CENTRE HELIOS

RESEARCH, ANALYSIS AND EXPERTISE IN ENERGY POLICY

Comments on Proponent's Response to the Panel's Information Request of March 21, 2011

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April 13, 2011

Responses of April 1, 2011

As I emphasized in my Initial Comments (February 28, 2011), timely access to complete information is a prerequisite for any environmental assessment process. In those Comments, I identified serious failings in this regard with respect to the information provided by the Proponent, in particular with respect to the scenario where only the Muskrat Falls project might be built.

Fortunately, the Panel recognized this failing. In its letter of March 21, 2011, it requested significant new information from the Proponent, who responded on April 1. Unfortunately, the Proponent's response failed to provide much of the information requested by the Panel. In this first section, I summarize the Panel's questions, describe the Proponent's written responses and comment on their adequacy.

Part A: Financial Benefits, Cash Flow and ROE for MF and GI

Financial Benefits: provide charts similar to Slide 21 of CEAR #758 for MF and GI, separately.

Provided, without data or comment, in Figures 5 and 6. (Note: there are no Figures 3 and 4 in the document)

Cash Flow:

1. Provide a similar chart showing net cash flow only for MF and GI, separately.
   Provided, without data or comment, in Figures 7 and 8.
2. Provide the assumptions used in #1
   a. amount of energy sold, markets and sales price received,
   Provided in Figures 1 and 2. No reference to earlier evidence for market prices used, no explanation of "weighted average market price" used, nor justification for divergences.
   b. amount of debt vs. Equity
   Provided on page 5; no explanation for differences (70:30 for GI; 59:41 for MF)

3. Provide resulting return on equity for MF and GI
    Provided on page 11, without comment on source.
4. Repeat #1-3 for GI, based on specified variants (80% energy sales, +10% capital cost, -15% price)
   Charts provided, with resulting IRR. Underlying data not provided. No comment on result, except for argument that the scenario requested is not plausible.
5. Repeat #1-3 for MF, based on specified variants (+10% capital cost and no export sales; +10% capital cost and 50% export sales)
   Charts provided, with resulting IRR. Underlying data not provided. No comment on result, except for argument that the scenario requested is not plausible.

Part B: Financial Analysis of Alternative Generaiton Sources on Island

<u>Scenario 1 NLH Systems Plan:</u> Provide financial analysis for new generation on isolated Island system, showing financial benefits, cash flow and ROE to 2041 that can be compared with MF scenario.

Not provided. Response (pp. 14-16) simply consists of a justification of the non-response, consisting of description of metric (CPW) used by traditional utility planning to compare scenarios.

<u>Scenario 2 – Aggressive CDM:</u> Estimate potential for increased CDM on Island, and redo financial analysis of Scenario 1, taking into account maximum estimated CDM potential

1. Provide summary of current status of CDM programs of NLH and NP, including
   a. most recent plans and PUB decisions, and
      Provided.
   b. current program budget ($/yr) and objectives (MW and MWh)
      Provided.
2.
   a. Specify amounts (MWh and MW) for space heating
      Provided.
   b. Results of CDM programs to date
      Alluded to ("To date, the utilities have seen lower than predicted initial savings, but with positive signs of growth."), but not provided. See below for analysis of NLH/NP CDM programs.
3. Based on Marbek study and avoided cost based on Holyrood operating costs, specify economic CDM potential by 2014, 2019, 2024 and 2029.
   Not provided.
4. Assuming CDM and smart grid investment levels of 1,5%, 3% and 5% of annual electric revenues, what portion of CDM potential identified in #3 could be expected to be realized by 2014, 2019, 2024 and 2029.

Not provided.

How would this affect Island load forecasts and new generation requirements?

Not provided.

Scenario 3 – Incorporate Potential for Small Hydro, Tidal and Wind Energy :

Estimate potential for small scale renewable energy on Island

Redo financial analysis of scenario 1, incorporating this in supply mix

1. As background, provide a summary of current status of IRP activities of NLH and NP.

   Response states only that PUB chose not to impose IRP in 2006,deferring to forthcoming provincial Energy Plan. No indication that either NLH or NP has moved forward in any way toward an IRP process, as they have not been obliged to do so by the PUB.
2. With investment equal to Holyrood operating costs, how much small scale renewable energy generation could potentially be integrated into an isolated Island grid by 2014, 2019, 2024, 2029?

   Not provided. The response simply refers to the amounts in the Generation Planning Issues 2010 Update *(already in the possession of the Panel).*
3. What order of magnitude investment would be required in system upgrades to do so?

   Order of magnitude system upgrade costs are provided only for a scenario in which Holyrood is completely replaced by small scale renewable generation. No estimates are provided for the scenarios requested by the Panel, in which small scale renewables are added progressively.

a. What would be technical and economic feasibility of booking [sic] a portion of existing hydro capacity (currently base loaded) as dispatchable power to even out the impact of less reliable renewables?

   Response identifies lack of interseasonal storage as a major impediment to this strategy.

b. Is there a potential to augment dispatchable power at existing hydro sites using wind pumps?

   No response provided.

Additional responses on cash flows

My efforts to make sense of the various financial information provided by the Proponent have not been entirely successful. Despite the supplemental information provided this morning consisting of cash flow data,[1] some areas of confusion still remain. The remaining time before the 4pm deadline simply does not allow a full presentation of my findings.

[1] I refer only to page 5, Cash Flow Detail for Figure 8 (of the April 1 Response) (henceforth “Fig. 8 Data”).

Integrated Resource Planning

The excerpt from PUB Order P.U. 8 (2007) on p. 29 of the Response clearly indicates that the Board considers integrated resource planning (IRP) to be "an important planning tool" and that it "would enhance the information available to the Board and other parties regarding future generation and supply options in the Province." However, given the upcoming provincial Energy Plan, the Board chose not to order the commencement of an IRP process at that time.

According to the Proponent's comments this morning, there has been no progress whatsoever since that time (four years ago) with respect to integrated resource planning, either from the PUB or from the regulated utilities. This is extremely unfortunate, because IRP is precisely the tool needed to properly compare the economic and environmental implications of alternate solutions to providing reliable electric power –the very question that is at the heart of addressing Justification and Alternatives in an environmental assessment process.

For this reason, IRP was at the heart of the justification review of the Great Whale Hydroelectric Project in the early 1990s. I earlier submitted excerpts from the study we prepared on this subject for the Review Panels.[2] I would urge the Panel to consult the full study; unfortunately, I do not have a copy that I can submit before 4 pm today, though I would be pleased to provide it once I return to Montreal. Since it was prepared for a federal environmental assessment (EARP) process, I would encourage the Panel to take cognizance of it directly.

While the restructuring of electric markets has limited the application of IRP in many regions, it remains very relevant, *especially* for isolated electric systems. The Hawaiian Electric Company is a leader in this regard:

> How do we ensure that Hawaii's energy needs will be met reliably and affordably for the years to come? It takes selecting the best mix of energy resources. That choice is not a matter of "either/or," but rather an array of solutions, combining conservation and energy efficiency, renewables, distributed generation technologies as well as clean and efficient central power plants.
>
> To find the right mix, Hawaiian Electric uses a process called Integrated Resource Planning (IRP). The Hawaii Public Utilities Commission (PUC) established IRP in 1992 for electric utilities to forecast energy demand and analyze the best ways to meet it. No other sector regulated by the PUC goes through such a thorough and far-reaching planning process.
>
> In IRP, an outside advisory group representing business, government, energy regulators, consumers, environmentalists, and other interested stakeholders work closely with utility planners and engineers. They consider population growth, culture, lifestyle, the economy, the environment, available energy technology and other factors.
>
> Hawaiian Electric, Maui Electric and Hawaii Electric Light companies each undertakes a separate IRP process for its service territory.

[2] Litchfield, Hemmingway and Raphals, Integrated Resource Planning and the Great Whale Public Review.

Hawaiian Electric has begun its fourth IRP Process which is expected to result in a new 20-year plan being developed and filed with the PUC in mid-2008.[3]

The most recent IRP report of the Hawaiian Electric Company (HECO) is attached.

Hawaii, like Newfoundland, is anxious to find ways to use indigenous renewable energy to replace fossil fuels. However, unlike Newfoundland and Labrador, it is approaching the question in a structured fashion designed to discover and compare all possible solutions, in order to choose the best one.

Hawaii Clean Energy Initiative

- Hawaii and the U.S. Department of Energy signed the groundbreaking Hawaii Clean Energy Initiative in January 2008.
- Working groups include End-use Efficiency, Electric Generation, Energy Delivery and Transportation.
- Hawaiian Electric strongly supports the agreement to move away from reliance on fossil fuels and is participating in all four working groups.

In January 2008, Hawaii Governor Linda Lingle and Assistant Secretary for Energy Efficiency and Renewable Energy Alexander Karsner, representing U.S. Department of Energy, signed the groundbreaking initiative.

The goal of the initiative is "to decrease energy demand and accelerate use of renewable, indigenous energy resources in Hawaii in residential, building, industrial, utility, and transportation end-use sectors, so that renewable energy resources will be sufficient to meet 70% of Hawaii's energy demand by 2030."

The Hawaiian Electric companies strongly support the agreement, and have pledged to do their part to reach this goal by providing electricity for Oahu, Maui (including Molokai and Lanai), and Hawaii Island without fossil fuels. Renewable resources include solar, wind, water, geothermal, biomass including waste, and biofuels with a preference for those that can be produced and processed locally.

Under the agreement, Hawaii will be a test ground for a portfolio of renewable energy technologies. The state will also pioneer financial, policy, and business models that the signers hope can be replicated throughout the United States.

At the signing, Hawaiian Electric President & CEO Mike May offered the utility's full cooperation and participation. "This initiative is both visionary and practical, he said. "Its goal -- the energy transformation of our state -- is truly visionary and should be an example to others across the country and around the world. And it also recognizes that vision must be implemented the right way.

3 http://www.heco.com/portal/site/heco/menuitem.8e4610c1e23714340b4c0610c510b1ca/?vgnextoid=b71bf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=defau

"It is practical in recognizing the cost and responsibility of implementing solutions must be shared broadly by all stakeholders, including state and federal government, private industry, and every citizen.

"And perhaps most important, designing the path for Hawaii's energy future must consider all that is unique about our islands. One size may not fit all. Prescribed mainland solutions may not be the answer for our island economy and environment. So this is a special opportunity to do what is right for our state."

Hawaiian Electric is participating in each of the four Hawaii Clean Energy Initiative working groups:

- **End-use efficiency**, with the ultimate goal of achieving zero net-energy buildings and communities, and dramatic reductions in other significant end-use areas, including military bases and installations;

- **Electric generation**, including expanding and optimizing the use of renewable energy at central and remote locations, improving generation efficiency at existing plants, and facilitating the installation of distributed renewable generation across the State;

- **Energy delivery**, including transmission and distribution improvements, grid management improvements, and energy storage to ensure that the existing and future infrastructure facilitates optimal use of renewable resources and readily adapts to and incorporates new developments in system planning and transmission technologies while maintaining system reliability; and

- **Transportation**, including the establishment of a long-term, sustainable strategy for the production, distribution, and use of alternative transportation fuels, thereby accelerating the adoption of advanced vehicle technologies such as plug-in hybrids, and promoting mass transit[4]

Load growth

On pages 17-18, the Response shows that electric heating market share has increased from 10% in 1985 to over 60% today. This response demonstrates that increasing penetration of electric space heating is a major driver of electric demand. Indeed, given the stagnancy of population growth and industrial growth in Newfoundland, electric heating growth may be the primary driver for demand growth.

It is universally understood that electric heating is highly undesirable, from a policy perspective, wherever fossil fuels are used to generate electricity, since fossil fuel generation efficiencies are below 50%, compared to efficiencies of 80% or over when they are used for heating.

4 http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=a69190a2decab110VgnVCM1000005c011bacRCRD&vgnextfmt=default&cpsextcurrchannel=1

Many regions use explicit policy incentives to discourage electric heating. Efficiency Vermont offers rebates of $3,000 to convert from electric heating to natural gas.[5] Efficiency New Brunswick also encourages alternatives to electric space heating.[6]

Newfoundland and Labrador, like Quebec and many other regions, uses specially designed rate structures to discourage electric heating in communities supplied by diesel generators. In fact, given the important role of Holyrood in meeting the Island's winter power needs, the situation is no different on the Island: electric heating imposes very substantial economic and environmental costs. Apparently, there are no policy efforts underway, either by the provincial government or the utilities, to restrain the trend toward electric heating. In its earlier presentation, the Proponent suggested that oil is the only alternative to electric heat, neglecting an abundant renewable resource – wood. Many rural homes have wood stoves – why are they not encouraged to use them? As Mr. Davis pointed out in today's hearing, wood pellet stoves are a modern and realistic option for space heating, that do not require as much effort as a wood stove.

The Proponent seems to see the trend toward ever-increasing use of baseboard heating as an inevitability. Indeed, this is the way utility planning used to work: forecast the loads, and find the least-cost generation solutions to meet them. It has been more than 20 years since this paradigm gave way to the Integrated Resource Planning paradigm, whereby the planner looks simultaneously at supply- and demand-side alternatives for meeting needs for energy services. The approach to building Conservation and Demand Management (CDM) programs based on avoided costs is a consequence of this paradigm shift.

CDM

The Response mentions that "to date, the utilities have seen lower than predicted initial savings" (p. 16), but does not make clear how far behind the utilities are, in relation to their own five-year plan.

The following graph shows actual energy savings reported by NLH and NP in their annual CDM reports to the PUB:[7]

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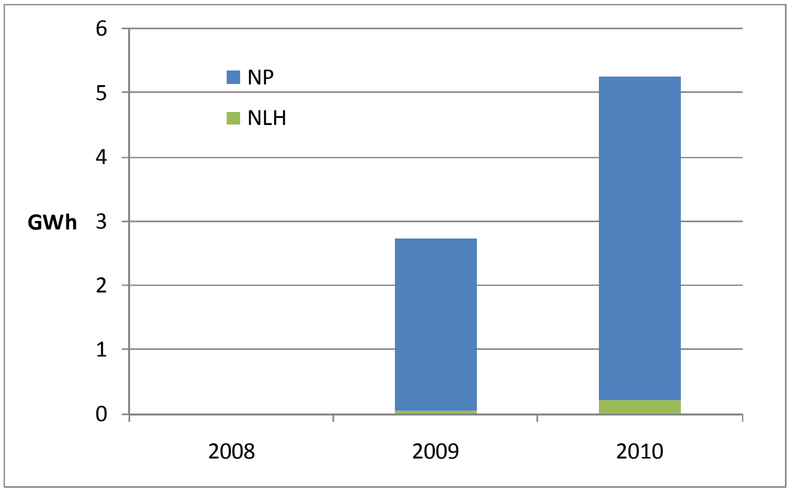
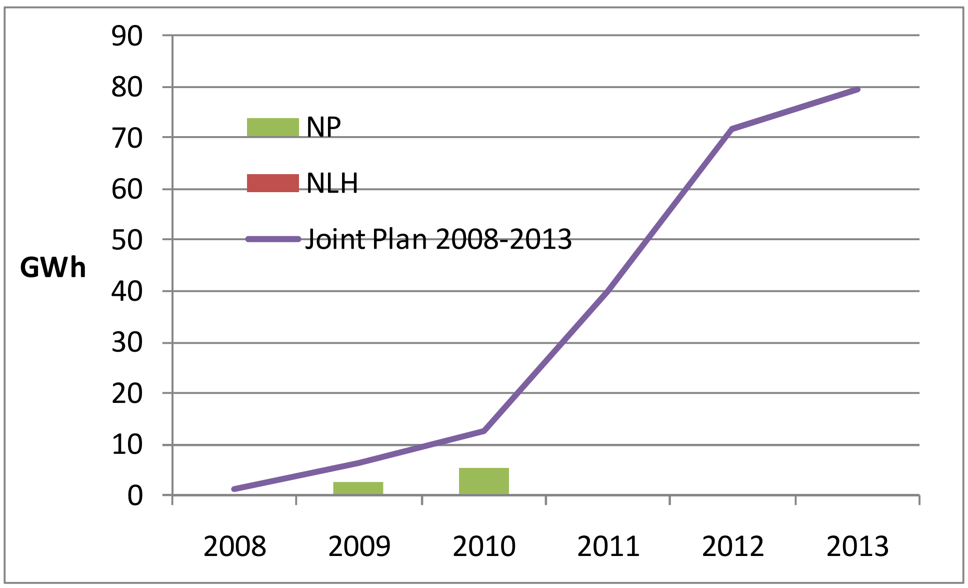
[5] http://www.efficiencyvermont.com/for_my_home/ways-to-save-and-rebates/energy_improvements_for_your_home/heating_and_cooling_your_home/rebates.aspx

[6] http://www.efficiencynb.ca/residential/moving-away-from-electric-space-heating.html

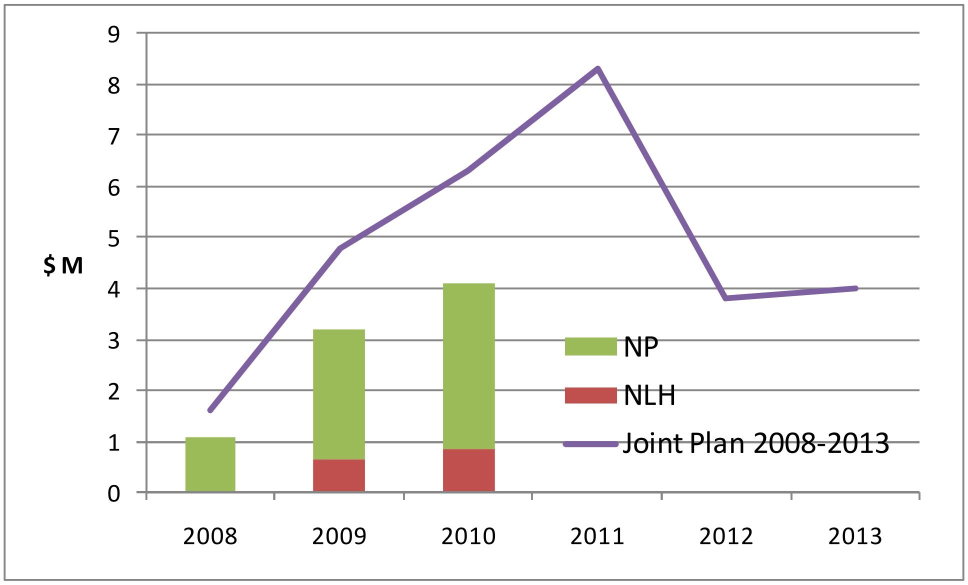
[7] Sources for the following three graphs : NLH 2011 Conservation Cost Deferral Report, Feb. 2011, p. 5; Newfoundland Power, 2010 CDM Report, Feb. 28, 2011, pp. 5-8; NLH/NP Five-Year Energy Conservation Plan, 2008-2013, June 2008, pp. 11-13.



To put these figures into perspective, it is necessary to compare them to the targets set in the Five Year Joint Energy Conservation Plan 2008-2013:



These results flow in large part from the allocation of funding to CDM programs, which have also lagged far below that which was planned:



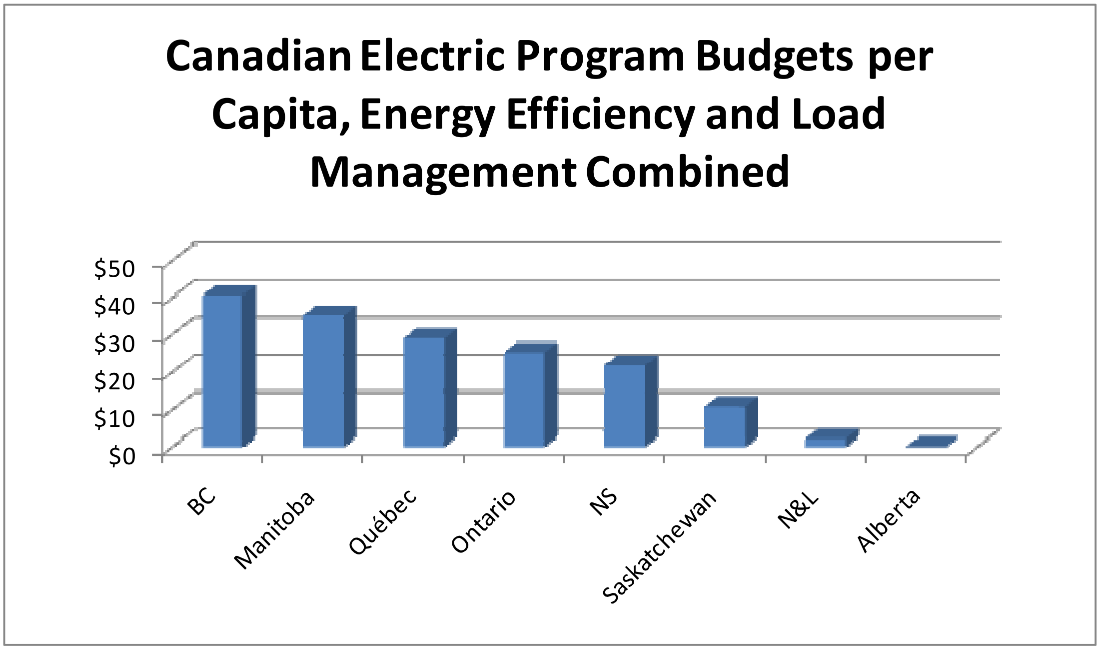
Generally speaking, these graphs suggest that NLH and NP have lagged approximately 50% behind the objectives set in the 5-year plan.

As noted above, the Proponent failed to provide a direct response to the Panel's requests to determine the effects on CDM savings under different scenarios (Part B, Scenario 2, Questions 3 and 4). It declined to estimate the increase in the cost-effective CDM potential that flows from the dramatic increase in avoided costs since the Marbek study, nor did it estimate the potential that could be realized if CDM budgets were increased to 1.5%, 3% or 5% of electric revenues. While it is clearly problematic to provide precise, quantitative responses to these questions, qualitative response would indeed have been possible. As a result, it was of course unable to estimate the consequences for system planning.

The Proponent reports that current CDM budgets account for just 0.75% of utility revenues, while acknowledging that, according to Marbek, 1.5% is "an appropriate level for a jurisdiction in the early stages of CDM planning." Thus, the NL utilities are again lagging 50% behind the level Marbek thought appropriate for their early stage. Marbek then suggested that funding levels should normally ramp up to 3% once experience is gained (p. 21). However, CDM budgets in the province are only ramping up towards 1.5% (p. 22). Again, we are 50% behind, both in effort and in results.

The Response fails to clearly indicate just how far behind NLH and NP are, compared to other Canadian or American utilities, in their CDM efforts. More perspective can be found in the Consortium on Energy Efficiency report referred to on page 21 of the Response.[8] One of the best indicators is per capita expenditures, shown in the following graph:

[8] The CEE produces annual reports on the State of the Efficiency Program Industry. The data on p. 21 of the Response came from some of the supporting tables of this report. The data underlying the following chart comes from Table 15 of the 2010 Report.



According to the CEE, Newfoundland and Labrador utilities spend just $2.22 on CDM per capita, compared to $29.02 in Quebec and $40.63 in BC.

<u>Wind energy</u>

The responses to Scenario 3 of Part B, Financial Analysis of Alternative Generation Sources on Island, are particularly deficient, in that they ignore the wind resource altogether.

In the section entitled "System Planning and Hydrology," the Proponent explains that the main constraints are winter availability and storage (p. 23).

- "Without additional storage to ensure that energy is available from new resources when it is needed, additional small hydro or wind production will simply result in increased probability of spill at existing facilities." (p. 24)
- The integration of less reliable renewable is not constrained by the ability of NL Hydro's existing generation to respond to variable output, but rather by the inability of the less reliable renewables to deliver energy when it is required during the peak winter season. The integration of less reliable renewables is liminted by the finite hydroelectric storage and inability to market this surplus energy, rather than the short term integration of hydro and less reliable renewables" (p. 34)

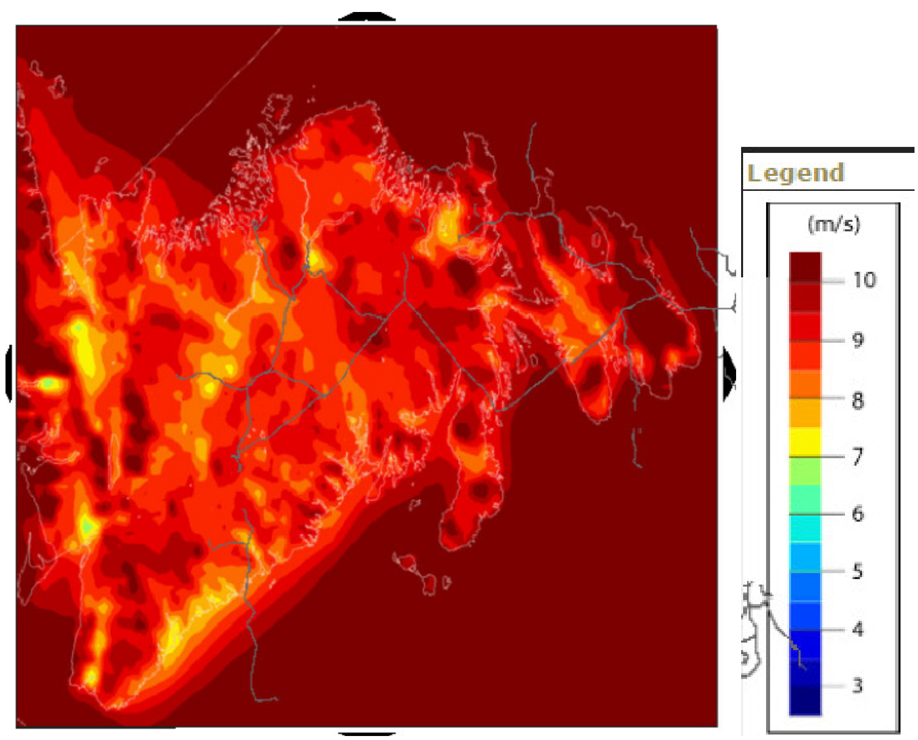
Furthermore, the Proponent's response to question #3, concerning the investment required to integrate other renewables, addresses **only** the integration of small hydro east of Bay d'Espoir, arguing that $1 billion in transmission upgrades would be necessary to integrate these small hydro projects, which in any case do not have the storage required to meet winter loads.

It is hard to understand why the Proponent did not also address the integration of wind power. Mr. Bown had earlier explained that the province had chosen not to pursue further wind development until after Muskrat Falls and associated transmission are in place:

> The policy right now is that we are not going to take on any more wind development on the Island until such time as we are connected to a grid that will enable us to utilize the full benefit of that. ...
>
> there is only so much wind energy that we can use on an isolated system. And if you apply too much wind and that there is -- and you enter into a contract where you have to take that wind, then you run the risk of having to spill water should you need to take that load when the demand is down. *(March 7, p. 292-93)*

This is at best a superficial understanding of the wind energy opportunities on the Island.

As the Energy Plan recognizes (pp. 36-37), the Island's wind resource is world class. The Plan shows the wind map for the province at 50m height, and it is still all red – unheard of in Canada. At 80m, the height actually used by modern wind turbines, it is even better (and redder):



The Canadian Wind Energy Atlas (www.windatlas.ca) is a powerful tool to evaluate wind potential. Choosing a point pretty much anywhere on the Avalon Peninsula, it gives results like this:

Calculation of the turbine formula for a given wind turbine at 80m

Latitude = 48.175, longitude = -54.727

Enter wind turbine data (all fields are required):

max power output (kW):

cut-in wind speed (m/s):

rated wind speed (m/s):

Submit Clear

Calculation for the data you entered (2000,3.5,12):

Period	Power Output	Energy Output	Use factor
Annual	1173.15 kW	10283.87 MWh/year	58.66 %
Winter (DJF)	1347.82 kW	2953.75 MWh/period	67.39 %
Spring (MAM)	1182.58 kW	2591.63 MWh/period	59.13 %
Summer (JJA)	1028.89 kW	2254.80 MWh/period	51.44 %
Fall (SON)	1190.61 kW	2609.23 MWh/period	59.53 %

This data represents a 2 MW wind turbine, 80m high, at the geographical coordinates shown above. The results show that the average annual use factor is 58.66% -- almost double the 30% often used as a rule of thumb for wind power. Furthermore, the winter production is even higher – 67.39% of installed capacity. This demonstrates that the characteristics of wind power on the Island is very different from that of small hydropower, as described in the Response, which has low availability in winter when demand is highest, due to low river flows.

This means that – putting aside for the moment the question of intermittency – Island wind power is more a baseload resource than a seasonal one. Intermittency is indeed a significant issue for wind integration, but it is one for which there are many solutions. Geographical diversity is probably the most important one – the more that wind turbines are dispersed geographically, the more they tend to compensate for each others' intermittency, resulting in a total generation profile that is increasing flat, as the geographic diversity increases.

I studied this phenomenon in detail, based on real wind measurements from five sites across Quebec, in joint expert testimony (together with Tim Weis, of the Pembina Institute) submitted to the Quebec Régie de l'énergie in 2008.[9] This report built on a data simulation prepared earlier by Mr. Weis concerning the 990 MW of wind power currently being installed in the Gaspé region of Québec, attached as Appendix I, which addresses in detail the smoothing phenomenon (see in particular section 2.2).

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[9] P. Raphals, Implications pour le Distributeur de l'ajout de parcs éoliens en Gaspésie, R-3550-2005, May 25, 2005, http://www.regie-energie.qc.ca/audiences/3550-04/Memoires3550/RNCREQ-8_3550_RapExpertRaphalsCORRIGE_14juin05.pdf

In my testimony for the supply plan hearings of 2008,[10] data was obtained from wind developers from five sites in different locations in Quebec. The analysis of these data was confirmed by Mr. Weis. While the focus of the study concerned features specific to the Quebec regulatory regime, section 3 reviews the smoothing effect due to the geographical diversity of the five measurement sites. Obviously, the greater the number of wind turbines and wind farms, and the greater the distance between them, the greater the diversity effect.

The system explanations in the Response and in the earlier testimony makes clear that:

- Holyrood is used in the winter only
- The constraint on adding less reliable renewable due to inability to store energy for the winter
- Adding baseload resources to meet winter demand that cannot be modulated would lead to spillage from the hydro system in the summer.

It is for these reasons that the government and the Proponent are not interested in developing a large, geographically diversified wind resource on the Island. However, it is important to realized that the profile of such a development would be very similar to that of the Muskrat Falls hydroelectric project. And, just like the wind farm, Muskrat Falls would lead to extensive spillage during the summer, if the transmission line were not built to Nova Scotia.

We thus realize that Muskrat Falls and an 800 MW wind farm on the Island are very similar resources – both are essentially baseload, with little if any storage or dispatchability; both require an export path to be developed economically.

There are, of course, differences. MF is not dispatchable either, though the Water Management Agreement does provide a very small margin of manoeuvre.[11] A group of five 200-MW (installed) wind farms, with an average use factor of 58%, would produce 5 TWh a year – the same as Muskrat Falls. Siting is of course a critical issue. It would be desirable to locate as much of the resource as possible on the Avalon Peninsula, where the loads are greatest, but geographical diversity will reduce variability and increase firmness. Obviously, siting should also take transmission access into account, and be designed to minimize necessary upgrades. Fortunately – and Newfoundland is unique in Canada and perhaps in the world, in this regard – the wind resource is so good and consistent that these wind farms could be located practically anywhere on the Island.

Careful study would of course be needed to understand the firmness of this power, taking into account the geographical diversity of the proposed resource. Once these studies are done, it will be possible to assess the degree of firmness of their combined output, and hence the measures needed to "firm" the output. À la limite, that could involve maintaining Holyrood as spinning reserve – though smaller and

[10] P. Raphals, L'énergie éolienne, l'équilibrage, et la demande de pointe, dans le contexte du contrat patrimonial, R-3648-07, March 28, 2008, http://www.regie-energie.qc.ca/audiences/3648-07/MemoiresInterv3648/C-13-9-ROEE-RNCREQ_RappExpAmende_3648-2_30mai08.pdf.

[11] See WATER MANAGEMENT CHART, which shows that the differences in monthly output with and without the agreement is relatively subtle.

more modern equipment could probably do the job more efficiently, at lower cost and with lower air emissions.

Given the extraordinary wind resource on the Island of Newfoundland and in particular on the Avalon Peninsula, the development costs per unit energy would be considerably lower than elsewhere in Canada.

We did some rough modelling to determine the costs of a wind development to produce 3.9 TWh/yr. The all-in capital cost would be under $2.5 billion, with annual operating costs of $50 million (less than those of Muskrat Falls).

Given the quality of the wind resource, the power density is estimated at 1.5 MW/square km.

Real levelized cost of power: $75/MWh.

Production to be displaced (MWh)	3 900 000	
Expected average capacity factor of windfarm	45%	
Required intalled capacity (MW)	989	
All in captial costs of wind ($/MW)	$ 2 500 000	
All in annual operating cost of wind ($/MW)	$ 50 000	
Cost of installing required capacity ($)	$ 2 471 670 849	
Annual operating costs of required capacity ($)	$ 49 433 417	
Installed capacity per square km (MW/km^2)	1,5	
Overall land required for required installed capacity (km^2)	659	
Price of Power ($/MWh)	$ 75	
Portion of price escalated	15,00%	
CPI	2,50%	
Escalation of Price of power	0,38%	
Equity Ratio	30,00%	$ 741 501 255
Debt Ratio	70,00%	$ 1 730 169 595
Debt interest rate	6,00%	
Payment period	15	
Yearly debt payments	-$178 143 043,58	
Equity IRR (25 years)	11,55%	
Unlevered IRR	7,67%	