Comments on the Muskrat Falls Reference

Presentation to the Public Utilities Board of Newfoundland Labrador

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on behalf of Grand Riverkeeper Labrador Inc.

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Good morning. My name is Philip Raphals. I am Executive Director of the Helios Centre, a non-profit energy research group in Montreal. I am here on behalf of Grand Riverkeeper Labrador. I also provided expert testimony on Grand Riverkeeper's behalf in the Environmental Assessment hearings concerning the Lower Churchill Generation Project.

A few words about my background: In the early 1990s, I was deputy scientific coordinator of the environmental assessment of the Great Whale Hydroelectric Project, a 3000 MW hydro project in the James Bay region, that was never built. Since cofounding the Helios Centre in 1997, I have appeared as an expert witness before the Quebec Energy Board in hearings concerning Hydro-Quebec's rates, energy efficiency programs, supply plans, and transmission tariffs. I have also worked on a large number of energy issues for clients in Canada and in the US, and I chair the Renewables Advisory Committee of the Low Impact Hydropower Institute in the US.

I have a number of comments to make to you about the MHI report, and the Reference Question generally, in particular with respect to the issues of :

1. CDM in load forecast
2. Fuel price forecasts
3. Wind power assessment

I am well aware of your Terms of Reference, and that they do not include a review of other options. I will address these issues solely in the context of the analysis of the two options before you.

In support of my comments, I would like to produce several documents that I believe the Board will find useful,. I emailed them to you earlier, and I will mention them when appropriate.

I would also like to mention that I submitted a number of IR's via the Consumer Advocate, none of which have yet been answered. This is an unusual situation, and I would like to reserve the right to modify or supplement my comments, if necessary, once the responses are made available.

First, I would like to comment on some of the earlier exchanges before you.

In a followup to his first question to the Nalcor panel, the Consumer Advocate asked: "how did you ensure that as between the two options you were comparing that you were dealing with the optimal scenario under each one?" (Feb. 13, p. 89-90)

An excellent and important question.

To which Mr. Humphries replied, "within each one ... we had a number of scenarios and generation sources that fit into those, that were fed into the input and the Strategist program then did an optimization to ensure that within each of these alternatives that the least cost scenario was developed for the Isolated Island, as well as the Interconnected case."

In other words, if I may paraphrase, we know each scenario is optimal because it was produced by Strategist, which is produces optimal scenarios.

This answer seems to suggest that all we need to find the optimal resource plan – and recall that, until the Emera agreement was announced, the Isolated Island scenario was, in fact, Newfoundland's resource plan – is the right computer program.

To see what is wrong with this view, let us imagine that the Emera Agreement didn't exist, and that the Lower Churchill Generation Project had gone ahead as initially planned. Gull Island and Muskrat Falls have been built, the interconnection to Quebec has been reinforced, the open access reservation on the Hydro-Quebec system is in force, and all that energy was presold to buyers in New York City, making lots of money for Nalcor and the NL government. And the Island remained isolated.

In that world, as we approach 2017, fuel prices are rising according to the reference scenario, and everything else is unfolding as set out in the Isolated Island Scenario. Rates are going up, with no end in sight.

In that world, what would have happened over the next 10, 20 or 50 years? According to the Isolated Island Scenario, 25 MW of wind would come on line in 2014; Island Pond in 2015; the Holyrood upgrade starting in 2015; and so on. And rates would keep going up, as forecast.

And what would all of us be doing, during those years? Going about our business, of course, working on other issues, because we already know the optimal solution. It was developed by Strategist in 2011!

I don't think this is the way it would go.

A lot of very bright people, many of whom are in this room, would be doing their darndest to find better solutions. And I have no doubt that they would succeed.

And might would those solutions include? Ways to control load growth, for starters. Utilities all over the world, confronted with situations where the marginal costs of serving new load are much greater than the average costs of serving existing load, have been doing this for many years – often with great success. For example, given the importance of electric heating in Newfoundland's load growth, I wouldn't be surprised to see programs to promote the use of heat pumps, which have high capital costs but are much more efficient that resistance heaters.

I suspect you would also take a hard look at your wind resource – one of the best in the world – to try to find solutions to the limitations currently in force. (I'll come back to that later.) And I suspect the same is true of your offshore gas resource. Around the world, as oil prices are going up, gas prices are going down. With a domestic gas supply – granted, not easy to exploit – I'm certain that serious thought would go into finding a way to make it part of the solution.

Strategist, and the other programs like it, are very powerful tools for exploring the consequences of different actions and strategies. I'm sure they would be put to good use in the ongoing effort to find lower cost solutions to Newfoundland's energy needs.

But while it is one thing to come up with these solutions over the years, in real time, it is quite aanother to come up with them all at once, in advance, in a plan. But utilities have been doing that for years too, in processes called Least Cost Planning or Integrated Resource Planning.

These processes also start with a load forecast, a set of resource options and their costs, and an optimization program like Strategist. But if all we needed was the program, these planning processes wouldn't exist.

In fact, Strategist is just a beginning. Then, it takes a lot of hard work, to find ways to improve the plan, to make it better and more robust.

This, indeed, is one of the most important differences between the Interconnected scenario and the Isolated Island Scenario: the former has had thousands of man-hours of effort put into it to perfect, optimize, and reduce uncertainty, as detailed in the earlier testimony. The Isolated Island scenario remains an early draft.

And there's another important difference. If the Muskrat projects go ahead, we have a very good idea what the Island power system will look like in 50 years. But if it doesn't, we really don't. Because the chances that the future will unfold precisely as set out in Strategist's Isolated Island Scenario are very small indeed.

It is important to emphasize that these scenarios are optimized **for a given set of assumptions.** MHI made this point clearly in the closing paragraph of its Executive Summary, when it said:

> With projects of this magnitude, and considering the length of the analysis period, there are risks and uncertainties associated with the key inputs and assumptions. Changes in these key inputs and assumptions will affect the financial results and must be assessed to determine materiality. These changes in key inputs and assumptions can impact the results of the analysis and shift the preference for what is the least cost option.

In other words, we really don't know which option is least cost, because we don't know which inputs are the right ones.

The problem is, those assumptions and hypotheses will inevitably be contradicted, or at least refined, by reality, as it evolves – indeed, they almost certainly will be. As MHI wrote (v.2, page 205), fuel price forecasts have a "short shelf life".

So the real challenge is to find a plan that is optimal, not just based on current assumptions, but that is **robust** over a broad range of possible futures.

The challenge is to try to understand the implications of the possible twists and turns of fate, and to try to avoid taking irrevocable actions that would turn out badly if reality turns out to be different from the planning assumptions. Preparing such a long-term energy plan is an iterative process in which programs like Strategist play a very important role. But the program's output represents the beginning of a planning process, not the end.

To take one example, the Northwest Power Plan, produced by the Northwest Power Planning Council took years to produce, and is 300 pages long (plus appendices).

Clearly, the Isolated Island Scenario is a scenario, not a plan. If load growth is greater, or lower, than the Reference Forecast, the need dates for resources will have to be adjusted. If the economic analysis underlying the wind power limitation is modified, or if new integration techniques become available, resource choices will change.

Given all this, I can't help but think that, had the Government asked you to compare the Interconnected scenario to isolated island scenari**os**, plural, rather than comparing it to The Isolated Island Scenari**o, singular,** the substantial resources devoted to this exercise would have been better spent. But that is not your mandate. ...

That said, I find that MHI has done an excellent job of pointing out the limitations of this scenario – limitations which would be overcome if it were used as the first step in an in-depth planning process.

However, I find that MHI has also missed a couple of important points, which I will focus on in the time I have left.

PPA versus COS

One of the key issues for the Muskrat Falls project is the pricing policy. This is addressed in Exhibit 36, PUB-Nalcor-46, and other documents.

On Feb. 15, this issue came up when the Consumer Advocate asked, "does the 2035 ratepayer have to pay more so that the 2017 ratepayer can pay less?" (page 18)

In response, Mr. Goudie correctly pointed out that, under a conventional cost of service arrangement, the unit cost would be highest in the initial years, and lowest in later years, so that people 50 years from now would pay very little. (p. 19)

Then, Mr. Bennett pointed out that, under the proposed PPA, people 50 years from now would pay the same price, **in inflation-adjusted terms**, as in 2017. (p. 20).

Nalcor then explained that the different cost recovery patterns set out in CAKPL-27, rev. 1 are all equivalent.

All this is true. But it's not the whole story. From an economic perspective, the three lines shown on pages 4 and 5 of this document are of course all equivalent ("annual nominal cost", "nominal LUEC" and "Escalating real LUEC"). They all have the same present value and are thus interchangeable from Nalcor's point of view. That does not mean, however, that they are equivalent from the consumer's point of view.

To think this through, I suggest we use the image of a mortgage, with which we are all familiar. It is not an exact analogy, but I think we can make the necessary adjustments.

The typical mortgage payment plan is similar to the one at the top of page 5, the nominal LUEC, where nominal payments remain the same from the beginning to the end. Thus, I might make the same monthly payment – let's say $1000/month, for 25 years, until the principal and interest are paid off.

In reality, of course, there is inflation during those 25 yrs, which means that the real value of my constant nominal dollar payments decreases. So even though I pay a flat $1000 a month, it will 'hurt' less 25 yrs from now, because the money will be worth less.

Now, what about the escalating payment plan? Since the present value is the same, the bank could offer me the option of paying the same real dollar amt per year, which would translate into a nominal dollar payments that increases 2%/yr or so, with inflation. It would look a lot like the lower graph on page 5, starting at less than $1000/month, and increasing with inflation.

Now, given a choice between these plans, how many consumers would choose the second one? Not many, I think. The idea of constantly increasing mortgage payments, even if they are theoretically the same (in constant dollars) would scare most of us off.

The question that was asked on the 15th was “does the 2035 rate payer have to pay more so that the 2017 rate payer can pay less”? And I think the right answer is that, Yes, he does. Future ratepayers will indeed pay much more for Muskrat Falls power under the escalating payment plan than they would with levelized payments.

Now, this all assumes that Muskrat Falls is owned by a non-regulated party (Nalcor), with the power sale governed by a PPA. If it were a regulated ratebase asset, the situation would be very different.

In Exhibit 36, Nalcor explained why it chose a PPA over COS, but I don’t find the explanation very convincing.

Traditionally, hydro projects have been developed as ratebase projects under COS principles, which implies higher costs in the first few years, that decrease dramatically over time. That’s why the costs of Bay D’Espoir are so low now. If it had been built under a PPA, instead of COS, it would cost Newfoundlanders far more today.

In the exchange quoted earlier, Mr. Bennett also said:

> And maybe, building on that point, the customers in 2068 who have an asset that’s, whose costs are fully recovered will have a similar situation as we’ve seen with Bay d’Espoir. (p. 21)

According to the transcript, the chair then said, “I can’t wait” (p. 21). I believe you were referring to the expectation that, eventually, the costs of MF will be as low as those of Bay d’Espoir.

But I am afraid, sir, that you will be disappointed. Under the proposed regulatory framework, Muskrat Falls may never be a low-cost resource. Let me explain.

The tables provided at the end of CAKPL-Nalcor-27 rev. 1 allow us to better understand the proposed pricing formula, which is meant to cover both the PPA of Muskrat Falls and the actual costs of the Labrador-Island Link, under COS pricing. I have prepared a new version of this table that adds a few columns to separate out these two elements (GRK-3).

Nalcor's column 5 shows the nominal annual cost, in $/MWh, of the whole project. This cost remains relatively constant, varying between $190 and $260/MWh over the life of the project.

My new columns 5a and 5b break down the nominal annual cost between MF and LITL, by dividing the incremental costs of each (columns 2 and 3) by the total energy (column 1). We see that, while the nominal annual cost of LITL falls (from |$147/MWh at the beginning to $13 at the end), the annual cost of MF increases, from $92 to $247/kWh.

These combined costs are then levelized, on a nominal basis, in column 6, resulting in a fixed nominal dollar cost of $208/MWh. Again, I have broken this down into MF and LITL components, using the same methodology described in Nalcor's note 2. The levelized nominal LUEC for MF is $126/MWh, and that for LITL is $83/MWh.

In column 7, I have only changed the title. While Nalcor calls it an "escalating real LUEC", I find this confusing, since the figures are actually in nominal dollars, not real ones. I find it clearer to refer to it as a "Real LUEC expressed in nominal dollars". In other words, we have converted the nominal LUEC to real dollars, and then re-translated it back into nominal dollars, as a price that escalates with inflation. These are thus the actual prices, in current dollars, that will be charged to consumers for Muskrat power (delivered to the Island and blended, of course, with other sources), which starts at $152/MWh in 2017 and increases to $409/MWh in 2067. (Nalcor's figures, from col. 7.)

In column 7a, I have indicated the total annual payments (MF plus LITL), in current dollars. (That's the energy from column 1 times the current dollar prices, in column 7.) In column 7b, I have subtracted from that the LITL payments in column 3, to show the current dollar payments under the MF PPA. Then, in column 7c, I have calculated the current dollar unit cost for Muskrat Falls power (without transmission), by dividing by current dollar payments in column 7b by the amount of energy, from column 1.

Column 7c shows that the actual price paid to Nalcor for Muskrat Falls power starts at $5/MWh in 2017, and rises to $396/MWh in 2067. This result – more extreme than the blended result shown by Nalcor in column 7, results from mixing PPA and COS costs, and from the fact that customers must pay the full cost of LITL, under COS, but only for the energy they actually consume, under the PPA. But in either case, the price to be paid for Muskrat Falls power under the PPA in 2067 comes to around $400/MWh, or 40 cents/kWh.

Now, if I am not mistaken, the costs of Muskrat Falls power under a COS regime have not been produced in this file. However, the information in this table allows us to estimate that as well.

Making the simplifying assumption that the capital structure and depreciation of MF are similar to that of LITL, we can simply inflate the LITL payments in column 3 to correspond to the MF CPW of $2.682 billion (column 2). The result, shown in column 8a, shows the annual current dollar payments that would be required to cover the costs of Muskrat Falls under a COS regime identical to one applied to LITL. These costs start at $407 million in 2017, and fall to $90 million by 2067. Column 8b then shows this amount divided by the total energy each year, giving the unit cost in $/MWh for Muskrat Falls energy under COS. It starts at $225/MWh in 2017, and then fall to $20/MWh by 2067. Of course, if consumers were credited with the revenues of third party sales, which would be normal in COS, the early-year costs would be lower.

This little exercise shows the real difference between COS and PPA pricing. With the PPA, Muskrat Falls prices are much lower at first, but 20 times higher in 2067.

So Mr. Bennett was right: If Muskrat Falls were subject to COS regulation, in 50 years it would be almost as cheap as Bay d'Espoir.

And what happens after 2067? Under COS, the unit cost from MF would remain stable, somewhere around $20/MWh or lower, like it does for other COS hydro projects.

Under the escalating price scenario, however, NF consumers would be paying $396/MWh for MF power in 2067. How much would Nalcor charge in 2068? Would it suddenly cut the price to $20/MWh, pointing out that, since all its costs incurred 50 years ago had now been paid, it had no reason to charge more? Or, more likely, would it keep on charging $400/MWh?

Doing so would of course produce a windfall profit for Nalcor and its shareholder – paid from the pockets of Newfoundland consumers.

At Churchill Falls, Hydro-Quebec enjoys pricing very similar to COS pricing, and Newfoundland and Labrador certainly wishes that the pricing were more like the PPA proposed here. But in the case of Muskrat Falls, it is Newfoundland consumers who will be paying the escalating prices. In my view, COS pricing would be far better, from the customer's point of view.

CDM

In vol. I, p. 31, MHI explains in its generic description of the generation planning process that, "Demand side management is treated as if it were generation, as it represents a reduction from the base load forecast. The economics of DSM programs should be evaluated to ensure that they make a positive contribution to the overall financial well-being of the province." (vol. I, p. 31)

However, the approach used by NLH is very different. Section 1.8 of vol. II begins:

"It should be noted that the domestic forecast does not include any specific, exogenous adjustment for specific Conservation Demand Management (CDM) programs. The NLH method of capturing and estimating CDM effects is through the technological change variable contained in the regression equations."

MHI then explains that this variable has a coefficient of -35.37, meaning that average domestic use is forecast to decline by 35.37 kWh per year over 20 years.

There are several problems with this approach. First, it assumes, for no good reason, that CDM progress is linear, gradual and inexorable. More important, it assumes that it does not depend on utility actions.

In table 17 (p. 34 of v. 2, in section 1.9), MHI compares Nalcor with three other Canadian utilities, but unfortunately the comparison does not include the methodology for capturing and estimating CDM effects.

MHI criticized Nalcor for preparing its domestic forecast using only econometric modelling techniques which, it explains, are NOT the best utility practices in this area (v. 2, p. 20 and 39). It points out that the domestic load forecast is primarily driven by electric space heat, and it emphasizes that developing an end-use forecasting model would have many benefits, including improving the design of CDM programs.

I find it remarkable how little attention is paid in the MHI report to CDM programs, as such. It is clear that the planning methodology described by MHI is not applied by Nalcor. By failing to treat CDM as a resource, it is impossible to assess the optimal level of investment.

I suggest that the forecasting methodology identified by MHI may be one of the reasons that Nalcor has failed to meet its own CDM objectives to date, and why its future CDM objectives are so weak. MHI clearly indicated that “The amount of variability due to potential load changes is high and could materially impact the results of the cumulative present worth analysis” (v. 2, p. 39). Given the clear relationship identified by MHI between future loads and the CPW differential between the two scenarios of the Reference Question, this issue goes to the heart of the Board’s reflections.

I previously looked in some detail at the results of NLH’s and NP’s CDM programs to date. In the third year of their Five Year Joint CDM Plan 2008-2013, they had accomplished less than half of the savings forecast for that date. Actual CDM funding through 2010 was also very much lower than planned.

Surprisingly, the MHI report is silent about this important point.

Why is it so important? Because, as MHI has indicated, the perceived CPW difference between the Infeed and Isolated Island scenarios are very sensitive to load growth, which of course really means, load growth net of CDM.

More specifically, MHI’s Sensitivity Summary, Table 42 (vol. 2, page 207), shows (item 2) that when annual load is decreased by 880 GWh, the CPW difference between the two Scenarios decreased from $2.1 billion to just $408 million. Furthermore, Exhibit 43 Rev.

1, on its first page (with detail on p. 62), shows that, with a decrease of 1086 GWh, the difference becomes nil.

Exhibit 43, rev. 1 explores three load growth sensitivities: a) a flat decrease of 880 GWh/yr, starting in 2013; b) a flat decrease of 1086 GWh/yr, starting in 2013; and c) a gradual decrease equal to 50% of the forecast load growth each year, from 2015 to 2067. This last scenario is described in detail on the last page of the document (p. 62).

It is hard to see how the first two scenarios are very meaningful. They represents a sudden decrease of 11-13%, and no circumstances are described in which such a decrease might occur. Indeed, it is hard to imagine a real-world situation that resembles these scenarios, other than the sudden loss of an industrial load.

Scenario c), on the other hand, is somewhat plausible. It can be conceptualized as either a systematic error in load forecasting that results in inadvertently doubling load growth throughout the entire planning period, or (more plausibly) as a portfolio of CDM programs that results in cutting the growth rate in half.

We learn from the first page of Exh. 43, rev. 1 that, under this scenario c), cutting the growth rate in half over the entire planning period would reduce the CPW difference between the two scenarios by almost two-thirds, from $2 billion to $763 million. This is a huge reduction; if coupled with other plausible scenarios, such as cost overruns or fuel price growth lower than forecast, it could certainly contribute to reversing the CPW advantage of the Infeed scenario.

How plausible is this as a CDM scenario? How "aggressive" is an objective of reducing Newfoundland's load growth rate by half?

To help answer this question, we need to refer to the study of the CDM potential in Newfoundland prepared by Marbek Resource Consultants in 2008. It was filed in response to PUB Order PU 8 2007, which required NLH to file it and a five-year plan for implementation of CDM programs in 2008. I would like to enter a copy of the Marbek study into the record of this proceeding.

The summary of the study findings, on page 9, identifies the Upper and Lower limits of Achievable Savings by the year 2026 as 951 and 556 GWh/yr, respectively. This table is reproduced on p. 25 of Nalcor's Submission.

According to the last page of Exh. 43, rev. 1, the 50% reduction scenario would imply a reduction of 453.4 GWh in 2026. In other words, the one plausible CDM scenario explored by Nalcor is only 81% (453/556) of the **Lower** limit of achievable savings for 2026 identified by NLH's consultant in 2008. It can thus be thought of as a model of a **modest** CDM program.

One could argue that these gains are already accounted for in the technological change variable described above, used as part of the base load forecast, but this would be incorrect. If these gains of 35.37 kWh/customer/year have been going on historically, they reflect technological trends that can be expected to continue, not the results of programs that have not even been designed or put into place yet. Thus, a serious CDM program can be expected to produce efficiency gains **over and above** the technological trends observed over the last decades.

Furthermore, there is good reason to believe that Marbek's estimates are conservative, in today's context, for the simple reason that they are based on 2008 avoided costs of 9.8¢/kWh (Marbek, page 4). Given the data currently before us concerning the operating costs of Holyrood, the avoided costs for an updated CDM study would inevitably be much higher than 9.8 cents – probably closer to 15 cents. The higher the avoided costs, the more conservation measures are cost-effective, and the greater the incentive for customers to participate in them. Thus, it is virtually certain that, if Marbek were to update their study today, the Achievable Potential figures would increase.

I conclude from all this that MHI's study **failed to properly take into consideration the impacts on load growth of a properly designed and executed portfolio of CDM programs over the planning period. Had it done so, the CPW advantage of the Infeed scenario would be greatly decreased, if not eliminated, even before considering other sensitivities.**

The fundamental problem here is that Nalcor's generation planning methodology is just that: a **generation** planning methodology. Back in 2007, in P.U. 8, the Board very properly (in my view) found that "an IRP (Integrated Resource Plan) undertaken as part of a generic process as described in Order No. P.U 14 (2004) is an important planning tool and would enhance the information available to the Board and other parties regarding future generation and supply options in the Province." (p. 60).

Earlier on the same page, the Board quotes P.U. 14 (2004) as follows:

> *"...implementation of Integrated Resource Planning may present sound opportunities for coordinated planning and improved regulation involving both utilities. This process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations."*

Indeed, the generation planning methodology used by Nalcor explicitly excludes these last two important elements: demand side management options and environmental considerations. On this last point, I would refer you to MHI-Nalcor-41 Rev. 1:

> The chosen resource plans (generation expansion plans) were selected on the minimization of revenue requirement, modeled as the "minimization of utility cost" objective function. **As there was only one objective function used, its weighting was 100 percent.** There were no objectives tied together as only one objective function was used.

As I'm sure you are well aware, energy efficiency programs are generally measured by a number of tests, the most important of which is the Total Resource Cost test, which measures the total cost to a society, not just the cost to the utility. Thus, unlike the "minimization of utility cost" function, it also takes into account reductions of **customer** costs, resulting from reduced electricity use.

To expand a bit more on this, I would refer you to a recent study by the Regulatory Assistance Project in the US, which states: <u>The goal of an IRP is to identify the least-cost resource mix for the utility and its consumers. *Least-cost* in this case means lowest total cost over the planning horizon, given the risks faced. The best resource mix is typically the one that remains cost-effective across a wide range of futures and sensitivity cases — the most *robust* alternative — and that also minimizes the adverse environmental consequences associated with its execution.</u> (Electricity Regulation in the US: A Guide, RAP, www.raponline.org, p. 73)

I have submitted an excerpt from this study, to be filed as GRK-5.

As for environmental considerations, which play an important role in IRP, they are excluded from the utility's generation expansion planning.

As I understand it, the Board declined to order implementation of an IRP in 2007, in anticipation of the provincial Energy Plan. I am not aware of any progress in that direction in the meantime.

Once again, we must distinguish between a generation scenario optimized on the basis of cost only, on the one hand, and a robust integrated plan, on the other. The Isolated Island Scenario is an example of the former. It constitutes an important input in the development of a plan, but should not be confused with the result.

FUEL PRICE FORECASTS

As time is short, I will keep my comments on fuel price forecasts brief.

I simply want to emphasize that fuel price forecasts are highly uncertain and volatile. I believe that the PIRA high and low forecasts have not been made public, so to get an idea of the extent of the spread between them, I had to look to other sources.

I have reproduced the fuel price forecast from the Northwest Power Planning Council's 2009 Power Plan. (By the way, I strongly recommend the NPPC as a leading reference for integrated resource planning methodologies.)

As you can see, the high scenario shows prices more than twice as great as the low scenario ($120 versus $45 per barrel, in 2030). As MHI wrote in their report, these forecasts have a short shelf life. While they are a necessary evil, it is not a good idea to bet the farm on this year's fuel forecast coming true.

My next document (GRK-6) speaks to the degree of reliability of these forecasts. This is a summary put together by the US Energy Information Agency, assessing the accuracy of its own fuel price forecasts from 1982 to 2010.

Let me summarize the results, which are surprising. The forecasts produced from 1982 to 1985 were way too high – 133% too high, on average. From 1986 to 1995, the forecasts were still too high – by 35%, on average. But for the next 10 years, from 1996 to 2005, forecasts were all too low -- 32% on average.

I find this particularly interesting, not just because it shows the inaccuracy of the forecasts, but because the errors are so systematic. We don't see random variation – we see that forecasters were systematically wrong, in the same direction, for years on end. From 1982 through 1994, they consistently over-forecast oil prices. And from 1995 until today, they have consistently under-forecast prices. What does that tell us about today's forecasts? That there is a very substantial chance that they will be wrong, and significantly so. We just don't know in which direction.

WIND POWER ASSESSMENT

I now would like to turn to the wind power component of the Isolated Island Scenario. In section 11.3 of Vol. 2 (p. 183), MHI explains that it relies on Nalcor's 2004 assessment of the limitations for non-dispatchable generation (exhibit 61), which recommends an upper limit of 80 MW. Surprisingly, MHI provides no analysis or commentary concerning this study. It does, however, affirm that the 80 MW limit is "reasonable".

In its Submission, on page 74, Nalcor explains that this study "established two limits regarding the possible level of wind generation integration on the Isolated Island system, an economic limit and a maximum technical limit." The economic limit is that, in excess of 80 MW, "there would be a significant increase in the risk of spill at the hydroelectric reservoirs," with an additional 20 MW resulting in an increase in expected spill from 9 to 19 GWh/yr, with a cost of $1.3 million/yr. The technical limit could require curtailment of wind down to 130 MW during periods of light load. To avoid incurring these costs, NLH recommended limiting installed wind power to 80 MW.

Obviously, hydro spillage and wind curtailment are to be avoided as much as possible. However, in an economic analysis, it is the bottom line that counts.

So we need to look a little closer. First, let's start with the cost of wind power. The Nalcor Submission, somewhat surprisingly, relies on a pamphlet by the Pembina Institute, an Alberta environmental NGO, to state the cost of onshore wind as 8-10 cents/kWh, pointing out that good wind sites on the island are "at the lower end of this range." In fact, based on data from the Canadian Wind Atlas, we estimated that wind power costs on the Island would be much lower – as low as $66/MWh.

This same dataset suggests that Island wind power would have a capacity factor as high as 45%.

Put together, this means that an additional 20 MW of installed wind capacity would produce 79 GWh a year, at a cost of $5.2 million.

Now, let's accept Hydro's conclusion that doing this would result in increasing spillage to 19 GWh/yr, with a value of $1.3 million, and let's charge that to the wind project too.

That gives us 79 GWh for a total of $6.5 million, or just $82/MWh, net of spillage. Not to be sneezed at, compared to costs of either Muskrat Falls (and associated transmission) or Holyrood.

Of course, it goes without saying that one can't run a power system on wind alone. Backup is essential. Whether such backup would consist of the existing Holyrood plant, a refired Holyrood, or some other combination of resources is not at issue here, since we are limited to examining the Isolated Island Scenario. In a future planning process, I presume these questions will be explored in detail.

As for the technical limit, the Nalcor Submission states that:

> "for wind generation above 130 MW it would not always be possible to maintain system stability particularly during periods of light load and <u>during these periods wind generation would have to be curtailed</u>, again, <u>reducing the economic benefit</u> of the additional wind generation."

In other words, this technical limit is in fact an economic limit as well.

Obviously, wind generators don't like curtailment any more than hydro operators like spillage. Since the energy is free, it hurts to throw it away. But sometimes, system operations require that. In areas with open wholesale markets, wind generators are now frequently required to curtail generation when so required. If new wind generation is economic, <u>taking into account the cost of curtailment,</u> there is no reason to exclude it.

Finally, it is important to mention that the 2004 study made it very clear that it was a preliminary investigation:

> However, given the preliminary nature of this investigation, it would be prudent to further limit the initial quantities of wind generation into the system. Consideration should be given to a stepwise pattern of increased penetration levels over a number of years to gain direct operating experience with the technology and its integration into the Island system. This would allow Hydro to further define the opportunities and constraints associated with the resource without subjecting customers to undue expense or power quality issues. As well it would allow the industry to arrive at possible solutions which, along with the experience gained by Hydro, may permit penetration levels beyond those currently identified.

Indeed, the Government of Newfoundland and Labrador seems to continue to be interested in the possibility of increasing wind penetration beyond the levels identified in the 2004 study. A Request for Proposals was recently issued by the Department of Natural Resources concerning Onshore Wind, in Phase 2 of its Energy Innovation Roadmap process?[1] I would like to enter this document into the record of this proceeding as GRK-7.

For Onshore Wind, one of the areas to be included in the Roadmap is identified as Grid Inflexibility/ Integration. The RFP states (p. 8):

> The ability of the grid to absorb higher penetrations of intermittent wind energy is a function of the flexibility of other generation supply, interconnection, customer loads, and the availability of electricity storage facilities. This is particularly challenging for Newfoundland and Labrador given the absence of these features at the present time.

One of the work products requested is to:

[1] http://www.nati.net/membership/requests-for-proposals/rfp-energy-and-innovation-roadmap.aspx

> “assess the flexibility of the existing generating capacity in Newfoundland and Labrador, particularly with respect to the integration of a significant amount of variable generation (e.g. wind power)”. (p. 9)

The consultant is also asked to:

> “recommend options and technologies that could improve the flexibility of the existing generating facilities;”
>
> “recommend options which could lead to the development of new concepts for the techno-economic integration of high wind penetration systems featuring hydro and gas (possibly) and storage facilities;” and
>
> “recommend options for the development of power management strategies and system designs that are tolerant of high proportions of wind generated power and the consequent fluctuations in energy supply, by providing mechanisms such as storage loads or wide area balancing that provide grid stability despite unpredictable supply characteristics.”

Read together, the 2004 study and the 2012 RFP make very clear that the 80 MW limit is not only preliminary, but also that significant effort is underway to overcome it. While it may be prudent <u>today</u> to limit wind penetration to 80 MW, **it is not reasonable** to assume that this limit will remain in place for the next decade, much less for the next 50 years.

Thus, it is incorrect to conclude that the Isolated Island Scenario includes the economically optimal level of on-island wind generation.

CONCLUSIONS

Normally, I would conclude a presentation like this by suggesting the decision that I would make, if I were in your shoes.

In this case, that is particularly difficult, because of the nature of the Reference Question.

You have been asked whether or not the Muskrat Falls Projects represent the least-cost option, compared to the Isolated Island option, as defined in your Terms of Reference.

On one level, that involves verifying that the costs attributed to each option are correct, and it appears that your consultants have done very thorough work in that regard.

On a deeper level, it also involves verifying that the scenarios make sense – but not going so far as to suggest that they might be changed. This is a delicate line to walk, and I don't envy you your task.

That said, I think that, between MHI's comments, min, and those other commentators, you have ample reason to suggest that, given the many assumptions underlying the Isolated Island Scenario, in particular, and the great uncertainties surrounding these parameters, that that Scenario is unlikely to be realized, as defined in the Terms of Reference. In other words, in the event that the Muskrat Falls project does not go ahead, there is no reason to believe that this particular scenario will ever be put into place.

If the Muskrat Falls projects do not go forward, your planning processes will continue to evolve, and will undoubtedly lead to solutions very different from the one set out in the Terms of Reference.

To me, that means that the Reference Question is largely academic. Even if you were to find that the $2 billion CPW difference between the two scenarios is accurate, that finding is of little significance in relation to the underlying question of whether or not the Muskrat Falls projects are in the public interest for the people of Newfoundland and Labrador.

Source: CAKPL-Nalcor-27 rev. 1
Columns in yellow: P. Raphals

	(1)	(2)	(3)	(4)	(5)	(5a)	(5b)	(6)	(6a)	(6b)	(7)	(7a)	(7b)	(7c)	(8a)	(8b)
	Incremental Costs: Muskrat Falls (MF) + Labrador-Island Transmission Link (LIL)															
	Energy at Soldier's Pd GWH	MF Purchases $000	LITL $000	Total Incremental $000	Total	Nominal Annual Cost $/MWh MF	LITL	Nominal LUEC $/MWh	Nominal LUEC MF $/MWh	Nominal LUEC LITL $/MWh	Real LUEC in nominal dollars $/MWh (incl. losses)	Total annual payments $000	Total MF payments $000	MF payments $/MWh	MF (COS) $000	$/MWh
Reference	(MHI~49.2)	(MHI~49.2)	(Note 1)	(2+3)	(4) / (1)	(2) / (1)	(3) / (1)	(Note 2)			(Note 3)	(1 * 7)	(7a - 3)	(7b / 1)	(3) * CPW(MF)/CPW(LITL)	(8a) / (1)
CPW	21 303	2 682 308	1 758 655	4 440 963				208	126	83	132				2 682 308	
Real	33 608															
2010	0	0	0	0	0						132					
2011	0	0	0	0	0						135					
2012	0	0	0	0	0						137					
2013	0	0	0	0	0						140					
2014	0	0	0	0	0						143					
2015	0	0	0	0	0						146					
2016	0	0	0	0	0						149					
2017	1 811	166 064	267 033	433 097	239	92	147	208	126	83	152	275 272	8 239	5	407 280	225
2018	1 878	175 566	263 292	438 858	234	93	140	208	126	83	155	291 090	27 798	15	401 574	214
2019	1 953	186 252	265 058	451 310	231	95	136	208	126	83	158	308 574	43 516	22	404 268	207
2020	2 019	196 415	255 835	452 251	224	97	127	208	126	83	161	325 059	69 224	34	390 201	193
2021	2 115	209 849	258 160	468 009	221	99	122	208	126	83	164	346 860	88 700	42	393 747	186
2022	2 212	223 883	248 415	472 298	214	101	112	208	126	83	168	371 616	123 201	56	378 884	171
2023	2 378	245 531	244 719	490 250	206	103	103	208	126	83	171	406 638	161 919	68	373 246	157
2024	2 447	257 705	241 032	498 737	204	105	99	208	126	83	174	425 778	184 746	75	367 623	150
2025	2 505	269 099	237 356	506 455	202	107	95	208	126	83	178	445 890	208 534	83	362 016	145
2026	2 587	283 493	241 393	524 887	203	110	93	208	126	83	181	468 247	226 854	88	368 174	142
2027	2 676	299 074	231 230	530 304	198	112	86	208	126	83	185	495 060	263 830	99	352 673	132
2028	2 809	320 236	227 615	547 851	195	114	81	208	126	83	189	530 901	303 286	108	347 159	124
2029	3 025	351 695	224 011	575 706	190	116	74	208	126	83	193	583 825	359 814	119	341 663	113
2030	3 103	367 950	220 420	588 370	190	119	71	208	126	83	196	608 188	387 768	125	336 186	108
2031	3 181	384 734	224 237	608 970	191	121	70	208	126	83	200	636 200	411 963	130	342 007	108
2032	3 258	402 008	213 274	615 282	189	123	65	208	126	83	204	664 632	451 358	139	325 286	100
2033	3 336	419 822	209 721	629 543	189	126	63	208	126	83	208	693 888	484 167	145	319 867	96
2034	3 414	438 197	206 181	644 378	189	128	60	208	126	83	213	727 182	521 001	153	314 468	92
2035	3 483	456 106	202 654	658 760	189	131	58	208	126	83	217	755 811	553 157	159	309 089	89
2036	3 545	473 458	207 510	680 968	192	134	59	208	126	83	221	783 445	575 935	162	316 495	89
2037	3 482	474 395	195 644	670 039	192	136	56	208	126	83	226	786 932	591 288	170	298 397	86
2038	3 548	493 064	192 160	685 225	193	139	54	208	126	83	230	816 040	623 880	176	293 083	83
2039	3 618	512 787	188 692	701 478	194	142	52	208	126	83	235	850 230	661 538	183	287 794	80
2040	3 680	532 031	185 239	717 270	195	145	50	208	126	83	239	879 520	694 281	189	282 527	77
2041	3 742	551 758	191 269	743 027	199	147	51	208	126	83	244	913 048	721 779	193	291 724	78
2042	3 804	572 087	178 380	750 468	197	150	47	208	126	83	249	947 196	768 816	202	272 066	72
2043	3 865	592 988	175 426	768 414	199	153	45	208	126	83	254	981 710	806 284	209	267 560	69
2044	3 927	614 549	171 588	786 137	200	156	44	208	126	83	259	1 017 093	845 505	215	261 707	67
2045	3 989	636 677	168 218	804 896	202	160	42	208	126	83	264	1 053 096	884 878	222	256 567	64
2046	4 051	659 468	175 578	835 046	206	163	43	208	126	83	270	1 093 770	918 192	227	267 792	66
2047	4 112	682 807	161 533	844 340	205	166	39	208	126	83	275	1 130 800	969 267	236	246 371	60
2048	4 174	706 915	158 218	865 133	207	169	38	208	126	83	280	1 168 720	1 010 502	242	241 315	58
2049	4 235	731 704	154 922	886 625	209	173	37	208	126	83	286	1 211 210	1 056 288	249	236 288	56
2050	4 289	755 830	151 646	907 475	212	176	35	208	126	83	292	1 252 388	1 100 742	257	231 291	54
2051	4 343	780 595	160 509	941 104	217	180	37	208	126	83	298	1 294 214	1 133 705	261	244 809	56
2052	4 396	806 039	145 155	951 194	216	183	33	208	126	83	304	1 336 384	1 191 229	271	221 391	50
2053	4 450	832 197	141 941	974 138	219	187	32	208	126	83	310	1 379 500	1 237 559	278	216 489	49
2054	4 500	858 354	138 749	997 103	222	191	31	208	126	83	316	1 422 000	1 283 251	285	211 621	47
2055	4 550	885 209	135 579	1 020 789	224	195	30	208	126	83	322	1 465 100	1 329 521	292	206 786	45
2056	4 600	912 830	146 144	1 058 974	230	198	32	208	126	83	329	1 513 400	1 367 256	297	222 899	48
2057	4 629	937 105	129 309	1 066 414	230	202	28	208	126	83	335	1 550 715	1 421 406	307	197 223	43
2058	4 629	955 847	126 210	1 082 057	234	206	27	208	126	83	342	1 583 118	1 456 908	315	192 496	42
2059	4 629	974 964	123 135	1 098 099	237	211	27	208	126	83	349	1 615 521	1 492 386	322	187 806	41
2060	4 629	994 463	120 086	1 114 549	241	215	26	208	126	83	356	1 647 924	1 527 838	330	183 156	40
2061	4 629	1 014 353	132 576	1 146 928	248	219	29	208	126	83	363	1 680 327	1 547 751	334	202 205	44
2062	4 629	1 034 640	114 066	1 148 705	248	224	25	208	126	83	370	1 712 730	1 598 664	345	173 974	38
2063	4 629	1 055 332	111 096	1 166 428	252	228	24	208	126	83	377	1 745 133	1 634 037	353	169 444	37
2064	4 629	1 076 439	108 154	1 184 593	256	233	23	208	126	83	385	1 782 165	1 674 011	362	164 957	36
2065	4 629	1 097 968	105 241	1 203 209	260	237	23	208	126	83	393	1 819 197	1 713 956	370	160 514	35
2066	4 629	1 119 927	111 025	1 230 953	266	242	24	208	126	83	401	1 856 229	1 745 204	377	169 336	37
2067	4 629	1 142 326	59 364	1 201 689	260	247	13	208	126	83	409	1 893 261	1 833 897	396	90 542	20