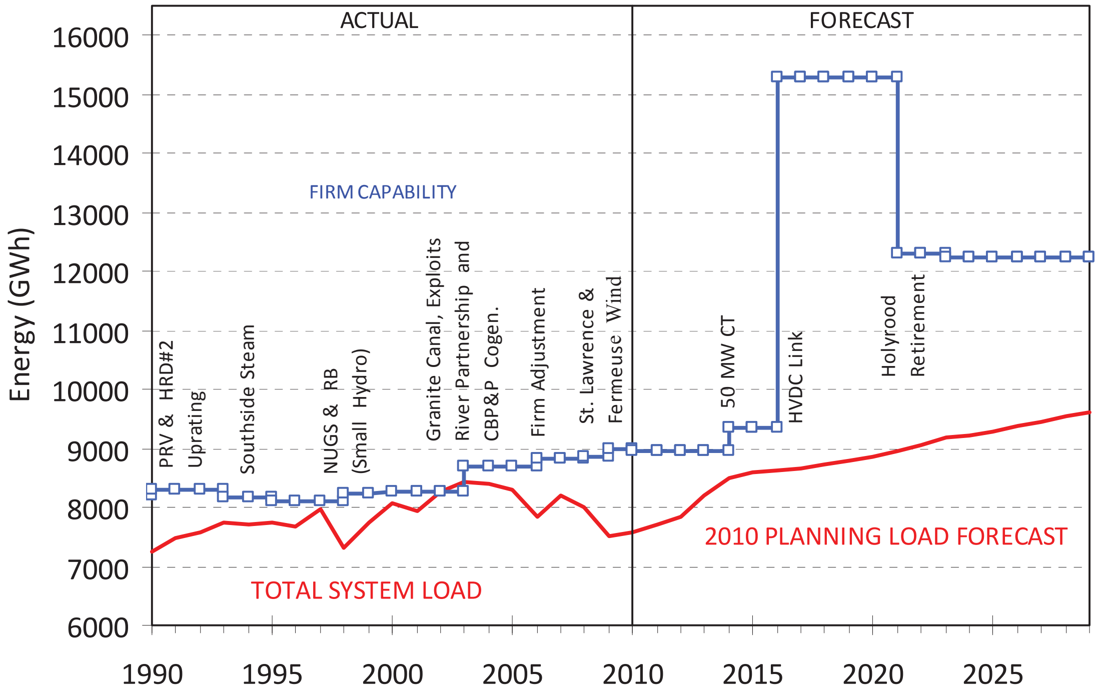
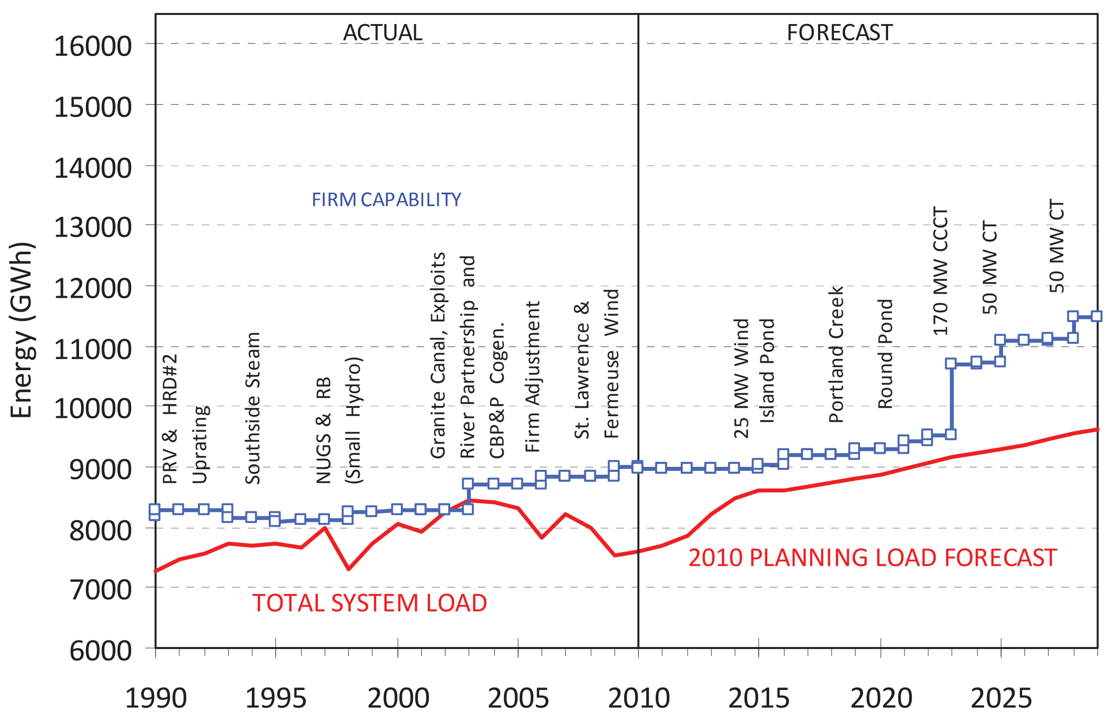


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 Request for Proposals

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

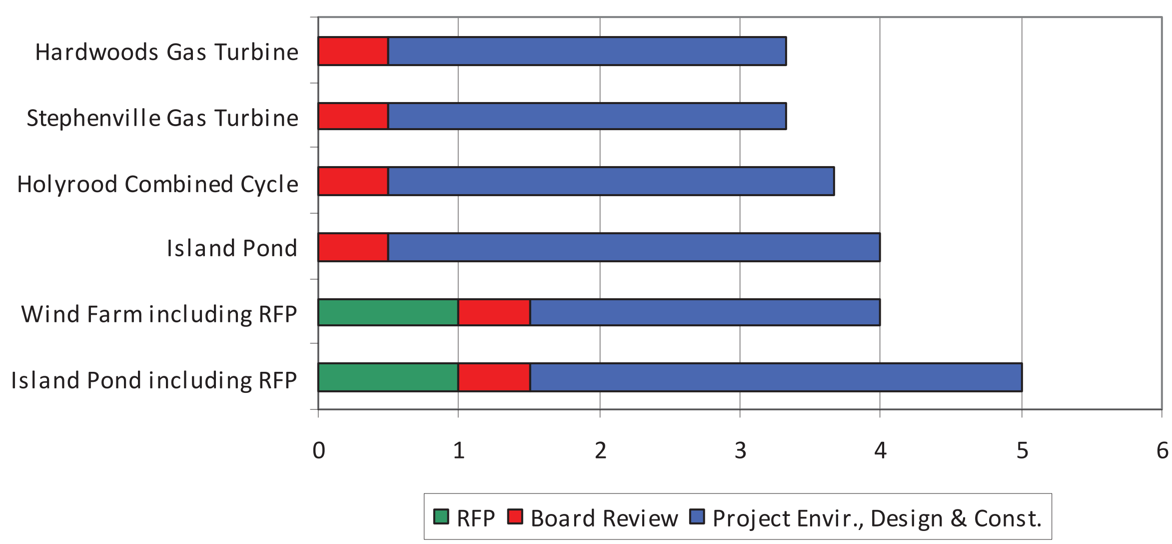
In addition to the time required to bring a project through the normal environmental and construction schedules, additional lead time is required to implement an RFP process. Based on Hydro's 1997 experience, the minimum amount of time required to issue and evaluate proposals through an RFP process is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

8.2 Newfoundland and Labrador Board of Commissioners of Public Utilities

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

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

Figure 8-1 - Project Lead Times



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

9.0 Other Issues

9.1 Intermittent and Non-Dispatchable Resources

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

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

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

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

9.2 Environmental Considerations

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

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

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

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

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

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

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

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

9.3 Holyrood Thermal Generating Station End-of-Life

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

9.4 Energy Conservation

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

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

10.0 Conclusion

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

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

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

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

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

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

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

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Appendix A

Table A-1
2010 Island Planning Load Forecast

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