Date : 7/15/2012 8:49:18 PM
From : "Bown, Charles W."
To : "Scott, Paul G." , "McGrath, Rob" , "Snook, Corey"
Subject : MF papers
Attachment : Scanned from a Xerox multifunction device001.pdf;

The Ministers comments are attached. Good job tonite;thanks for coming in on such a nice day.
Charles

Sent Via BlackBerry

----- Original Message -----
From: 031357@gov.nl.ca <031357@gov.nl.ca>
To: Bown, Charles W.
Sent: Sun Jul 15 21:10:29 2012
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Perhaps should have 2 papers — (1) Demand / need (2) Electricity rates.

Island Electricity Demand and Rates Forecasting

Department of Natural Resources

May 2012

Do we need the power?

— Rates with Mobilize then reduce versus Holyrood option

(3) Then review of options.

Demand — even if Holyrood refurbished does nothing for mining & Lab

— Muskrat Falls meets these demands and many.

Introduction needs to be simpler

Long Term Planning Forecast

To ensure that sufficient utility generation resources and reliability standards are provided for as per PUB direction, Newfoundland and Labrador Hydro (NLH) projects electric power demand and energy requirements twenty years into the future. This projection is published annually in the long-term Planning Load Forecast (PLF). Nalcor has used a generation expansion analysis to extrapolate this twenty year outlook over the fifty-year life span of the Muskrat Falls project. An independent review by Navigant found that the 50 year generation expansion analysis period used by Nalcor was appropriate given the long-lived supply options being analyzed. → outline specific reference

The load forecast in the PLF is segmented by Island and Labrador interconnected systems and rural isolated systems. Loads are further segmented by domestic (residential), general service (commercial) or industrial load (i.e. large customers purchasing power from the bulk electricity grid such as Corner Brook Pulp and Paper and North Atlantic Refining Ltd.).

While demand for electricity is primarily driven by the level of economic activity, energy prices also have a role to play, especially with respect to space-heating fuel choice. Since the 1980's, there have been simultaneous increases in the real cost of oil heating, the preference for electric-based heating systems and the penetration of electric heat in new construction. These increases have resulted in a projected relative price advantage for electricity in the long term which is expected to sustain the preference for electric heat over the PLF. A second notable feature is the significant increase in load associated with nickel processing facilities on the island. This new industrial load, combined with projected increases in utility load, offsets the recent declines in industrial load where total Island requirements are forecast to surpass 2004's historic peak energy requirements by 2016.

Provincial Power Systems

The load forecast is segmented by Island and Labrador interconnected systems as well as rural isolated systems in both Newfoundland and Labrador. Loads are further distinguished by utility load (i.e., domestic and general service) and industrial load (i.e. Corner Brook Pulp and Paper and North Atlantic Refining Ltd.).

Island Interconnected System

Total Island load is the sum of the interconnected residential, commercial and industrial load, less any power and energy losses from transmission and distribution activities. Domestic customers on the Island Interconnected system represent approximately 90% of the province's customer base and account for 60% of total utility sales. Across all households, regardless of space heating equipment, there is a common level of demand. What distinguishes one residential consumer from another with respect to consumption is the presence or absence of an electric hot water heater and the presence or absence of electric heating. Baseline (non-heating) demand, driven by lighting and household appliances such as refrigerators, microwaves, and washers and dryers, is expected to remain at or near current levels due to the near-saturation of these technologies in the local housing stock.

In addition to the domestic load, commercial (general service) customers' electricity sales account for about 40% of total utility sales and are highly dependent on real changes in real provincial GDP, building stock and heating requirements. As in the domestic sector, a preference for electric space heating exists, with virtually all new general service facilities relying on electricity-based heating systems. The industrial load has remained largely unchanged over the past several years and historically, this demand has come largely from three pulp and paper mills which comprised 30% of the Island Interconnected load. However, with the closure of the newsprint mills in Stephenville and Grand Falls, and the reduction in paper production at the Corner Brook mill, industrial demand and energy requirements are less than half of what they once were. With respect to the 2010 PLF, industrial demand is expected to sustain current levels. Industrial demand comes largely from ongoing operations at Corner Brook Pulp and Paper, which is forecast to be in the order of 26 MW in addition to their generation capability at Deer Lake. The other large source of industrial demand on the island is North Atlantic Refining Ltd., which operates an oil refinery at Come-By-Chance and has a peak demand of 31 MW. The third account is Teck Resources' copper-zinc mine and mill near Millertown, which is expected to remain in operation through 2014, with a peak demand of 10 MW. Finally, an 80 MW hydrometallurgical industrial load is provided for the Vale Inco nickel processing facility.

Labrador Interconnected

The Labrador interconnected load refers to all electricity loads connected to the Churchill Falls hydroelectric generating station. These include the community loads of Happy Valley/Goose Bay, Wabush, Labrador City and the Churchill Falls town site. The major load centre is Labrador West, due to the presence of the large industrial iron ore mining and processing operations at Wabush Mines and IOC. The majority of this load is met through the Twin Falls Power Company (TwinCo), which is owned by CF(L)Co and the above mines, and provides 225 MW to Wabush Mines and IOC. In addition, IOC has increased its power supply to support its operations through a 62 MW power contract with Hydro. Wabush Mines also has contracts with Hydro for very small amounts of required power over and above their TwinCo allotment.

Labrador East also has significant demand. Hydro sells secondary electricity to CFB Goose Bay for its steam-raising boiler which provides heating services to the military base. Although this load has been in decline since the mid 1990's due to base infrastructure rationalization and power transfer constraints during the winter, these secondary sales, in combination with firm power sales to the Department of National Defence, can represent over 35 percent of Hydro requirements for Labrador East. These sales are expected to continue over the PLF period. Despite mixed economic indicators, both the eastern and western regions of Labrador are expected to experience load growth. Taken together, the Labrador interconnected load is presently about 450 MW and 3,000 GWh per year.

There are a significant number of potential mining projects in Labrador that could require power above and beyond this load between now and 2019. Preliminary economic assessments and feasibility studies suggest that most of these projects are economic, based on conservative forecasts of future iron ore prices, and it may be the case that many of these projects will progress. Alderon Iron Ore (65 MW),

Grand River Iron Sands (135 MW) and IOC (14 MW) could require an additional 214 MW in 2015; more power than is available through existing capacity. If the IOC Genesis project and Tata Steel Canada's LabMag project were to go into operation in 2016, then an additional 371 MW would be required. If all projects go ahead, there could be over 1000 MW required to power these mines. There is currently between 80 and 280 MW of recall power available over and above current needs depending on the time of year, with the average being 140 MW. If Muskrat Falls is sanctioned and constructed on schedule, a further 230 MW will be available in 2017.

Capacity (or peak) refers to the highest level of electricity consumption that the utility can supply at any one time. For residential customers, capacity is measured in kilowatts (kW). Peak demand on the electrical system is measured in megawatts (MW). Energy (or consumption) refers to the total amount of electricity that the utility supplies throughout the year. In the home, the amount of energy used is measured in kilowatt hours (kWh); to Hydro industrial customers, it is measured in gigawatt hours (GWh). Peak output at Muskrat Falls is 824 MW. This is the plant's capacity, or the power the plant can produce at any given time to service customers' demand, or load. However, the plant does not produce the 824 MW every hour of every day that it is capable of producing. If the plant was to produce at full capacity all of the time, the energy output would be 7,218,240 MWh, or 7.2 TWh, per year. However, because the plant is not operating at capacity all of the time, the energy output is smaller, as it aligns more closely with how customers actually use electricity. The actual energy output of Muskrat Falls is 4.9 TWh per year. However, the plant must always be capable of meeting peak demand in the event that customers demand it. Even if this occurs only once during the year for one hour, the plant must be able to produce 824 MW at any time.

Isolated Systems

The Isolated system serves approximately 4,370 domestic and general service customers in twenty-one isolated areas of the province. The electrical supply source of isolated systems is primarily diesel, with the exception of the L'Anse au Loup system where an interconnection with Hydro-Quebec largely meets the region's power requirements. Total demand from those isolated customers outside of the L'Anse au Loup system is approximately 9 GWh and demand is expected to decline only slightly over the 2010 PLF. The fifteen Labrador diesel systems have an aggregate net consumption of 55 GWh with continued load growth expected over the long term.

Total Provincial Load

Non-coincident demand, which is the combined peak demand of all the components of the provincial system, is currently around 2,000 MW with associated energy of 10 TWh annually. Over the 2010 PLF, overall load growth for the Island Interconnected system is expected to increase by 1.3 percent annually between 2009 and 2029, on average. The isolated diesel load on the island is forecast to decline over the same period, while the isolated diesel load in Labrador is forecast to grow by 1.5 percent annually. Overall, provincial electricity load is projected to grow in line with the Island Interconnected requirements at 1.3 percent annually.

The projected growth in electricity load over the PLF is driven in large part by an increase in the number of residential customers. The number of residential customers has continued to grow, reaching 230,000. More people are purchasing houses than in the past, and fewer people are occupying each house. This phenomenon means an increase in the amount of space that requires heating, and thus an increase in demand, despite a decline in the overall population. The market share of electric heat has more than doubled between 1979 and 2009, with 86 percent of new homes now choosing electric heat as their heating source.

Current generating capacity for the Island generating system is 1,958 MW, with NL Hydro providing 1,518 MW of power. According to the PLF, by 2015, there will be a capacity deficit. This means that there will not be enough power to meet peak demand in the middle of winter. By 2020, Nalcor forecasts an energy deficit. This means there will not be enough energy-producing capability to meet demand over the year. These anticipated deficits, combined with electricity demand for mining developments in Labrador, mean that additional power is required by 2015, in order to meet demand and the reliability standards as set by the PUB.

Table 1: Interconnected Island Load Forecast

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Requirements (GWh)	7,585	7,709	7,850	8,214	8,488	8,608	8,626	8,666	8,735	8,806	8,872	8,967	9,065	9,171	9,235	9,293
Growth Rate (%)	2.2	1.6	1.8	4.6	3.3	1.4	0.2	0.5	0.8	0.8	0.8	1.1	1.1	1.2	0.7	0.6
Peak Demand (MW)	1,519	1,538	1,571	1,601	1,666	1,683	1,695	1,704	1,714	1,729	1,744	1,757	1,776	1,794	1,813	1,827
Growth Rate (%)	-5.1	1.2	2.1	1.9	4.1	1.0	0.7	0.5	0.6	0.9	0.8	0.8	1.1	1.0	1.1	0.8

Table 2: Provincial Load Forecast

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	20
Total Requirements (GWh)	10,558	10,724	10,906	11,296	11,578	11,703	11,725	11,768	11,840	11,913	11,982	12,080	12,179	12,288	12,353	12,
Growth Rate (%)	6.4	1.6	1.7	3.6	2.5	1.1	0.2	0.4	0.6	0.6	0.6	0.8	0.8	0.9	0.5	0.5
Peak Demand (MW)	1,992	2,013	2,047	2,078	2,145	2,162	2,175	2,186	2,196	2,212	2,228	2,242	2,261	2,281	2,300	2,3
Growth Rate (%)	-3.2	1.0	1.7	1.5	3.2	0.8	0.6	0.5	0.5	0.7	0.7	0.6	0.9	0.9	0.9	0.6

Island System Capability

Hydro is the main supplier of electricity on the Island Interconnected System, providing 78 percent of the capacity and 78 percent of the firm energy. Hydroelectric generation provides 62 percent of the firm capacity on the system, the Holyrood Thermal Generating Station provides 31 percent, and combustion turbines (burning light fuel oil) provide the remaining 7 percent.

The PUB has approved criteria related to the appropriate reliability of the generation fleet on the Island. The reliability standard requires that Hydro install enough generation to probabilistically result in 2.8 hours (or less) per year with insufficient generation available. This equates to having enough generation available at least 99.97 percent of the time. To meet this standard, and to ensure that it has an adequate supply of generation to meet peak system demand, Hydro maintains capacity and energy reserves (effectively a generation "buffer"). This buffer size depends on the reliability of the units in use, but is approximately 15 percent in the current Island system. In 2012, for example, Hydro's 1,958 MW of installed generation is sufficient to meet expected peak demand of 1,571 MW which equates to only 0.41 hours of insufficient supply per year. This is well within the approved reliability standard as set by the PUB.

What does Navigant/Nalcor say about this?

However, under current demand forecasts and without new generation, by the year 2015, Hydro will exceed its maximum allowable threshold of 2.8 hours with insufficient generation. Therefore, Hydro sets the timing of its generation additions to ensure compliance with the reliability standard. Hydro must also ensure that there is adequate annual firm energy available to meet the needs throughout the year. To ensure security of supply, firm energy for hydroelectric plants is calculated using the most adverse three-year sequence of reservoir inflows (i.e. the driest three years) occurring within the historical record.

Key

Peak

Hydro has developed two generation expansion plans to meet the projected demand on the Island. One plan, the Isolated Island, relies primarily on life extensions at the Holyrood plant, with some small hydroelectric and wind additions. The second option, Muskrat Falls and the Labrador-Island Link, involves connecting hydroelectric generation in Labrador to the Avalon Peninsula via a high-voltage direct current transmission line. Each proposed generation expansion plan has its own set of costs that would be passed on to electricity ratepayers.

How Rates are Set

Electricity rates

In Newfoundland and Labrador, electricity rates are set according to a utility's annual revenue requirement; that is the amount of money it must take in to cover all legitimate expenses (including the cost of capital) and to maintain a sound financial position. The PUB determines Hydro's revenue requirement by examining its capital and operating costs. The PUB also sets the allowed rate of return on rate base (i.e. the physical assets purchased through capital such as power plants, transmission lines, substations, vehicles, and buildings). Rates are then set at a level that will provide the total required revenue.

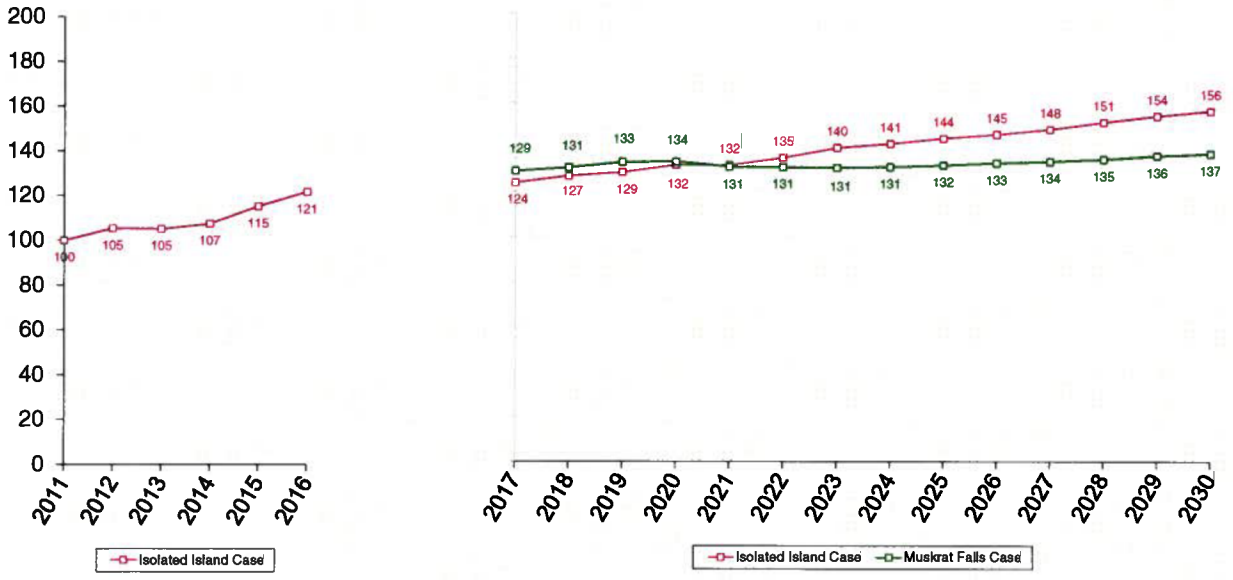
Rates Projections

Since Hydro maintains a forecast of all costs associated with each generation expansion plan, it can calculate the annual revenue requirement for each future year in each of the two alternative scenarios in the Muskrat Falls decision gate two (DG2) analysis. In the Isolated Island plan, 40 to 50 percent of the total revenue requirement in each future year is directly attributable to fuel costs at Holyrood. In the Muskrat Falls plan, fuel costs drop to near zero after 2017, when Holyrood comes offline, and 55 to 65 percent of the total revenue requirement is driven by power purchases from Nalcor's Muskrat Falls subsidiary and the associated transmission costs.

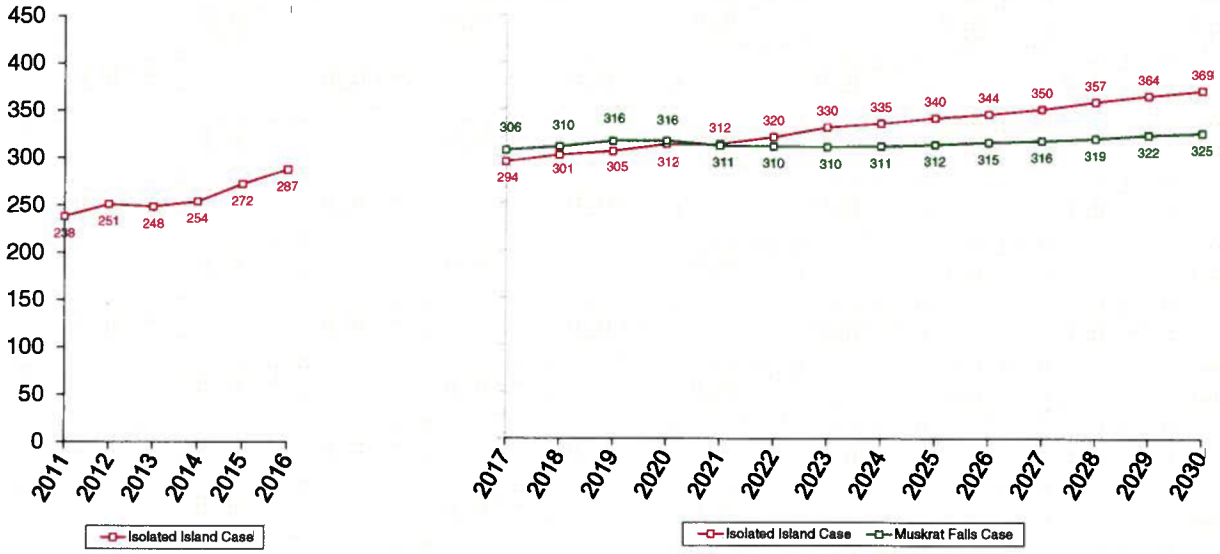
To illustrate the effects of the Isolated Island and Island Interconnected scenarios for residential ratepayers, average monthly bills are then calculated for three unique residential demand profiles. The first profile represents an average customer who does not use electric space heating. About 90,000 Island electricity customers, or 39%, meet this definition. The second profile is for the average customer with electric heat. About 140,000 Island customers, or 61%, fall in this category. The third profile is the all-in average consumption level for all residential electricity accounts on the Island (1,517 kWh of electricity per month). The average monthly bill for each of these customer profiles, by year, is shown below. All figures include taxes, and reflect the provincial HST rebate for years 2011 and beyond. Data points up to 2011 indicate actual rates in effect at July 1 of each year; 2012 shows rates in effect as at January 11, 2012; data for 2013 and later is based on forecasts as per DG2 data (November 2010).

The following charts show the latest available rates forecasts (in average monthly bill amounts) for both the Isolated Island option (in red) and the Muskrat Falls option (in green).

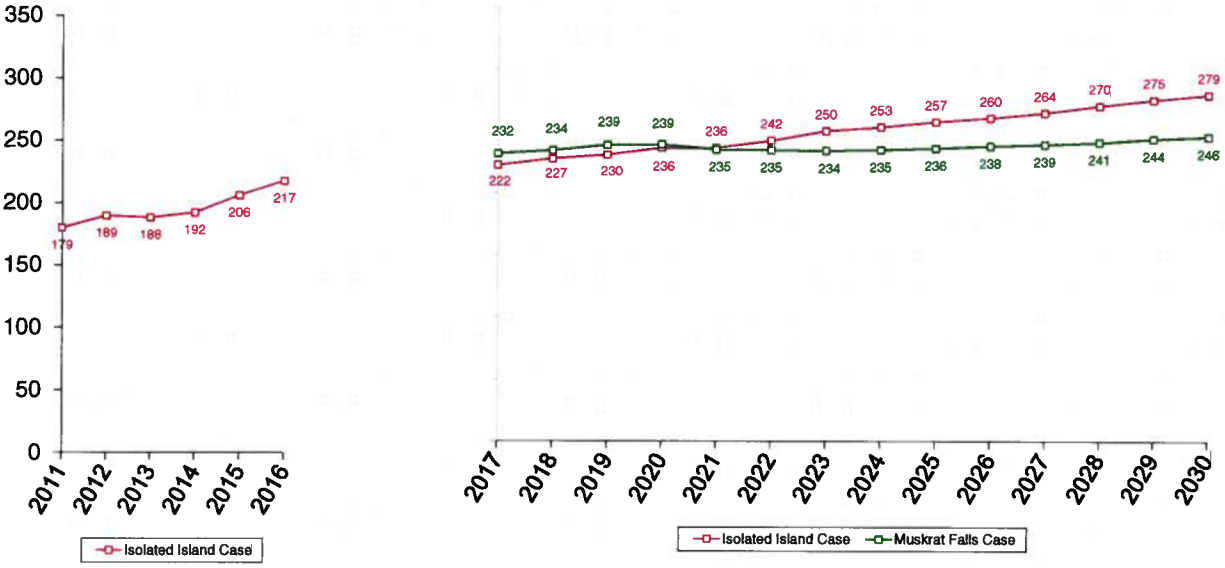
Profile 1: Average of 90,000 customers without electric heat



Profile 2: Average of 140,000 customers with electric heat



Profile 3: Average of all Island residential customers



Analysis

Based on the above charts, it is clear that beginning in 2021, and out to 2030, all three profiles will experience an increase in their average monthly heating bill under both the Isolated Island and Muskrat Falls cases. In 2030, under the Isolated Island option, the average monthly bill for all island customers will increase by $43 (18%) from $236 in 2021, to $279 in 2030. Under the Muskrat Falls case, the average monthly bill for all Island customers will increase by only $11 (4%) from $235 in 2021, to $246 in 2030.

It is important to note that the Muskrat Falls case protects customers from the significant increases they would experience under the Isolated Island case. In addition, the Muskrat Falls case provides customers

with stable rates out to 2030, compared with the Isolated Island case, and the gap between the two cases increasingly widens over time.

Decision Gate Process

Nalcor is currently in the process of updating the DG2 numbers in advance of DG3. In order to undertake this process, Manitoba Hydro International has been engaged for a review of the Muskrat Falls and Labrador Island HVdc link (LIL) and the Isolated Island options for the work completed by Nalcor since Decision Gate 2 in preparation for DG3. Since DG2 in November 2010, engineering has progressed to a level required to support project sanction. The purpose of the review is to determine whether or not Nalcor's work was undertaken in accordance with Good Utility Practices whereby the processes, practices and standards used in the development of the work follows the practices, standards and processes of a majority of the utilities in Canada. MHI's review also will include an assessment of the Cumulative Present Worth (CPW) analysis of the various components for each of the two options, including a reasonable assessment of all inputs into the analysis. This includes a review of:

- load forecast updating;
- AC integration studies completed for the Muskrat Falls and LIL HVdc configuration options to establish the reasonableness of their use as DG3 cost inputs;
- Muskrat Falls GS post-DG2 design changes, cost estimates and construction schedules
- HVdc converter stations and associated AC switchyards
- Overhead HVdc transmission line and associated AC collector transmission lines including its reliability design criteria, route details and final meteorology review
- Strait of Belle Isle (SOBI) marine crossing cost estimates and construction schedule
- Other changes made by Nalcor to cost inputs from DG2 to DG3 for both the Isolated Island and Interconnected Island options
- CPW input changes and results for DG3 inputs for both the Isolated Island and Interconnected Island alternatives.

Conclusion

It is clear that demand for electricity in this province will increase over the coming decades. This demand will be driven from all sectors – residential, commercial and industrial. In order to meet this demand, the development of Muskrat Falls is an option being considered. This development will allow the province to meet the growing needs of all sectors in a clean, reliable and least-cost manner. This is of particular important for the Labrador load, where a significant number of potential mining projects will drive demand more than ever before. With demand will come an increase in electricity rates. Rates are expected to increase under both the Isolated Island and Muskrat Falls cases, however the development of Muskrat Falls will protect ratepayers from the significant increases they would experience under the Isolated Island case. This case will result in stable, least-cost rates for ratepayers, with the added benefit of being a secure and renewable source for generations to come.

Electricity from Churchill Falls

Department of Natural Resources
May 2012

~~Churchill Falls~~

Upper Churchill Power as an alternative to Muskrat Falls / Do we wait until 2041?

need to distinguish clearly

as opposed to returning to Churchill Falls through market access to Upper Churchill versus Lower Churchill and New Gull Island and Muskrat Falls

Churchill Falls

NEEDS TO BE REWRITTEN

Historical Context

Shortly after confederation in 1949, Newfoundland made efforts in the United Kingdom and other parts of Europe seeking investors for development projects including Churchill Falls. In 1953, the British Newfoundland Company (Brinco) was formed as a result of these efforts. Large British concerns including N. Rothschild and Sons and Rio Tinto were key members of the consortium.[1]

Five years after the formation of Brinco, in 1958, it established a subsidiary called Hamilton Falls Power Corporation which was held 80% by Brinco and 20% by Montreal-based Shawinigan Engineering Company. This subsidiary's mandate was develop Churchill Falls, which was then known as Hamilton Falls. Upon Winston Churchill's death in 1965, the Hamilton River was renamed in his honour, and the Hamilton Falls Power Corporation became the Churchill Falls (Labrador) Corporation, or CF(L)Co.[2]

The development of Churchill Falls was to be financed through substantial long-term loans. To secure these, lenders wanted assurance that once the facilities were built, power could be taken to market. As a result, CF(L)Co needed a sales agreement before proceeding. The most obvious customer was Hydro-Quebec.[3]

[redacted]

[1] (James Feehan, Newfoundland Quarterly, Volume 101, Number 4, 2009, page 35)
[2] (James Feehan, Newfoundland Quarterly, Volume 101, Number 4, 2009, pages 35-36)
[3] (James Feehan, Newfoundland Quarterly, Volume 101, Number 4, 2009, page 36)
[4] (James Feehan and Melvin Baker, Policy Options, September 2010, Page 66; AND James Feehan, Newfoundland Quarterly, Volume 101, Number 4, 2009, page 36)

FEEHAN
What about Churchill article?

terms limited potential profits for CF(L)Co and there was no mechanism to increase price for 40 years, Hydro-Quebec's commitments reduced risks to lenders

Soon after the letter of intent was signed, CF(L)Co began a program of construction in order to have first power available to meet Hydro Quebec's requirements. This was financed mostly by bank loans and shareholders. Negotiations on a contract to implement the letter of intent proceeded slowly, however, and CF(L)Co nearly exhausted its bank credit and other sources of funds. Brinco was also in a difficult financial position. At this point Hydro-Quebec sought and received additional two concessions that were contrary to the letter of intent ~~– first, that an automatic renewal at a fixed price not subject to prior risk-reducing commitments be included and, secondly, that Hydro-Quebec receive bonus shares should it be called upon to make loans to CF(L)Co.~~[5]

The automatic renewal clause takes effect in 2016 and provides for automatic renewal at the expiry date for a further 25-year period. During this renewal period, the price for electricity is fixed at $2 per megawatt hour (MWh). Even by the standards of the 1960's, when the contract was signed, this was an extremely low price for electricity and could not be achieved from other new energy sources then available to Hydro-Quebec. For illustrative purposes, in 2003, Hydro-Quebec received an average of $85 per MWh for its electricity exports. CF(L)Co made some attempts to resist these terms but negotiations were mostly finished by June of 1968 and the final contract was signed in May of 1969.[6] The first units at Churchill Falls were delivering power by 1971 and the project was fully completed in 1974. The total cost for the project was $950 million dollars and financing has been fully paid back.

Twin Falls Power Corporation (TwinCo)

Twin Falls are waterfalls on the Unknown River, a tributary of the Churchill River. In the 1950's, Brinco acquired hydroelectric development rights on the river and it subsequently partnered with Wabush Mines Limited and the Iron Ore Company of Canada to form Twin Falls Power Corporation (TwinCo) to deliver power to the two Western Labrador mining operations then being developed.

The power station at Twin Falls was started in 1960 and was finished in 1963. This included damming the river to create the Ossokmanuan Reservoir. When concluded the station had a total capacity of 225 MW and had two 230 kV transmission lines running 185 km to the mine sites. The station was built at a cost of $47.5 million upon completion in 1963.

Twin Falls power supplied power during the construction phase of the Churchill Falls power development, but during planning it became obvious that it would be more efficient in terms of electricity production to divert the flow of water from the Ossokmanuan Reservoir into the Smallwood Reservoir associated with the Churchill Falls development. In July 1974 the Twin Falls plant was closed and the water was diverted into the Smallwood Reservoir. Churchill Falls

[5] **(James Feehan, Newfoundland Quarterly, Volume 101, Number 4, 2009, page 37)**
[6] **(James Feehan and Melvin Baker, Policy Options, September 2010, Page 65-66)**

has been able to produce approximately three times more electricity as would have been possible at the Twin Falls plant from the diverted water. A 225 MW "TwinCo block" of power continues to be supplied to TwinCo, although this requirement expires on December 31, 2014.

Pre-August 31, 2041

Several of CF(L)Co's major contracts, which expire on August 31, 2041, largely set the course for the Corporation over the next 30 years. The Power Contract with Hydro-Quebec provides for the sale to Hydro-Quebec of the vast majority of energy produced at the Churchill Falls Plant at a price which has declined through the life of the contract thus far and which will be a firm price after 2016. The power and energy which CF(L)Co recalls under the Hydro-Quebec Power Contract, the Recapture, will be sold to NLH pursuant to an additional power contract between CF(L)Co and NLH, which expires August 31, 2041.

The Guaranteed Winter Availability Contract obligates CF(L)Co to provide any additional capacity available in the winter months to Hydro-Quebec. In addition, the Shareholders' Agreement limits certain aspects of the company's operations and provides the minority shareholder with certain powers through requirements for its approval, both in its capacity as shareholder and through its nominees on the CF(L)Co Board.

Notwithstanding the August 31, 2041 expiry of several major contracts, there is a near-term change in the status quo that will likely result in increased revenues for CF(L)Co. Its obligation to provide 225 MWs to Twin Falls Power Corporation Limited expires at the end of 2014. The Shareholders' Agreement stipulates that this power is to then be sold by CF(L)Co to NLH at a "commercially reasonable" price. This price will likely be significantly higher then the price at which the Twinco block of power is presently sold to Twinco and consequently revenues to CF(L)Co from the sale of this power will increase.

With respect to the operation and maintenance of the plant prior to September 1, 2041, it is the responsibility of CF(L)Co to carry out these activities. It will operate and maintain the plant and pay for the work associated with these activities. The approval of annual budgets requires approval of the CF(L)Co Board of Directors, who are required to act in the best interests of CF(L)Co.

Post-August 31, 2041

The expiry of the power contract between CF(L)Co and Hydro-Quebec in 2041 will be an opportunity for our province in terms of the potential to access both the power and the economic returns that Churchill Falls can provide. However, it is incorrect to assume that in 2041, the province will have unfettered control over the power produced by Churchill Falls. The development is not, nor will it likely be post-2041, exclusively owned by the Province.

It is true that after August 31, 2041, CF(L)Co will have more freedom to operate in the nature of a privately owned power utility. It will be much less restricted with respect to its operations as they relate to the Shareholders' Agreement, as that Agreement will have expired. CF(L)Co's by-laws will require the approval of both shareholders in some instances, but overall these are

much less restrictive. Its obligations relating to the sale of power to both Hydro-Quebec and NLH will have expired, leaving CF(L)Co with flexibility in relation to the sale of the power and energy it produces. The Corporation will continue to own the plant and own the water rights until such time as the Water Lease expires.

Additionally, with respect to the sale of power and energy after August 31, 2041, the expiration of the Shareholders' Agreement removes restrictions contained in that Agreement on CF(L)Co's internal governance and operations, which should allow the Province, through NLH, to more freely deal with CF(L)Co in this regard.

However, the Province may not have, and cannot at this time rely upon having, unilateral authority to deal with Churchill Falls as its own asset. Hydro-Quebec's position as a minority shareholder places it in a position to rely upon corporate law remedies to ensure it is not being oppressed through the actions of the majority shareholder. It is also able to ensure that actions carried out by the CF(L)Co Board are in the best interests of CF(L)Co. As a result, the implementation of public policy objectives may be complicated by the corporate structure of CF(L)Co. CF(L)Co is owned by Newfoundland and Labrador Hydro and Hydro-Quebec, with NLH owning 65.8% of the common shares and Hydro-Quebec 34.2% of the common shares.

Churchill Falls as an Alternative to Muskrat Falls

To meet the province's future energy needs, Nalcor has assessed the option of deferring the interconnection between Labrador and the Island to 2041, once the power contract between CF(L)Co and Hydro-Quebec expires, and then accessing Churchill Falls power. This would require maintaining the isolated Island system until that time, followed by the construction of a transmission interconnection with Labrador.

In its assessment, Nalcor concluded that, in comparison to the Interconnected Island scenario, the deferred interconnection option is not economically justified as the Cumulative Present Worth (CPW) premium for deferral over the Interconnected Scenario (construction of Muskrat Falls and the Labrador Island Transmission Link) is approximately $1.3 billion.[7] Nalcor has identified other concerns with this option as follows:

<u>Security of supply and reliability</u>

- Guaranteeing the availability of supply from Churchill Falls in 2041 is uncertain because it is difficult to determine the environmental and policy frameworks that will be in place 30 years from now;
- Nalcor is not the sole shareholder of Churchill Falls, as described above;
- There is significant risk associated with maintaining reliable supply through continued life extension measures for Holyrood generating station through to 2041. At that time, the first two units at Holyrood will be 70 years old.

[7] MHI-Nalcor-3

Cost to ratepayers

- Deferral of the interconnection would result in significantly higher rates for Island consumers between now and 2041 and does not provide rate stability to Island consumers as rates are tied to highly volatile fossil fuel prices for the first 30+ years of the study period along with escalating maintenance costs for Holyrood and an increasing likelihood that replacement of the plant will be required prior to 2041.

Environmental compliance

- Island customers will remain dependent on fossil fuel generation for the first 30+ years of the study resulting in continued and increasing GHG emissions
- Given the Government of Canada's decision to introduce GHG emissions regulation for coal fired generating stations, Nalcor's ability to refurbish Holyrood without conforming to GHG emissions regulation is doubtful, and replacement of the plant may be required between now and 2041.

Risk and uncertainty

- Each of the screening criteria above has significant risk and uncertainty that are not present in either the Isolated or Interconnected Scenarios.
- The prospect of requiring substantial investment to Holyrood to extend its life beyond that contemplated in the Isolated Scenario, or the real possibility of requiring replacement of Holyrood and then retiring it in 2041, increases the probability that this option will be substantially more expensive than projected.

Furthermore, deferring the interconnection between Labrador and the Island to 2041 will also defer the province's ability to capitalize on the value of its energy resources for 30+ years as export revenue will be unavailable.

Conclusion

The power contract between CF(L)Co and Hydro-Quebec has been the source of great resentment for the people of the province for several decades. The price of power negotiated under that contract, along with the length of the contract itself, is wholly unacceptable and has resulted in tremendous profits for Hydro-Quebec, while returning very little to Newfoundland and Labrador.

The power contract expires in 2041, at which time, the province will obtain much more control over Churchill Falls power than currently exists, and will certainly benefit from the economic returns of that resource. However, Churchill Falls power is not exclusively owned by the province and NL will consequently not have unfettered control over the resource.

Deferring the interconnection between Labrador and the Island to 2041 is not a viable alternative to Muskrat Falls for several reasons. Maintaining the isolated Island system until that time, followed by the construction of a transmission interconnection with Labrador, is an estimated $1.3 billion more expensive (CPW) than developing Muskrat Falls. There is also considerable risk and uncertainty regarding security of supply and reliability, the cost to

ratepayers, and environmental compliance. Deferring the interconnection also means deferring the province's ability to fully capitalize on the value of its tremendous energy resources.

NEED STRONG CONCLUDING SENTENCE

ANNEX A - Principle Legal Documents

The following is a listing and summary of the principle documents that facilitate the supply of power from Churchill Falls to Hydro Quebec.

Water Lease Between the Government of Newfoundland and CF(L)Co - May 16, 1961 ("Water Lease")

- This lease gives CF(L)Co the right to the waters of the catchment area of the upper Churchill River and the exclusive right to harness the River to produce hydroelectricity. CF(L)Co is also given the right to do what is necessary in the development, transmission and supply of hydroelectric power produced on the upper Churchill River, which would include the right to construct dams and acquire Crown Land.

- The term of the Water Lease is 99 years renewable (at CF(L)Co's option) for another 99 years.

- CF(L)Co is required to pay to the Province an annual rental and royalty which amount to approximately $4million on an annual basis.

- The Water Lease provides CF(L)Co, as a corporate entity, with an exemption relating to provincially imposed taxes, charges and fees. With respect to the development, transmission and supply of hydroelectric power, CF(L)Co is exempt from any increase in taxes existing as of the July 14, 1966, and is also exempt from any liability with respect to any new or additional taxes and any new or additional charges, dues, fees, rents, etc. imposed by the Provincial Government after July 14, 1966. This exemption expires on August 31, 2016.

- The Water Lease is a statutory Lease and therefore has the force and effect of statutory law.

Power Contract Between CF(L)Co and Hydro-Quebec - May 12, 1969 ("Hydro-Quebec Power Contract")

The principle terms of this Power Contract are as follows:

- The original term of the Hydro-Quebec Power Contract expires on August 31, 2016. It will then automatically be renewed for a further term of 25 years until August 31, 2041 ("Renewal Period").

- The price of electricity during the first 40 years of this Contract was set on a downward sliding scale. It provided for five price changes during this period. The present rate ($2.5426 per MWh) will remain in effect until August 31, 2016. During the Renewal Period the rate shall remain constant at a lower rate ($2.00 per MWh).

- CF(L)Co is to make available to Hydro-Quebec Firm Capacity of approximately 4,100 MWs in the winter and 3,860 MWs in the summer, as well as whatever additional capacity can, in CF(L)Co's opinion, be made available when requested by Hydro-Quebec. In addition,

CF(L)Co shall make available such energy from the plant as Hydro-Quebec may request.

- These obligations are subject to two limitations: first, CF(L)Co's requirement to supply power and energy to Twin Falls Power Corporation Limited (225 megawatts ("MWs") until December 31, 2014 and second, the Power Contract permits CF(L)Co to withhold up to 300 MWs of power per year from the power and energy agreed to be sold to Hydro-Quebec ("the Recapture") This is to be sold by CF(L)Co only for consumption outside the Province of Quebec. CF(L)Co presently recaptures the full 300 MWs.

- During the Renewal Period (post – 2016) the amount of energy (NTD note "energy as opposed to power and energy above) that CF(L)Co will be required to sell to Hydro-Quebec under the Contract will be a set amount of energy per month ("Continuous Energy"). Currently, Hydro-Quebec has a right to all of the energy produced at the plant other than the Twinco block and the Recapture. The amount of the Continuous Energy is set at the end of the original term of the Power Contract and is based on the amount of energy delivered to Hydro – Quebec prior to the expiry of the original term.

- CF(L)Co is required to maintain in good repair and in accordance with sound utility practice, all required facilities at the Churchill Falls plant.

- If CF(L)Co should at any time, when it is not prevented by an event of force majeure, be unwilling to operate the Churchill Falls plant, then Hydro-Quebec, if it is not in default under the terms of the Contract, has the right to operate the plant for the account of CF(L)Co in accordance with sound utility practice, until such time as CF(L)Co itself resumes such operation.

Power Contract Between CF(L)Co and Newfoundland Hydro - March 9, 1998 ("NLH Power Contract")

- As noted above, CF(L)Co now recaptures 300 MWs under the Hydro-Quebec Power Contract. All of this power is sold to Newfoundland Hydro ("NLH") under this Power Contract on the same pricing terms as is applicable to the Hydro-Quebec Power Contract and for the same duration, i.e. August 31, 2041.

Guaranteed Winter Availability Contract between CF(L)Co and Hydro-Quebec - November 1, 1998 ("GWAC")

- The purpose of the GWAC is to provide for maximum availability of all eleven generating units at the Churchill Falls plant during the winter months, as this is the peak demand period for Hydro-Quebec.

- Hydro-Quebec makes payments to CF(L)Co based upon the availability of these units during the winter months. As noted earlier, the terms of the Hydro - Quebec Power Contract require CF(L)Co to make available to Hydro-Quebec on request, any additional capacity that in CF(L)Co's opinion can be made available. In essence, GWAC provides financial compensation to CF(L)Co for ensuring that additional capacity, in the amount of 682 MWs, is available during the winter.

- The GWAC terminates upon the termination of the Hydro-Quebec Power Contract.

Shareholders' Agreement between Newfoundland Hydro, Hydro-Quebec and CF(L)Co - June 18, 1999 ("Shareholders' Agreement")

- Under this Agreement, Newfoundland Hydro and Hydro-Quebec, as the shareholders of CF(L)Co, agree on certain corporate governance, operating and financial provisions related to the business and affairs of CF(L)Co. These include such things as restrictions on the transfer of shares, composition of the Board of Directors, decisions requiring the approval of both shareholders and others requiring a "special majority" of the Board of Directors, provisions relating to Twinco Power upon the expiration of the Twinco Sublease, creation of a Reserve Fund and an agreement as to a dividend policy. CF(L)Co is a party to the Agreement "to take cognizance of and to agree to comply with its terms and conditions."

- The Shareholders' Agreement expires on the earlier of date upon which either of the present shareholders (or an affiliate) no longer holds shares in CF(L)Co or August 31, 2041.

Water Management Agreement between CF(L)Co and Nalcor Energy – March 9, 2010 ("WMA")

- The Electrical Power Control Act requires that two or more persons who have been granted rights by the Province to the same body of water as a source for the production of power and who utilize, or propose to utilize, or to develop and utilize the body of water as a source for the production of power, shall enter into an agreement for the purpose of achieving the most efficient production, transmission and distribution of power.

- The WMA provides for the coordination of the use of the waters of the Churchill River in the production of power and energy by CF(L)Co on the upper Churchill River and by Nalcor on the lower Churchill River. The purpose of this Agreement is to make for the most efficient use of the waters of the Churchill River in the production of power and energy on the river, but pursuant to the Act, it can in no way adversely affect any of the existing contractual obligations which CF(L)Co has to provide power and energy i.e. Hydro-Quebec Power Contract, NLH Power Contract, GWAC and Twinco obligations.

- The WMA shall be in effect until such time as one of the parties permanently ceases to operate a production facility on the Churchill River, or the parties agree to terminate it. In the latter case, the parties must agree on a new Agreement to replace the WMA.

Electricity Imports

Department of Natural Resources
May 2012

- legislation to general idea → import limit work
- but needs to be much clearer
- needs to be written in simpler and more concise language.
- technical terms have to be marked / translated into English
- templates in evidence

↓

importance of building LIL.

ELECTRICITY IMPORTS

Introduction

In Newfoundland and Labrador, the Board of Commissioners of Public Utilities (PUB) has the authority and responsibility to ensure that proper planning occurs for meeting the short and long-term electricity requirements for the Province. Newfoundland and Labrador Hydro (NLH) has undertaken this activity for more than 40 years.

As part of their planning process to meet the impending energy needs of the province, NLH identified and reviewed a broad range of alternatives to developing indigenous resources and facilities for consideration as future sources of electricity. One of these alternatives was interconnection to regional electricity markets in order to import power to meet the provinces energy needs.

For many jurisdictions, their geographic location allows them to access surplus power from neighbouring producers and rely on them for back-up generation capability if necessary. Presently, the Island operates on an isolated island system and as such, does not have the transmission capability to import power from other jurisdictions. Consequently, there are two options for importing power to the Island:

1. A transmission interconnection from Churchill Falls to the island with the view to import electricity from Quebec.
2. A transmission interconnection from the Maritimes to the island with the view to import electricity through NS.

Electricity Imports as a Supply Alternative

1. Electricity Imports from Quebec:

Under this scenario, similar to the Muskrat Falls option, the construction of the Labrador Island Link (LIL) would be required to provide electricity imports from Quebec to the Island portion of the Province. Consequently, the transmission costs associated with delivering electricity to the Island are the same in both the Muskrat Falls scenario and the Quebec import scenario. Therefore, the cost of electricity of both scenarios will be compared at the Muskrat Falls generating station.

Supply

Over 97 percent of Quebec's electricity is generated by hydropower. Hydro-Quebec (HQ) owns 59 hydroelectric generating stations and three thermal generating stations

representing an installed capacity of 36.8 GW. Other sources of electricity include nuclear power, wind and thermal generation.

To meet their domestic commitments and long-term supply contracts outside Quebec, HQ maintains a sufficient energy reserve to offset a potential runoff deficit of 64 TWh over two consecutive years and 98 TWh over four consecutive years. It also keeps a sufficient capacity reserve to fulfill their commitments in Quebec and limit the loss-of-load expectation to one day every ten years.

Distribution System

TransÉnergie, HQ's transmission division, operates the largest electricity transmission network in North America. It acts as the independent system operator (ISO) and reliability coordinator for the Québec interconnection of the North American Electric Reliability Corporation system, and is part of the Northeast Power Coordinating Council (NPCC).

TransÉnergie's high voltage network stretches over 33,630 km through a network of 514 substations. In addition to its connections to Newfoundland and Labrador via Churchill Falls, Quebec's network is connected to neighboring provinces of Ontario, New-Brunswick and the U.S. Northeast (New York and New England) by 17 ties, with a maximum reception capacity of 10,850 MW and a maximum transmission capacity of 7,994 MW.

Overview of Quebec Interconnections

Neighboring system	**Import mode** (MW)	**Export mode** (MW)
New York	1,100	2,000
Ontario	1,945	2,705
New England	1,870	2,260
New-Brunswick	785	1,029
Newfoundland and Labrador	5,150	0

Source: Hydro-Quebec : December 31, 2011

HQ sells part of its surplus electricity to the neighboring systems under long term contracts and transactions on the New England, New York and Ontario bulk energy markets. However, most exports are for short-term spot transactions. In 2010, Quebec exported 23.3 terawatt hours of electricity, worth about $1.5 billion.

Currently, HQ has no export capability into NL in terms of physical transmission lines. However, importing from Quebec would be achieved through a reduction of the electricity delivered from Churchill Falls to HQ. In other words, in a purely hypothetical situation, if the current delivery of electricity to HQ was 3,000 MW and NL Hydro wanted to purchase 1,000 MW to serve NL demand, the delivery of power to HQ would be reduced to 2,000 MW. The 1,000 MW would then be delivered to the Island (through the LIL) from Churchill Falls.

2. Electricity Imports through Nova Scotia

Under this scenario, the construction of the Maritime Link would be required to provide electricity imports through Nova Scotia to the Island portion of the Province. Additionally, Nalcor has estimated that there would extra costs associated with delivering power directly from the Maritime Link to Soldier's Pond on the Avalon Peninsula as transmission reinforcements on the Island would be necessary. Nalcor has estimated the total transmission construction costs of this option to be roughly equivalent to the LIL (currently estimated at $1.2 billion).

Market Structure

Nova Scotia

Nova Scotia Power Incorporated (NSPI) is the utility that provides 97% of the generation, 99% of the transmission, and 95% of the distribution in the province of Nova Scotia. The remaining distribution is owned and operated by Nova Scotia's six municipal utilities. NSPI was privatized in 1992, and is now owned by Emera Inc., a publicly-traded company.

NSPI has a generating capacity of 2,368 megawatts and produces 13,000 gigawatt hours of electricity each year. It operates a variety of generating stations using various sources of energy including coal, natural gas and renewables. NSPI also purchases energy from independent power producers who generate electricity using wind, hydro, and biomass.

In 2004 a limited wholesale market was created in NS for eligible market participants (i.e. the province's six municipal utilities), which allows these customers to purchase electricity from any competitive supplier as per an Open Access Transmission Tarriff (OATT). Nova Scotia exports electricity through New Brunswick and receives backup power from that province.

New Brunswick

NB Power is an electrical utility wholly owned by the Government of New Brunswick and is composed of a holding company and 4 sub-companies: NB Power Distribution and Customer Service, NB Power Generation, NB Power Nuclear, and NB Power Transmission. The New Brunswick System Operator, not part of NB Power, is an independent market operator that administers relationships between power generators and users.

NB Power operates 14 generating stations and serves over 370,000 direct customers. The generation fleet uses a variety of energy sources, including hydro, nuclear, heavy fuel oil and coal.

NB is interconnected to neighbouring power systems in QC, New England, NS, Prince Edward Island (PEI), Northern Maine, and Eastern Maine. Aside from its interconnections with QC, all other interconnections are synchronous AC transmission lines, and they connect the Maritimes Area systems as part of the very large Eastern Interconnection of North America.

NB's Open Access Transmission Tariff (OATT) allows NS and PEI to have access to the U.S. markets due to the possibility of wheeling power through NB.

Overview of New Brunswick Interconnections

Interconnection Transfer Capability Neighboring System	Transfer Capability to New Brunswick (MW)	Transfer Capability from New Brunswick (MW)
Québec	1,000	720
New England	550*	1,000
Nova Scotia	350**	300**
Prince Edward Island	124	222
Eastern Maine	15	15

*Transfer capability from New England varies according to Maritimes Area largest contingency, load levels in Maine, status of area 345 kV MVAR resources, and the generating status of large generators near Bangor, Maine.
**Transfer capability to and from Nova Scotia is constrained by the import and export limits of the Nova Scotia electricity system.

Analysis

For its analysis of the options to import electricity from other jurisdictions, NLH used the following assumptions:

- energy was assumed to be ultimately sourced from the New York and New England markets respectively as both regions have competitive wholesale

generation markets (Nalcor did not enter into discussions with Hydro Quebec for long term electricity supply because Hydro Quebec's export alternatives are the same markets that Nalcor used as price references for imports. As a result, Nalcor used the market reference price forecast in its import option analysis);

- unrestricted access to firm transmission services were assumed to be available across intervening jurisdictions of QC and NB/NS;
- existing Open Access Transmission Tariffs for NS and NB, or for QC would be the only external transmission expenses to apply;
- each HVdc interconnection configuration would terminate at Soldiers Pond, adjacent to the Avalon load center, consistent with the LIL. As load on the island grows, increasing firm transmission capacity would be required.

The alternative to import power from other jurisdictions as the solution to meet the province's long-term energy needs raised the following considerations in phase 1 screening process:

Transmission

NLH has assumed that there are no transmission impediments to importing electricity to NL through either scenarios. With respect to the importing from QC scenario, this is essentially the case. As mentioned, the 'delivery' of power would be accommodated through the existing infrastructure that connects Churchill Falls with the HQ system.

However, in reality, there are a number of transmission issues with importing electricity through NS to NL. The NS Interface with NB is made up of a single 345 kV transmission line, and two 138 kV transmission lines. If the 345 kV transmission is out of service, the two 138 kV lines can support 100 MW of flow from NB to NS. Consequently, there would not be available transmission capacity from NB to NS to provide import capacity to deliver large scale (500+ MW) reserves to the Island as import capacity from NB into NS is currently limited to 350 MW. The extent of transmission system reinforcements that may be required across NS and NB is unknown.

The New England interface connecting New England and NB is the only synchronous connection between the Maritimes Area and the Eastern Interconnection. The import total transfer capability on this connection is 550 MW, of which 300 MW is designated as firm. The remaining 250 MW is dependant on the status of NE facilities and the largest generation contingency in the Maritimes Area and is designated as conditional firm.

Additionally, in the New England and New York markets, there are currently no long-term physical transmission rights (beyond 1 to 2 years). NL would be unable to secure long-term transmission rights in these markets which would introduce considerable risk with respect to securing supply to meet the province's energy needs.

As well, to allow imports from the Maritimes, the Martime Link would be likely be required to reverse power flow direction on demand to compensate for generation variability on the Island. While this is technically possible, neither the NS nor NL systems have the ability to absorb these swings; consequently, outages would be likely.

Supply

There are also significant supply issues associated with importing electricity. For example, both NS and NB are winter peaking systems; therefore, surplus capacity in those jurisdictions is not expected to be available to import into NL.

Nalcor has estimated that beyond 2015, both New England and New York are facing potentially significant plant retirements due to the age of the generation fleet and because a significant proportion of the baseload generators in the region are carbon fueled (coal and gas in particular).

In New York 60 percent of installed generation is pre 1980's generation[1] and 53 percent of capacity is oil or coal fired.[2] Resulting from more stringent Environmental Protection Agency (EPA) regulations, the New York Independent System Operator predicts that almost 24,000 MW of generation capacity will be impacted and certain older facilities may be no longer competitive and forced to close.

Similarly, in New England, coal and oil generation comprise over 9,500 MW and the New England system operator estimates that between 5,800 MW and 8,700 MW will be retired or de-rated as a result of more stringent EPA rules. Such plant retirements and/or de-ratings in the region have implications for the availability of supply.

Price

Natural gas-fired generation is typically the marginal supply source and price setter in both the New York and New England wholesale generation markets and Nalcor used the market reference price forecast when analyzing the import options.

However, as a result of the strong correlation between electricity market clearing prices and natural gas prices, these wholesale market prices are exposed to gas price volatility. In addition to gas price volatility, many other local variables affect the short term clearing prices in these markets, including weather conditions impacting peak demand, unplanned generation or transmission outages, and transmission congestion.

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[1] New York Independent System Operator, *Power Trends 2011 Presentation*, 2011 http://www.nyiso.com/public/webdocs/newsroom/power_trends/Power_Trends_2011_Presentation.pdf

[2] Ibid.

Conclusion

The two scenarios analyzed for importing electricity from other jurisdictions to the Island are:

1. A transmission interconnection from Churchill Falls to the island with the view to import electricity from Quebec.
2. A transmission interconnection from the Maritimes to the island with the view to import electricity through NS.

Both scenarios would require significant transmission construction to deliver the electricity to the Island (LIL or Maritime Link) and Nalcor has determined that both have significant risk with respect to ensuring the secure, stable, long-term delivery of power to the Island.

Nalcor has identified those risks as being related to transmission impediments, security of long-term supply, and price volatility and as a result, the reliance on electricity imports as a long-term supply option for the island was not considered further following its initial screening.

Gull Island Hydroelectric Project

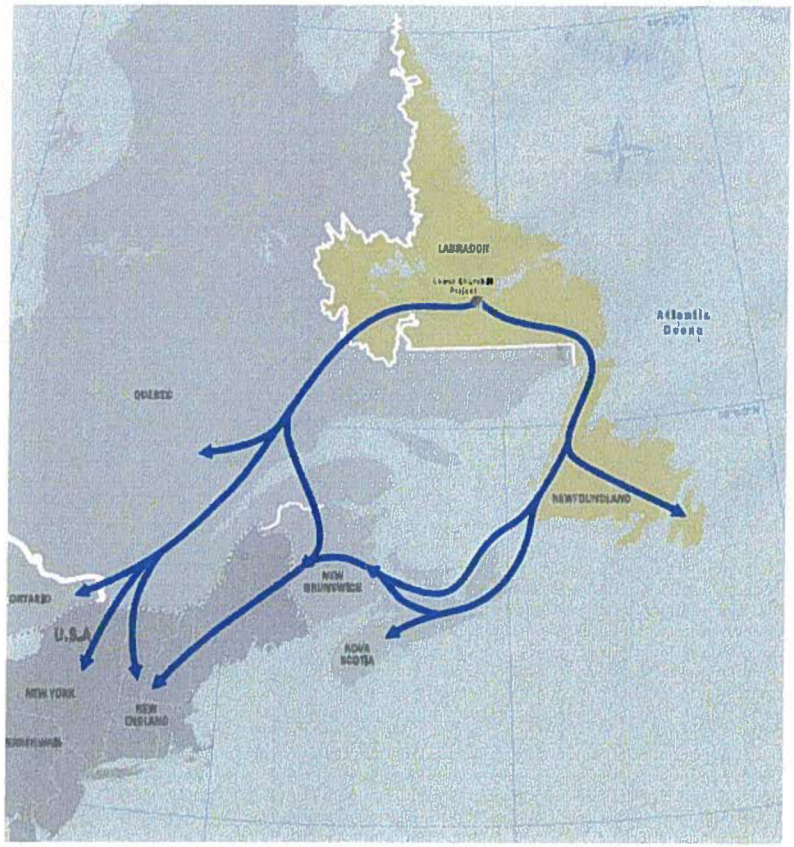
Department of Natural Resources

June 2012

Introduction

Following the development of the 5,428 megawatt (MW) Upper Churchill hydroelectric facility and associated transmission lines in Labrador in the late 1960s, the Lower Churchill hydroelectric opportunities (including the Gull Island and Muskrat Falls projects) have been considered for development. In particular the past fifteen years has been a period with numerous attempts by Newfoundland and Labrador (along with various other parties) to find a suitable project configuration and commercial terms to facilitate development of the Lower Churchill hydroelectric potential. However, to date, no Lower Churchill project opportunity has been successful although the most recent project configuration of the Muskrat Falls generation project with transmission links to Newfoundland and Nova Scotia has been progressing. While success of Lower Churchill development has been elusive, the previous work has allowed Newfoundland and Labrador to gain extensive insight and understanding of the Lower Churchill development opportunity.

Figure 1 – Lower Churchill Potential Markets & Routes

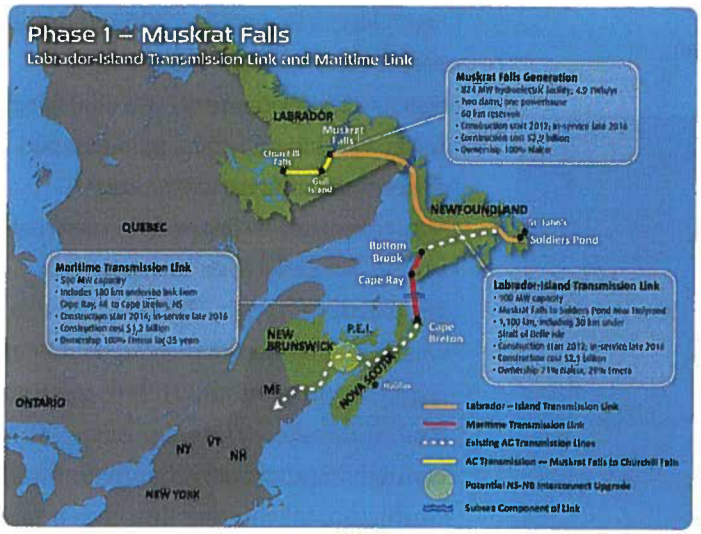


Source: Newfoundland and Labrador Energy Plan, Sept 2007

In late 2006, Newfoundland and Labrador Hydro (NLH) filed the Gull Island and Muskrat Falls generation projects for environmental assessment both federally and provincially. Following an extensive review process, the Joint Review Panel (JRP mandated by the federal and provincial ministers to assess the environmental effects of the proposed projects) concluded its report in August 2011. Following the federal and provincial respective consideration of the JRP report, both levels of government released the generation projects from environmental assessment in March 2012.

In January 2008, NLH announced a Memorandum of Understanding (MOU) with Emera Inc. and Nova Scotia Power Inc. to explore the possibility of bringing energy from the Lower Churchill Project to the Maritimes and New England markets. Following collaborative analysis and discussions, the Governments of Newfoundland and Labrador and Nova Scotia, as well as Nalcor Energy and Emera Inc., jointly announced the signing of a term sheet in November 2010 to proceed with commercial negotiations and further detailed study of a

Figure 2 – Lower Churchill / Muskrat Falls Project



Source: Nalcor Energy

Muskrat Falls generation and Labrador-Island Link/Maritime Link transmission project configuration that would facilitate delivery of Muskrat Falls power to the Island of Newfoundland, Nova Scotia and into New Brunswick and northeast U.S. electricity markets. Negotiations and project analysis are advancing with consideration of a project sanction decision for Newfoundland and Labrador anticipated later in 2012.

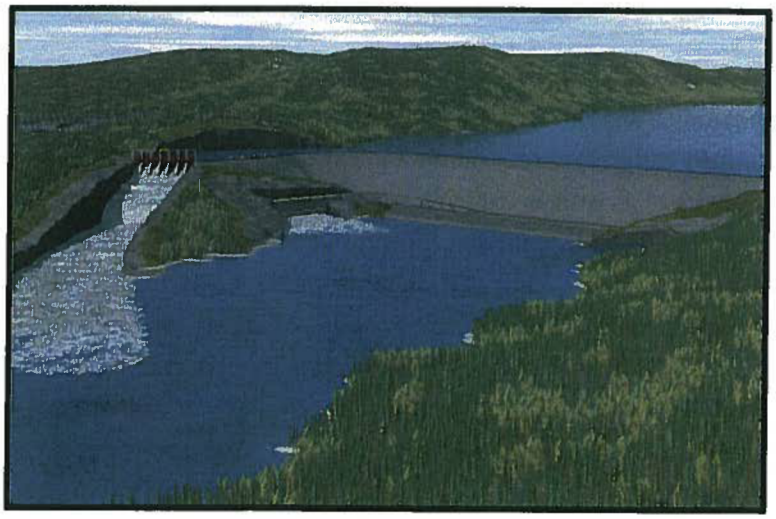
The intent of this paper is to discuss the Gull Island hydroelectric project and consider the project's market opportunities and challenges.

Gull Island Project Overview

Gull Island Generation Facilities

The Gull Island hydroelectric project is located on the Churchill River in Labrador, 225 km downstream from Churchill Falls and approximately 300 km from the Labrador/Québec border. The Gull Island hydroelectric opportunity would consist of the development of an approximate 2,250 megawatt (MW) generation facility (approximately 2.7 times the 824 MW capacity of Muskrat Falls) and associated transmission infrastructure required to deliver power to potential markets in Newfoundland and Labrador as well as externally into the Maritimes, Quebec, Ontario and the northeast United States. The configuration of transmission would be contingent on the optimal market opportunities as well as access to existing grid systems compared to new build construction of transmission assets. Annual energy output from Gull Island is

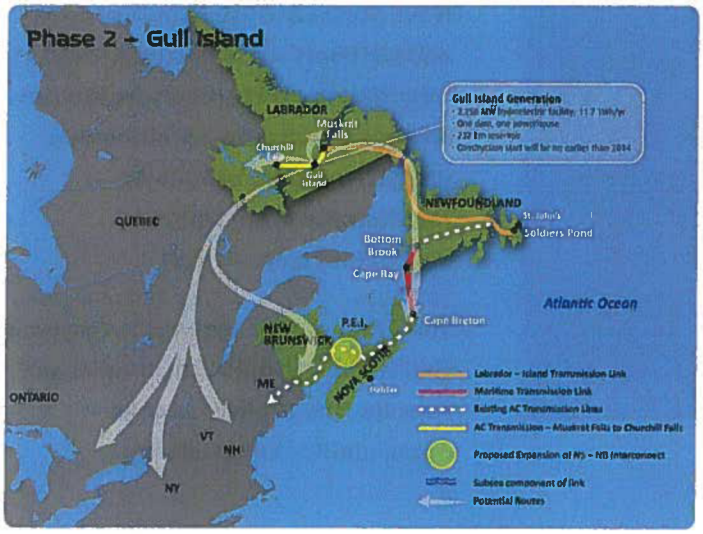
Figure 3 – Gull Island Project Concept



Source: Nalcor Energy

estimated to be in the range of 11.7 terawatt-hours (TWh) representing nearly 2.4 times the 4.9 TWh annual energy output of Muskrats Falls.

Figure 4 – Lower Churchill / Gull Island Option



Source: Nalcor Energy

From NLH's November 2006 generation project environment assessment registration document, the Gull Island facility would include a spillway and powerhouse along with a dam (approximately 470m wide) constructed on the Churchill River to create an upstream reservoir. The rock fill dam would be located at the head of Grizzle Rapids, approximately 1.2km upstream from Gull Lake. Water would be routed through an approach channel on the south bank of the river into the intake and spillway structures. The 200m long, 53m wide powerhouse would be constructed at the foot of the dam and would be supplied water through underground penstocks from the intake.

Currently, the development of Gull Island is planned to follow the Muskrat Falls development although no commercial in-service date is targeted presently for Gull Island with a construction period estimated to require approximately six years. If Muskrat Falls is sanctioned and following project in-service with secured markets, Nalcor Energy expects to be in a position to further consider the development of Gull Island, which could be used to supply provincial industrial developments as well as sell surplus power into export markets.

Gull Island Considerations

The Gull Island hydroelectric project represents a significant capacity at 2,250 MW and would require consideration of various market opportunities within Newfoundland and Labrador (including industrial sector demand and potential growth in Labrador) as well as externally in export markets. At more than twice the output of Muskrat Falls and in the absence of significant load growth beyond current forecasts within Newfoundland and Labrador, Gull Island would require transmission access to external markets that would be significantly greater than that contemplated for Muskrat Falls. A Gull Island development scenario could require in the range of 1,500 to 2,000 MW of transmission capacity to access external markets in the initial decades following in-service whereas Muskrat Falls, by comparison, will require external transmission capacity access in the range of 300 to 500 MW initially and gradually reducing as Newfoundland and Labrador load growth increases.

A key issue in considering to develop Gull Island is whether Newfoundland and Labrador electricity

demand will be such to require the larger capacity development and/or whether sufficient transmission capacity is available or could be built economically to facilitate access to export markets until domestic load growth is such Newfoundland and Labrador to require the entire output of Gull Island.

Newfoundland and Labrador Electricity Market Outlook

Provincial Load Forecast

NLH's current 20 year Long Term Planning Load Forecast (PLF) indicates an overall period of load growth with the Island interconnected system forecast to grow by 1.3 percent annually, the Labrador interconnected system to grow by 1.1 percent annually, the Island rural isolated systems to decline by 0.2 percent annually, and Labrador rural isolated systems to increase by 1.5 percent annually. Currently, non-coincident provincial demand (combined peak demand from all sources) is about 2,000 MW with associated energy requirements of 10 TWh per year. The current PLF indicates growth to nearly 2,400 MW of peak demand and 12.8 TWh of annual energy by 2029. Overall, total provincial load is forecast to increase by 1.3 percent annually (with the majority of increase in the first half of the forecast period) driven primarily by growth on the Island interconnected system which represents about 75 percent of the total provincial load.

Currently, NLH is forecasting a capacity deficit on the Island interconnected system by 2015 meaning there will not be enough generating capacity to meet the peak demand power requirement. Further, NLH is forecasting an energy deficit on the Island interconnected system by 2020. As such, additional new supply will be required in that timeframe to meet load growth and maintain system reliability standards.

In addition to the PLF outlook with anticipated capacity and energy deficits for the Island interconnected system, Newfoundland and Labrador has be seeking a supply replacement alternative for the 490 MW Holyrood thermal generating plant in order to avoid environmental mitigation investments at the aging facility, remove the greenhouse gas emitter from the provincial portfolio and remove a significant fuel oil cost from customer electricity rates. These combined requirements have helped set the stage for a review and evaluation of alternate supply options by Nalcor Energy and NLH. That review has resulted in the current Muskrat Falls project configuration being put forward as the least cost supply option with sufficient generating capacity (at 824 MW) to meet Island interconnected requirements and surplus output that can access and be sold into export markets (via the proposed Maritime route) until it may be required to meet future Newfoundland and Labrador load growth.

Opportunity for Industrial Load Growth in Labrador

While NLH's current PLF outlook anticipates load growth for the Labrador interconnected system and Labrador rural isolated systems, the PLF has not yet incorporated the various new and expansion mining proposals for Labrador being put forward by proponents as a result of strong commodity prices and renewed mineral exploration in western Labrador. The proponents have indicated that these mining opportunities would require adequate electricity supply at competitive rates to proceed.

Current mining operations in Labrador have a combined electrical power requirement of nearly 300 MW and include the Iron Ore Company of Canada (IOC) and Wabush Mines iron ore operations in Labrador West. As well, there are mining operations near Nain at Vale's Voisey's Bay project and the Labrador Iron Mines project in the Menihek region.

There are various new Labrador mining proposals under consideration by proponents including:

- Projects currently under development (IOC's Concentrate Expansion Program Phase II and Tata Steel's Direct Shipping Ore project) which proponents indicate could require 40 to 50 MW of power.
- Projects undergoing feasibility study (Alderon Kami project, Grand River Iron Sands project, IOC's CEP Phase III, additional IOC expansion, Tata Steel's LabMag project) which proponents indicate could require 600 to 900 MW of power.
- Longer term developments in pre-feasibility study (Alderon Kami project expansion, Julienne Lake project, Grand River Iron Sands Phase II, additional IOC expansion) which proponents indicate could require 250 to 350 MW of power.

Potential growth of industrial mining opportunities in Labrador could create significant generation requirements in Labrador although many of these mining opportunities are currently in either feasibility or pre-feasibility stages of study and do not yet represent firm power requirements. To facilitate the provision of power for additional mining developments that do proceed forward will require coordinated planning between Nalcor Energy/NLH and the mining proponents.

Implications for Gull Island Supply Option

An important consideration to develop Gull Island to meet domestic load requirements is in regard of the 2,250 MW capacity size and whether it can be fully utilized domestically. If not, then access to external markets would be required to ensure that all capacity and energy output is monetized and full value realized.

The latest PLF from NLH indicates that a new supply option is required to meet projected load growth on the Island interconnected system. As well, a sufficient renewable supply option is preferred to facilitate the retirement of Holyrood. This would collectively put the power requirement in approximately the 500 MW range initially and increase with load growth. As well, this requirement would be variable through the year given the significant seasonal load swings with the space heating requirement in winter. As such, this requirement alone would not be enough to consume the entire Gull Island output and other market opportunities (whether domestic or export) would be required.

A current unknown for electrical system planners exists with regard to the potential for Labrador industrial growth from the mining sector. The potential growth at the high end of new mining opportunities could be enough to consume all available surplus power from Churchill Falls recall and Muskrat Falls with a need for additional power supply. The primary issue here, however, is the ability to effectively plan for industrial load growth requires a commitment from new industrial consumers before significant investments would be made in new generation and transmission infrastructure. Currently,

many of these Labrador mining opportunities are at feasibility and pre-feasibility planning stages and, as such, may not be in a position to give NLH and Nalcor Energy the commitment required that would facilitate significant new electricity supply investments. That said, if the new mining proposals move beyond feasibility stages towards development then electricity supply options are available for system planners including surplus Churchill Falls recall power, surplus Muskrat Falls power, imports (if required as a shorter term bridging supply option), smaller scale hydroelectric and wind supply options, and Gull Island (as a longer term option).

If Nalcor Energy and/or NLH were to proceed to develop Gull Island and the new Labrador mining industrial load did not materialize, whether due to a downturn in commodity markets or other investor decision, then the result could be a significant over-build of the electrical system that could be stranded if access to external markets is not available.

Taking into account the current NLH PLF only, the transmission capacity required to export surplus power from Gull Island could be in the range of 1,500 to 2,000 MW. Even in a more optimistic case of an additional 1,200 MW of new mining industrial load by 2020 in Labrador would still result in a need for approximately 300 to 800 MW of available export capacity in the initial decades following Gull Island in-service.

Export Market Opportunities

Export Markets

External market opportunities for the sale of Lower Churchill power have been a key consideration for project configurations considered to date particularly as a Lower Churchill project would likely be beyond the load growth needs of Newfoundland and Labrador for the foreseeable future. While surplus Muskrat Falls power could be consumed by new industrial mining proposals and associated power requirements being contemplated, the same could not necessarily be said for Gull Island. As noted above, Gull Island would likely still require external market access in order to monetize surplus power although the magnitude of external transmission system access requirements would be conditional on the load requirements in Labrador and on the Island of Newfoundland.

Markets that have been considered as opportunities for export sales of Lower Churchill power include the Maritimes (Nova Scotia and New Brunswick), Québec, Ontario and the northeast United States. All of these markets represent various challenges but share a common consideration of requiring viable transmission access for Lower Churchill power. Since the implementation of Federal Energy Regulatory Commission (FERC) open transmission access policies and competitive markets for electricity, the U.S. has become an open marketplace for electricity sales whereby supply (that has market transmission access) can be bid and economically dispatched in regional spot markets. Similarly, while the model of competitive markets has been slower to materialize in Canada, the adoption of open transmission access policies has occurred in many Canadian jurisdictions with the intent to provide fair access to market participants as well as meet FERC requirements for those Canadian electricity suppliers selling power in U.S. markets.

As shown earlier in Figure 1 of this report, Lower Churchill power, in order to access external markets, would require access through one or both primary routing corridor options including Québec and/or the Maritimes. Transmission access through Québec could facilitate access to the Québec market and subsequently to Ontario, the northeast U.S. and the Maritimes (all directly from interconnections with Québec). Similarly, transmission access through the Maritimes could allow for access to the Maritime markets (Nova Scotia and New Brunswick) and subsequently to New England, Québec and further on to New York and Ontario (via New York or Québec). A key consideration then becomes, could the Gull Island project access external markets via one or both of these route options?

Hydro-Québec Transmission System Access

The Hydro-Québec TransÉnergie (HQT) transmission system is one of the most extensive in North America comprising 514 substations and more than 33,630 km of lines at various voltages. HQT has multiple interconnections with neighbouring systems in Canadian provinces and various northeast U.S. states. Table 1 outlines the neighbouring systems and import/export total capabilities. As can be seen from the HQT intertie export capabilities in Table 1, significant intertie capacities currently exist to facilitate power exports out of HQT's system, however, booking these capacities presents its own challenges even in an open access system.

Table 1 – Hydro-Québec TransÉnergie Interconnections

System	Import Capability to Québec (MW)	Export Capability from Québec (MW)
New York	1,100	2,000
New England	1,870	2,260
Ontario	1,945	2,705
New Brunswick	785	1,029
Newfoundland & Labrador	5,150	0

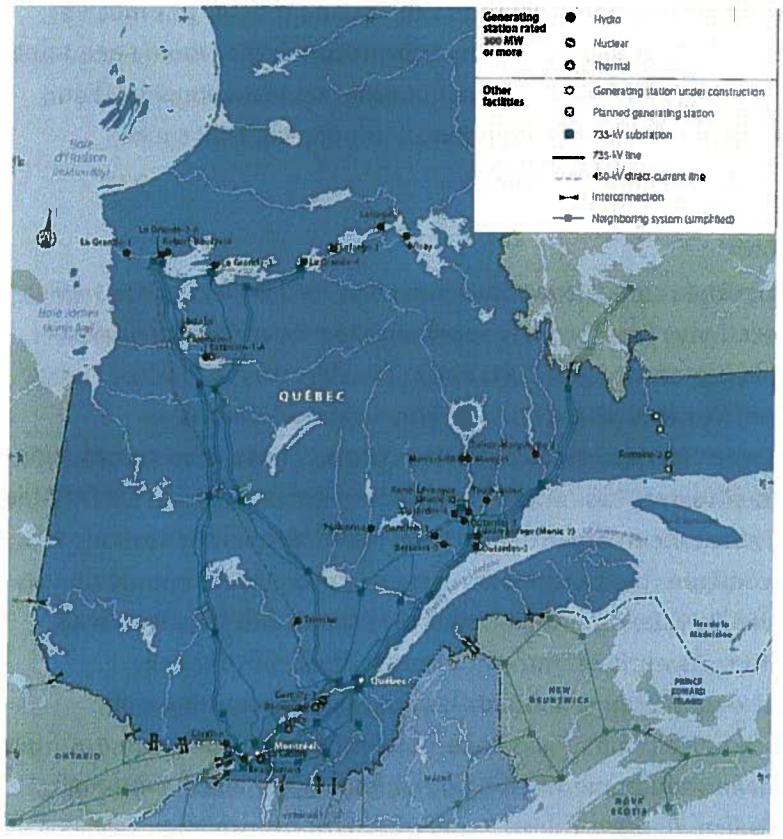
Source: Hydro-Québec TransÉnergie

Hydro-Québec has an open access transmission model for its system (implemented in 1997) and has an Open Access Transmission Tariff (OATT) outlining its service access terms and applicable tariffs.

Since January 19, 2006, NLH has made four transmission service applications to HQT in accordance with its OATT. These applications (two related to Lower Churchill development and two related to the NLH's Upper Churchill recall block) led to various complaints by NLH with the Régie de l'énergie (Québec's energy regulator) on three of the applications due to disagreement with HQT on interpretation and application of its OATT related to the service requests. The fourth application for 265 MW of transmission capacity relating to deliveries of Upper Churchill recall power was accepted as complete by HQT and transmission service under the HQT OATT is being provided to NLH.

As noted above, there have been two applications to date by NLH related to potential Lower Churchill development.

Figure 5 – Hydro-Québec TransÉnergie Transmission System



Source: Hydro-Québec TransÉnergie

Application #1 - In January 2006, NLH made an application for transmission service to HQT for up to 2,824 MW of capacity into Québec and to the Ontario, New Brunswick, New England and New York markets for deliveries from the Lower Churchill project for 30 years starting in 2015. This application was accepted and HQT undertook a system impacts study. NLH disagreed with HQT's interpretation and application of its OATT in the preparation of this study and NLH filed complaints with the Régie de l'énergie. This application has now been terminated by HQT.

Application #2 - In February 2007, NLH made a second application for 724 MW of transmission capacity relating to deliveries from the Lower Churchill to complement the first application (outlined above) and to increase deliveries into New Brunswick and New England. This application was initially accepted although HQT subsequently decided that NLH had made a substantial change to its original request and determined it was a new request resulting in a loss of priority to NLH. NLH protested HQT's decision and HQT reinstated the priority although NLH proceeded with a complaint to the Régie de l'énergie for regulatory interpretation as HQT refused to acknowledge its original misapplication of the OATT. This application has now been terminated by HQT, as it was linked to the larger application #1 above.

With regard to NLH's complaints filed with the Régie de l'énergie arguing a HQT breech of the principles of open access and non-discrimination under its OATT, the Régie ultimately ruled in favour of HQT and dismissed the arguments put forth by NLH/Nalcor Energy. Nalcor Energy (along with the Government of Newfoundland and Labrador) have indicated that HQT's application of its OATT and the subsequent Régie rulings are in contravention of market frameworks supporting competition including FERC open access (the model applied in Québec) rules designed to eliminate discrimination in the provision of grid access.

A lesson for Newfoundland and Labrador from these experiences with HQT and the Régie de l'énergie is that, while NLH has successfully received transmission rights to 265 MW of capacity on the HQT system,

anything more substantial including capacity necessary to support power flows from Lower Churchill (whether from Muskrat Falls and/or Gull Island) through Québec would not be easily secured. In the case of the significant capacity reservation requirements related to Gull Island (possibly as much as 1,500 to 2,000 MW in the initial decades following in-service), the transmission rights would need to be non-discriminatory and booked to ensure long term market access in order that Newfoundland and Labrador could realize full market value. Based on recent experience, it is not clear that such transmission access rights on the HQT system would be available.

Maritime Route Transmission Option

Alternatively, transmission through a Maritime route (Nova Scotia and New Brunswick) option, similar to that proposed for the Muskrat Fall project, may represent an opportunity to move Gull Island power into external markets. This is the current project configuration under consideration by Nalcor Energy and Emera to include the Labrador-Island (Newfoundland) transmission link and a Maritime transmission link (primarily subsea) between Newfoundland and Nova Scotia. These new transmission assets will facilitate transferring all of the Muskrat Falls output to Newfoundland and up to 500 MW into Nova Scotia. A consideration under this scenario in order to build Gull Island, instead of Muskrat Falls, would be the requirement to resize/reconfigure the transmission assets in order to accommodate the increased loads. As well, upgrades would likely be required on the Nova Scotia and New Brunswick transmission systems to accommodate the power flows into and through these jurisdictions. Alternatively, a Gull Island project could keep the same Labrador-Island Link and Maritime Link configuration as being proposed for Muskrat Falls and flow surplus power through Quebec and/or utilize in Labrador for new industrial mining power requirements (should that load materialize). Although, recent difficulties experienced by NLH/Nalcor Energy with HQT application for transmission access would need to be considered.

Nova Scotia Power Inc. owns the 5,200 km of bulk transmission system across the province of Nova Scotia which is operated by the Nova Scotia Power System Operator (NSPSO). Given the current Muskrat Falls configuration scenario, the Nova Scotia transmission system would be capable of moving in the range of 500 MW which could represent a significant constraint if a Gull Island export project scenario is considered. The Nova Scotia system would likely require significant system upgrades to handle a 1,500 to 2,000 MW Gull Island export scenario. A further constraint would be the intertie capacity between Nova Scotia and the New Brunswick transmission system. There are three interties (one 345 kV and two 138 kV lines) between Nova Scotia and New Brunswick with a combined total export capability of 350 MW which falls short of what Gull Island would require to access the New Brunswick grid, not to mention that some or all of this capacity may not be available for booking. If transmission access is achieved through Nova Scotia, New Brunswick's power transfer capability with neighbouring systems includes nearly 800 MW into Quebec, 1,000 MW into ISO New England as well as a 100 MW into northern Maine and 15 MW into eastern Maine, however, the transmission constraints through Nova Scotia for a Gull Island project could represent an economic challenge for Gull Island.

Although system impacts studies have not been undertaken for a Gull Island scenario of 1,500 to 2,000 MW of transmission access through Nova Scotia and New Brunswick, it is likely that new build transmission infrastructure would be required to handle such a power requirement (including upgraded

intertie capacity with Nova Scotia and New Brunswick and its neighbouring systems). The costs associated with these transmission additions and upgrades would likely be significant and could be directly assigned to Nalcor Energy (and any partners) as the applicant for service with potentially minimal or no benefit to other Nova Scotia customers. Alternatively, a dedicated subsea transmission line could be constructed from Nova Scotia to New England although costs would likely be significant and again directly assigned to Nalcor Energy and any project partners. The Transmission and System Operator Options for Nova Scotia report completed in December 2009 by SNC-Lavalin included a cost estimate of $2-$3 billion for a subsea line between Nova Scotia and New England.

It appears that a Gull Island project with significant surplus capacity to sell in external markets (and following a Maritime route) would probably look to sell power in Nova Scotia (and possibly New Brunswick) in order to monetize power and avoid much of the transmission upgrades that would be necessary to move larger blocks of power into New England and any subsequent markets. Nova Scotia could be an opportunity for power sales given it has approximately 2,600 MW of generating capacity of which the majority includes thermal generation sources. The Province may be willing to reduce its reliance on fossil fuel thermal power sources and add more renewable, clean power alternatives.

Currently, a Maritime route option, as it could be applied to a Gull Island generation development, represents several significant unknowns including the costs associated with any transmission system upgrades, the degree to which the Gull Island developer would be responsible for paying any additional transmission upgrade costs and associated tariffs, the interest of the Maritime market in purchasing any Gull Island power, and whether Gull Island power could be flowed partially through Québec and a Maritime route as one project proposal in order to access external markets. To adequately address these questions, system impacts studies and further consideration would be required.

Conclusions

Based on this review, the immediate opportunity for Gull Island development is not clear. Gull Island would require additional capital investments in generation and transmission infrastructure compared to the currently proposed Muskrat Falls project configurations. As well, the required access to external markets may encounter challenges given the transmission capacities required to move large blocks of Gull Island power and the associated costs that may be incurred. In reviewing whether to proceed with a Gull Island development option, it is important to consider that:

- Since development of the Upper Churchill project, there have been various Lower Churchill project configurations studied and commercial negotiations attempted although none have resulted in a successful project development to date. A significant amount of knowledge and insight has been attained by Newfoundland and Labrador through its attempts to develop the project over that time.
- A Gull Island project represents a significant hydroelectric resource development potential at 2,250 MW of capacity and estimated annual energy output of 11.7 TWh.
- Domestic Newfoundland and Labrador load growth, as currently forecast by the NLH PLF, would not

be sufficient to fully utilize all of Gull Island power output. As such, additional markets/customers would be required to support the development and required investment.

- Potential growth of industrial mining opportunities could create significant load requirements in Labrador, however, the majority of these opportunities are currently in either feasibility or pre-feasibility stages of study. These do not represent the firm power requirements that would be needed to plan the significant investments in the Gull Island hydroelectric potential. If this demand materializes then supply options would include surplus Churchill Falls recall power, surplus Muskrat Falls power, imports (if required as a shorter term bridge supply option), smaller scale hydroelectric and wind supply options, and Gull Island (as a longer term option).

- If Nalcor Energy and/or NLH were to proceed to develop Gull Island and the new Labrador mining industrial load did not materialize, whether due to a downturn in commodity markets or other investor decision, then the result would be a significant over-build on the electrical system that could be stranded if access to external markets is not available. Even a scenario with significant new power requirements for Labrador mining projects, access to external markets could still be required in order to monetize surplus power.

- While NLH has successfully received transmission rights to 265 MW of capacity on the HQT system, anything more substantial including capacity necessary to support power flows from Gull Island and/or Muskrat Falls through Québec would not be easily secured. In the case of the significant capacity reservation requirements related to Gull Island (possibly as much as 1,500 to 2,000 MW in the initial decade), the transmission rights would need to be non-discriminatory and booked to ensure long term market access in order that Newfoundland and Labrador could realize full market value. Based on recent experience, it is not clear that such transmission access rights on the HQT system would be available.

- A Maritime route option, as it could be applied to a Gull Island generation development, represents several significant unknowns including the costs associated with any transmission system upgrades, the degree to which the Gull Island developer would be responsible for paying any additional transmission upgrade costs and associated tariffs, the interest of the Maritime market in purchasing any Gull Island power, and whether Gull Island power could be flowed partially through Québec and a Maritime route as one project proposal in order to access external markets. To adequately address these questions, system impacts studies and further consideration would be required.

Currently, the Government of Newfoundland and Labrador and Nalcor Energy (along with the Government of Nova Scotia and Emera Inc.) are considering the Muskrat Falls project configuration with interconnection from Labrador to Newfoundland (to provide power to Island customers and displace the Holyrood thermal facility) and an additional interconnection with Nova Scotia to provide external market access for surplus generation. Once Muskrat Falls is operational and markets are secured, Nalcor Energy expects to consider options for Gull Island development and build on the experience and knowledge gained from the development of Muskrat Falls and the previous attempts to develop the Lower Churchill's hydroelectric potential.