Q. Further to the response to PUB-NLH-001, in which the short-term system capacity is provided, provide Hydro's most recent long-term forecast used for determining the timing of the next generation source which includes the current system capacity used for long-term planning purposes. In the response provide a copy of Hydro's most recent Generation Planning Issues report.

A. Hydro's most recent official long-term forecast used for determining the timing of the next generation source, which includes the current system capacity used for long-term planning purposes, is shown in Table 1. The load forecast is also contained in Table A – 1 of Appendix A, of the attached copy of Hydro's most recent Generation Planning Issues report, *Generation Planning Issues November 2012*.

A "seed"[1] forecast was produced in June 2013 (please see Table 2). A comparison of this forecast to the 2012 forecast determined that the change in customer requirements would not affect the required future generation prior to the in-service of Muskrat Falls and the Labrador-Island Link and therefore an updated official forecast and Generation Planning Issues report were not issued.

[1] A "seed" forecast is the initial forecast used in the long-term generation planning process. It is not an official forecast because it is subject to change as the planning process evolves.

Table 1

Island Interconnected System
Load Forecast and Capacity and Energy Balances
With Proposed Additions

	Load Forecast	Existing and Proposed System	
	Peak	Planning Capacity[1]	LOLH
Year	MW	MW	hrs/yr
2013	1,632	1,855	0.97
2014	1,691	1,855[2]	2.59
2015	1,721	1,915[3]	3.91
2016	1,736	1,915	2.34
2017	1,755	1,915	3.01

[1] Planning Capacity – Assumed net capacity available at time of peak demand.
[2] In Hydro's response to PUB-NLH-001, gross numbers were used for Holyrood, to correspond with the numbers Hydro used in its Available Island Generating Capacity charts.
[3] 60 MW CT in-service December 2015.

Table 2

2012 Official Load Forecast		2013 "Seed" Forecast	
	Peak		Peak
Year	MW	Year	MW
2013	1,632	2013	1,570
2014	1,691	2014	1,652
2015	1,721	2015	1,708
2016	1,736	2016	1,727
2017	1,755	2017	1,744

GENERATION PLANNING ISSUES
NOVEMBER 2012

System Planning Department
November 2012

newfoundland labrador
hydro
a nalcor energy company

Executive Summary

This report provides an overview of the Island Interconnected System (System) generation capability for the next 20 years, the proposed timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies issues that need to be considered to ensure a decision on the preferred source can be made through an orderly and cost-effective process.

The long-term plan proposed in the Energy Plan is to replace the energy provided by the Holyrood Thermal Generating Station (HTGS) with electricity from the Lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island, known as the Labrador – Island Transmission Link (LIL). Currently, the generation source to be developed in Labrador is Muskrat Falls. In the event the Muskrat Falls Project (Muskrat Falls and the LIL) does not proceed, a supply future utilizing small hydro, wind and continued thermal based generation will be pursued. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two generation expansion plans: one for the Muskrat Falls Project (Interconnected Island scenario) and one for the Isolated Island scenario.

Based on an examination of the System's existing capability, the 2012 Planning Load Forecasts (PLF), and the generation planning criteria the Island system can expect capacity deficits starting in 2015 under both the Interconnected Island and Isolated Island scenarios and energy deficits in 2019. Although final sanction to proceed with the Interconnected Island scenario at Decision Gate 3 (DG3) has not been determined, analysis leading to Decision Gate 3 indicates that the Interconnected Island scenario continues to be the preferred path with a CPW preference of $2.4 billion (2012$). A decision on final sanction at DG3 is expected in 2012.

The later than expected sanctioning for the Muskrat Falls Project (Interconnected Island scenario) has led to the situation where it will soon be necessary to seek approval regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either scenario for this capacity addition would be a 50 MW combustion turbine (CT).

The analysis in this report covers only an Interconnected Island scenario including Muskrat Falls and LIL and does not consider the potential Maritime Link interconnection to Nova Scotia. Analysis associated with this link will be completed at a later date.

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:

- Maintaining two expansion plans – Hydro must be prepared for events that may delay the proposed Muskrat Falls Project or if the project is not sanctioned;
- HTGS End-of-Life –For the Isolated Island alternative Hydro must determine what is required to ensure the HTGS can be operated reliably until it is no longer required as a generating source;
- 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 concept, costs and schedules;
- Demand study as to provide confidence in overall project; and
- Reduction Initiatives – Hydro must continue to take into account the consideration of demand reduction initiatives through demand management programs and rate design.

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1.0 Introduction

This report addresses the timing of the next requirement for additional generation supply under both the Interconnected Island and the Isolated Island options and the resources available to meet that requirement. The report also identifies those 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.

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). The first option, the Interconnected Island scenario, was to replace electricity produced by HTGS with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the island. The second option, the Isolated Island scenario, was to maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on electricity produced by HTGS. These two options require significantly different strategies to implement and require the development of two separate, generation expansion plans to manage the near-term until a decision is made on which option will be pursued for future development.

The 2010 analysis indicated a $2.2 billion (2010$) preference for the Interconnected Island scenario and thus the project passed through Decision Gate 2 (DG2). Further detail on this is included in the following reports:

(1) *Independent Supply Decision Review – Navigant Consulting Ltd. – September 14, 2011*[1]

(2) *Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Nalcor Energy – November 10, 2011*[2]

(3) *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volumes 1 and 2 – Manitoba Hydro International – January 2012*[3]

[1] http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit101.pdf
[2] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm
[3] http://www.pub.nl.ca/applications/MuskratFalls2011/MHIreport.htm

Since that time, work has progressed towards DG3, which includes a refinement of the estimates from DG2. In the DG3 analysis the Interconnected Island scenario maintains a strong economic preference ($2.4 billion (2012$)) over the Isolated Island alternative.

The analysis to determine the least cost option excluded the Maritime-Island Transmission Link (MIL). Further analysis of the benefits to the island of the MIL interconnection will be provided at a later date.

2.0 Load Forecast

This review utilizes the 2012 Planning Load Forecast (PLF) as prepared by the Market Analysis section of Hydro's System Planning Department. Long-term load forecasts for the Province are prepared using Hydro's own electricity demand forecasting models that are conditioned by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. For the 2012 review, distinct load forecasts were prepared for the Island's main electricity supply alternatives:

- Interconnected Island: the Labrador - Island transmission link option including the Muskrat Falls development.
- Isolated Island: the continued Island isolated supply option.

The load forecasts were distinguished by the supply prices for each alternative and by differences in provincial economic growth expectations with and without the Muskrat Falls Project.

Some of the more important assumptions respecting existing and incremental economic activity impacting electricity demand and supply futures are:

- Vale NL nickel processing facility at Long Harbour with initial connection in 2012 and commercial production occurring across the 2013[3] to 2014 period;
- Teck mining operations at Duck Pond continuing through 2014[4];
- Development of the Hebron oil field but no natural gas or further provincial oil developments;
- Stable population outlook with net in-migration offsetting natural population declines; and
- Gradual improvement in provincial fisheries across the forecast period.

[3] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[4] Teck 2011 Annual Report.

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

Table 2-1

Provincial Economic Indicators – 2012 PLF				
		2011-2016	**2011-2021**	**2011-2031**
Adjusted Real GDP at Market Prices* (% Per Year)	Interconnected Island	1.0%	0.8%	0.8%
	Isolated Island	0.5%	0.8%	0.8%
Real Disposable Income (% Per Year)	Interconnected Island	1.4%	1.3%	1.2%
	Isolated Island	1.0%	1.2%	1.2%
Average Housing Starts (Number Per Year)	Interconnected Island	3075	2672	2115
	Isolated Island	2885	2600	2089
End of Period Population ('000s)	Interconnected Island	517	513	513
	Isolated Island	511	510	512
*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 steady 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, a single newsprint mill and oil refinery operations are maintained with the Teck mine expected to operate through 2014. The Vale nickel processing facility is scheduled to be provided a transmission connection in 2012 with commercial production expected in the 2013 to 2014 time frame.

Table 2-2

Electricity Load Growth Summary – 2012 PLF				
		2011-2016	2011-2021	2011-2031
Utility[1]	Interconnected Island	1.8%	1.2%	1.2%
	Isolated Island	1.7%	1.1%	1.0%
Industrial[2]	Interconnected Island and Isolated Island	9.4%	4.6%	2.3%
Total	Interconnected Island	3.1%	1.8%	1.4%
	Isolated Island	3.0%	1.7%	1.2%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, North Atlantic Refining, Teck, Vale and Praxair. Teck is forecast to operate through 2014.

Table 2-3 provides a summary of the 2012 PLF electric power and energy requirements for the System for the period 2012 to 2021. Similar long-term load projections are prepared for the Labrador Interconnected System and for Hydro's Isolated Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term planning load forecasts that were used to complete the generation expansion analysis.

Table 2-3

Electricity Load Summary – 2012 Island PLF						
Interconnected Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2012	1400	6408	193	1310	1581	7942
2013	1427	6565	219	1367	1632	8169
2014	1451	6637	257	1591	1691	8472
2015	1476	6720	256	1804	1721	8745
2016	1490	6794	259	1889	1736	8902
2017	1507	6816	260	1886	1755	8921
2018	1509	6805	260	1890	1757	8914
2019	1511	6840	260	1890	1760	8949
2020	1518	6906	260	1890	1766	9016
2021	1532	7002	260	1890	1781	9113
Isolated Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2012	1400	6408	193	1310	1581	7942
2013	1427	6565	219	1367	1632	8169
2014	1451	6637	257	1591	1691	8472
2015	1476	6681	256	1804	1720	8705
2016	1483	6761	259	1889	1730	8870
2017	1502	6798	260	1886	1750	8903
2018	1503	6788	260	1890	1752	8903
2019	1507	6799	260	1890	1755	8914
2020	1510	6854	260	1890	1758	8970
2021	1522	6954	260	1890	1771	9071

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 77 percent of its net capacity and 78 percent of its firm energy. In addition, Hydro also has a contract with the Government of Newfoundland and Labrador to operate and purchase energy from the generating facilities at Star Lake and on the Exploits River. 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.

Hydroelectric generation accounts for 65 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 73 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 October 2012			
* - non-dispatchable (see Section 9.1)	Net Capacity [MW]	Energy [GWh]	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay d'Espoir	592.0	2,272	2,588
Upper Salmon	84.0	492	540
Hinds Lake	75.0	290	341
Cat Arm	127.0	678	736
Granite Canal	40.0	191	238
Paradise River	8.0	33	41
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	4
Total Hydraulic	927.3	3,961	4,488
Holyrood	465.5	2,996	2,996
Combustion Turbine	100.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	580.2	2,996	2,996
Total NL Hydro	**1,507.5**	**6,957**	**7,484**
Newfoundland Power Inc.			
Hydraulic*	96.9	324	430
Combustion Turbine	36.5	-	-
Diesel	5.0	-	-
Total	138.4	324	430
Corner Brook Pulp and Paper Ltd.			
Hydraulic*	121.4	793	880
Star Lake and Exploits Generation			
Star Lake	15.0	87	144
Exploits	90.8	547	634
Total	105.8	634	778
Non-Utility Generators			
Corner Brook Cogen*	15.0	52	52
Rattle Brook*	4.0	13	15
St. Lawrence Wind*	27.0	92	105
Fermeuse Wind*	27.0	75	84
Total	73.0	232	256
Total Island Interconnected System	**1,946.1**	**8,940**	**9,828**

4.0 Planning Criteria

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

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

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

[5] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

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

5.0 Identification of Need

Table 5-1 presents an examination of the Interconnected Island and Isolated Island load forecasts compared to the planning criteria. It does not 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 accurate 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. The table shows that under both the Interconnected Island and Isolated Island scenarios, capacity deficits (LOLH exceeding 2.8 hours per year) start in 2015 and energy deficits in 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.

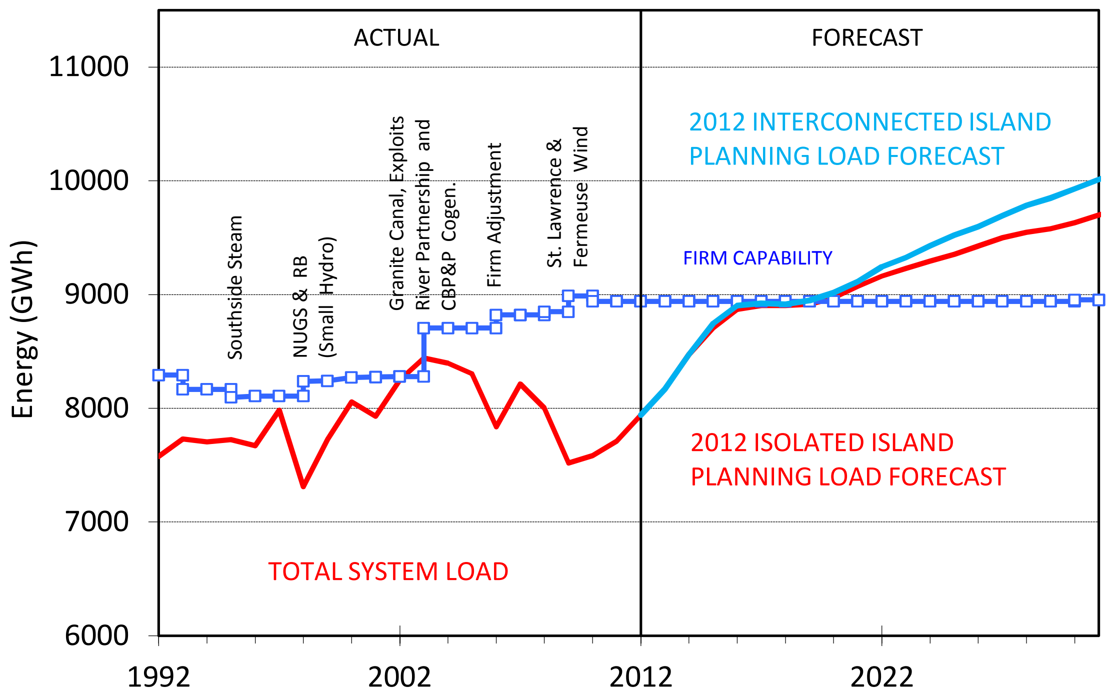
It should be noted that the capacity deficits trigger the need for the next generation source by late 2014 under the current planning criteria to avoid exceeding the LOLH limits in 2015.

Table 5-1 – Load Forecast Compared to Planning Criteria

Year	Load Forecasts				Existing System		LOLH (hr/year) (limit: 2.8)		Energy Balance (GWh)	
	Maximum Demand (MW)		Firm Energy (GWh)		Installed Net Capacity (MW)	Firm Capability (GWh)	Inter-connected Island	Isolated Island	Inter-connected Island	Isolated Island
	Inter-connected Island	Isolated Island	Inter-connected Island	Isolated Island						
2012	1,581	1,581	7,942	7,942	1,946	8,940	0.41	0.41	998	998
2013	1,632	1,632	8,169	8,169	1,946	8,940	0.97	0.97	771	771
2014	1,691	1,691	8,472	8,472	1,946	8,940	2.59	2.59	468	468
2015	1,721	1,720	8,745	8,705	1,946	8,940	4.57	4.39	195	235
2016	1,736	1,730	8,902	8,870	1,946	8,940	6.02	5.47	38	70
2017	1,755	1,750	8,921	8,903	1,946	8,940	7.59	7.07	19	37
2018	1,757	1,752	8,914	8,903	1,946	8,940	7.64	7.17	26	37
2019	1,760	1,755	8,949	8,914	1,946	8,940	8.09	7.52	(9)	(26)
2020	1,766	1,758	9,016	8,970	1,946	8,940	8.85	7.89	(76)	(30)
2021	1,781	1,771	9,113	9,071	1,946	8,940	11.34	9.97	(173)	(131)

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the Interconnected Island 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 were screened and 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.

In Nalcor's submission to the Board, *Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Nalcor Energy - November 10th, 2011*[7], other options and fuel sources that have been considered and screened out were discussed. As a result, they have not been included in this 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, then onto the intake and powerhouse, finally

[7] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm

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. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Portland Creek and Island Pond Hydroelectric Projects – Update Cost Estimates – SNC-Lavalin – June 2012*).

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. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Portland Creek and Island Pond Hydroelectric Projects – Update Cost Estimates – SNC-Lavalin – June 2012*).

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. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Round Pond Hydroelectric Development – Update of the 1988 Cost Estimate – Hatch – May 2012*).

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. 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. Based on analysis completed by Hydro in 2004 and documented in the report titled: *An Assessment of Limitations For Non- Dispatchable Generation On the Newfoundland Island System – Newfoundland and Labrador Hydro – October 2004*[8], the maximum allowable wind generation on the Isolated Island system had been limited to 80 MW.

In 2012 Hydro completed an internal study titled: *Wind Integration Study-Isolated Island: Technical Study of Voltage Regulation and System Stability – Newfoundland and Labrador Hydro – August 18, 2012*[9]. This study updated the technical analysis completed in 2004 and established new technical wind integration limits. Hatch consultants were then contracted to complete a study titled: *Wind Integration Study – Isolated Island – Hatch – August 7, 2012*[10] to assess how much additional non-dispatchable wind generation could be added, economically and technically to the Island power system. Hatch completed a review of Hydro's technical analysis as well as a detailed hydrology assessment that aided in their recommendation.

The Hatch study concludes that a total wind generation penetration by the year 2035 of approximately 300 MW yielding a 10 percent energy penetration is consistent with a high penetration in isolated power systems. The 10 percent energy penetration can be achieved through the addition of 225 MW of new wind generation in addition to the existing 54 MW of

[8] http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit61.pdf
[9] http://powerinourhands.ca/pdf/WindIntegration.pdf
[10] http://powerinourhands.ca/pdf/HatchWindIntegrationStudy.pdf

installed capacity. This new generation has been added to the Isolated Island expansion in the following increments:

- 2015 50 MW
- 2020 50 MW
- 2025 50 MW
- 2030 50 MW
- 2035 25 MW

Additional wind was not incorporated in the Interconnected Island case. However, wind could be built for export and this option will be analysed at a later date.

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. Cost estimates were reviewed in 2012 and found to be consistent with current industry estimates.

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 No. 2 diesel fuel, a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered. 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 the reduced risk of loss of multiple generation sources in the event of major events.

In either alternative, the power rating being considered is a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 1,340 GWh for the 170 MW unit.

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 was based on the 2012 update (*Newfoundland and Labrador Hydro – 170 MW CCCT and 50 MW CT Facilities – High Level Cost Estimates and Schedules – Hatch – May 2012*) of the *Combined Cycle Plant Study Update, Supplementary Report – Acres International* which was completed in November 2001.

6.6 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 diesel fuel 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 the 50 MW CT is based on the *Newfoundland and Labrador Hydro – 170 MW CCCT and 50 MW CT Facilities – High Level Cost Estimates and Schedules – Hatch – May 2012*).

6.7 Muskrat Falls Project (Labrador – Island Transmission Link)

Development of the Muskrat Falls Project would include:

- the 824 MW capacity Muskrat Falls generating facility with interconnecting HVac transmission facilities between Muskrat Falls and Churchill Falls; and
- the Labrador-Island Transmission HVdc Link and associated island system upgrades.

Schedule and Cost Estimate Basis

It is expected that this project would be completed in 2017.

A summary of the capital cost estimate for this project is available in the backgrounder: *Capital Cost Summary DG2 to DG3 – Government of Newfoundland and Labrador – November 2012*[11]

[11] http://www.powerinourhands.ca/pdf/Capital Cost and CPW Summary.pdf

A more complete description can be found in Nalcor's submission to the Board, (*Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Volume 2 - Nalcor Energy - November 10th, 2011*)[12] and *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – Manitoba Hydro International – October 2012*[13]

[12] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm
[13] http://www.powerinourhands.ca/pdf/MHI.pdf

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.

In the Province's Energy Plan, Hydro was directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option was based on replacing the HTGS with energy from the Muskrat Falls development via an HVdc link to the Island. The second option was based on an isolated island system, 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 Interconnected Island 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 a 7.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2012.

Based on the study assumptions outlined previously, the least-cost[14] generation expansion plans, under the two scenarios, is shown in Table 7-1 and graphically in Figures 7-1 and 7-2. Currently, the least-cost expansion plan is the one based on the Interconnected Island Scenario, which has a CPW preference of $2.4 billion (2012$) over the Isolated Island scenario.

7.1 Interconnected Island Scenario

Under the Interconnected Island scenario, a 50 MW CT would be completed in 2015. This will result in a slight violation of Hydro's reliability criteria in the winter of 2014 -15. The current schedule would see the Labrador – Island Transmission Link (LIL) in operation in 2017 and this would provide Hydro's system capability requirements beyond the horizon of this expansion analysis. Hydro would purchase energy from the Muskrat Falls Project through contract arrangements with Nalcor. As well, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2025 and 2028, respectively. Holyrood would operate in a synchronous condenser mode after the LIL came in service. As well, it would provide backup generation capability until 2021, after which the steam portion of the plant would be retired.

7.2 Isolated Island Scenario

If the Muskrat Falls Project is not sanctioned, the Island will remain isolated from the North American grid. Under the Isolated Island scenario, the third and fourth 25 MW wind projects would be planned for 2015, 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 projects are considered due to the benefits of fuel displacement and emissions reductions at the HTGS.

[14] 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.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2017, Portland Creek in 2019, and Round Pond in 2021 followed by one 50 MW CT in 2024 and two 50 MW CTs in 2025. As well, 50 MW of wind would be added in each of 2020, 2025 and 2030. For the Isolated Island scenario, further additions of thermal plants and wind can be expected post 2031.

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 (Hardwoods in 2025 and Stephenville in 2028).

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

2012 Generation Expansion Plans (Preliminary)		
Year	**Interconnected Island Scenario Hydro's Alternatives (Capacity/Firm Capability)**	**Isolated Island Scenario Hydro's Alternatives (Capacity/Firm Capability)**
2012		
2013		
2014		
2015	CT (50 MW/394 GWh)	CT (50MW/394 GWh) Wind Farm (25 MW/77 GWh) Wind Farm – PPA (25 MW/77 GWh)
2016		
2017	HVdc link (823 MW)	Island Pond (36MW/172 GWh)
2018		
2019		Portland Creek (23 MW/99 GWh)
2020		Wind Farm (2x25 MW/2x77 GWh)
2021		Round Pond (18 MW/108 GWh)
2022		
2023		
2024		CT (50 MW/394 GWh)
2025	Hardwoods CT retired	Wind Farms (2x25 MW/2x77 GWh) CT (2x50 MW/2x394 GWh) Hardwoods CT Retired
2026		
2027		
2028	Stephenville CT Retired	CT (50 MW/394 GWh) Stephenville CT Retired
2029		CT (50 MW/394 GWh)
2030		Wind Farms (2x25 MW/2x77 GWh)
2031		
Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2031 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 Interconnected Island Expansion Plan vs. Load Forecast

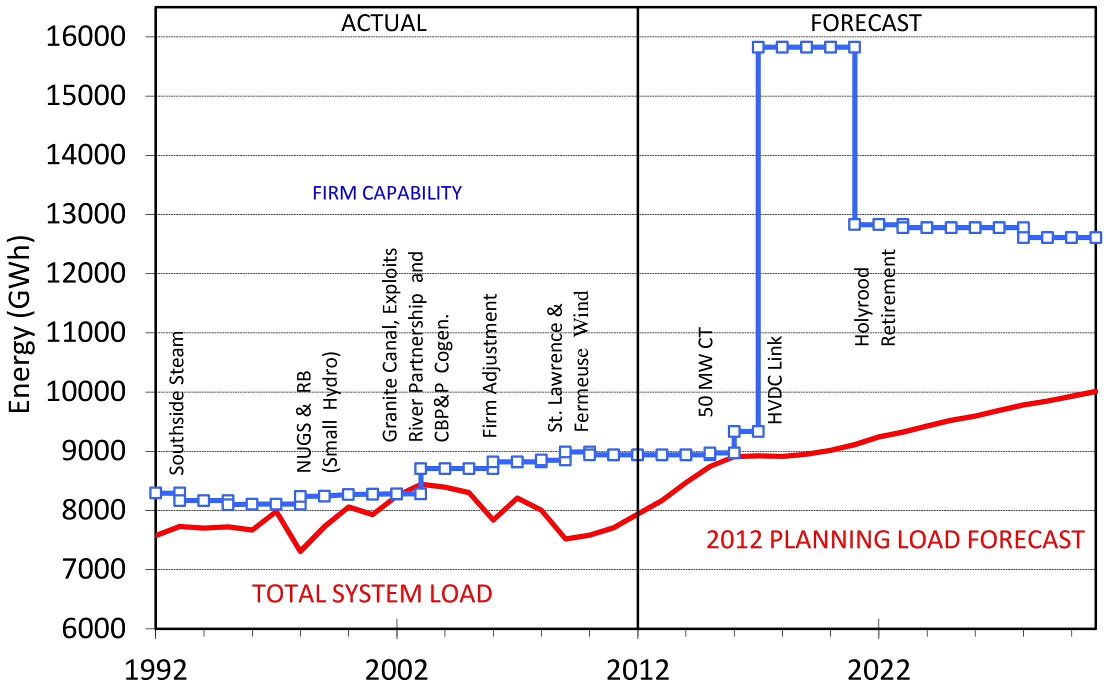
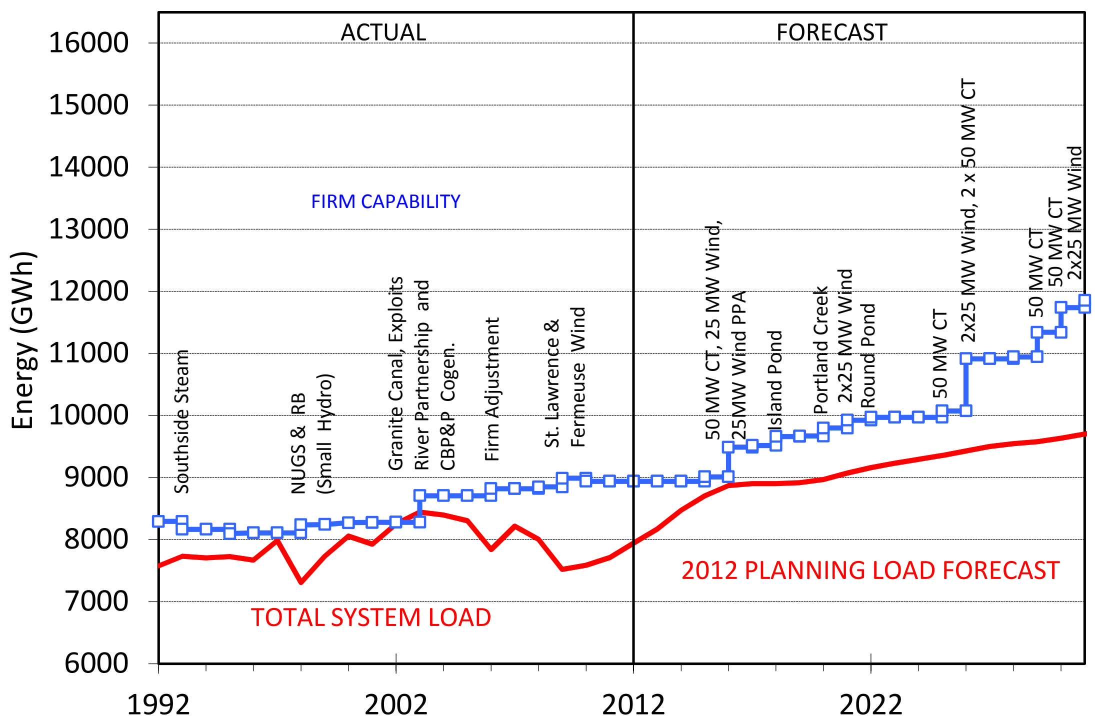


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

The later than expected sanctioning date for the Muskrat Falls Project (Interconnected Island scenario) at DG3 has led to the situation where it will soon be necessary to seek approval regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either scenario for this capacity addition would be a 50 MW combustion turbine (CT). Following the sanction decision, there should be clarity as to which expansion plan will be pursued to meet future island load requirements.

9.0 Other Issues

This section summarizes some of the issues which were considered when developing the preferred expansion plans.

9.1 Intermittent and Non-Dispatchable Resources

Based on the island's existing plus committed generating capacity, approximately 291 MW, or 15 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.

As noted in Section 6.4, Hydro recently commissioned Hatch to complete a study to determine the amount of wind that could be incorporated into the Isolated System over the next 25 to 30 years. The recommendations of the Hatch study have been incorporated in the Isolated Island expansion analysis.

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 limitation of 25,000 tonnes per year for SO_2 emissions from the HTGS (this limit cannot be exceeded burning 0.7 percent sulphur fuel at Holyrood), 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 Muskrat Falls River and a HVdc link to the Island, or by installing 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 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 808,000 tonnes per year[15] 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.

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.

[15] Based on the 5-year average of 808,000 tonnes per year of CO_2 from 2007 through 2011.

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.

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 an Interconnected Island future, these units will be required to provide system voltage support as well as to provide a backup supply for some period after the LIL 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.

Although final sanction to proceed with the Interconnected Island scenario at Decision Gate 3 (DG3) has not been given, analysis leading to DG 3 has indicated that the Interconnected Island scenario continues to be the preferred path. A decision on final sanction at DG3 is expected later in 2012. To this end, Hydro has been concentrating on condition assessments and the formulation of requirements to get Holyrood to the end of its life as a generating facility, several years after the LIL comes in-service, and to operate in synchronous condenser mode from LIL in-service.

9.4 Energy Conservation

The takeCHARGE portfolio of programs for residential customers has been operating since 2009 with increased participation in 2011 from previous years with continued rebates for several energy efficiency products for eligible residential customers. Commercial incentives were launched in 2010, offering price reduction of more efficient lighting products through lighting product distributors. The commercial lighting program has also experienced growth in participation since launch. The Industrial Energy Efficiency Program (IEEP) was launched in 2010 and targets Hydro's transmission level customers with incentives for custom projects to address their unique issues. Program participation has been slow but the first project was completed in 2011 with other proposed projects progressing through various stages from engineering feasibility to commissioning. Additional projects are expected to be completed in 2012.

In addition to the joint utility portfolio, Hydro has taken steps to implement additional efficiency programs. In 2010/11, Hydro piloted a program enabling consumers to purchase a wider range of smaller efficient household products and also provided information to customers to educate them about finding new ways to conserve. As well in 2009 and in 2011 Hydro partnered with the Provincial Department of Natural Resources to deliver a community based energy efficiency program in several Coastal Labrador communities. These pilot projects were undertaken to explore the impact of community based interventions on energy efficiency. Based on the experience gained from these pilot programs, Hydro has recently launched a three year direct install program for all isolated systems providing a host of initiatives for existing residential customers as well as providing information and low cost technologies for installation by commercial customers. Supplementing this isolated systems program is a custom program for commercial customers. In addition to the rebate programs, work continues on outreach and awareness efforts with customers, retailers and builders to ensure participation in the programs.

In September, an updated Five year Conservation and Demand Management (CDM) plan, *Five-Year Energy Conservation Plan: 2012-2016*, was filed with the Board by Newfoundland Power as part of their General Rate Application. This continues the takeCHARGE joint utility effort and expands the existing portfolio of programs. The final design work will be completed and the programs implemented upon Board approval.

10.0 Conclusion

Based on an examination of the System's existing capability, and the generation planning criteria, the System can expect capacity deficits starting in 2015 and energy deficits in 2019 under both the Interconnected Island and Isolated Island scenarios.

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 Muskrat Falls Project can be reached. These two expansion plans mainly differ based on the inclusion of an HVdc link (LIL) as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Muskrat Falls Project is scheduled for late 2012 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. However, analysis leading to DG3 has indicated that the Interconnected Island scenario remains the preferred path, with a CPW preference of $2.4 billion (2012$).

In the near term, approval will be sought regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either the Interconnected Island or the Isolated Island scenario for this capacity addition would be a 50 MW combustion turbine (CT).

The analysis in this report covers only an Interconnected Island scenario including Muskrat Falls and LIL. It does not consider the potential Maritime Link interconnection to Nova Scotia. Analysis associated with this link will be completed at a later date.

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.

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan: 2012-2016* 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 electricity produced at HTGS 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:

- Maintaining two expansion plans – Hydro must be prepared if events delay the proposed Muskrat Falls 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 until it is no longer required as a generating source;
- 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.
- Reduction Initiatives – Hydro must continue to take into account the consideration of demand reduction initiatives through demand management programs and rate design.

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Appendix A

Table A-1
2012 Island Planning Load Forecast

	Interconnected Island Case		Isolated Island Case	
Year	Demand [MW]	Firm Energy [GWh]	Demand [MW]	Firm Energy [GWh]
2012	1581	7942	1581	7942
2013	1632	8169	1632	8169
2014	1691	8472	1691	8472
2015	1721	8745	1720	8705
2016	1736	8902	1730	8870
2017	1755	8921	1750	8903
2018	1757	8914	1752	8903
2019	1760	8949	1755	8914
2020	1766	9016	1758	8970
2021	1781	9113	1771	9071
2022	1801	9243	1790	9161
2023	1824	9325	1807	9230
2024	1841	9429	1821	9293
2025	1861	9522	1834	9353
2026	1879	9595	1848	9426
2027	1894	9692	1862	9498
2028	1912	9783	1875	9546
2029	1929	9848	1886	9579
2030	1942	9930	1894	9631
2031	1958	10012	1905	9700