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February 14, 2012
(9:35 a.m.)
CHAIRMAN:
Q. Well, good morning everybody. I understand there's no preliminary objections or preliminary issues I should say, but I just wanted to announce that we will be breaking regularly. I was lectured inside about the lack of breaks, so I'm going to be automatically breaking at, I don't know, an hour and a half, two hours. It depends on, I guess, how the questioning goes and a natural point to stop the proceedings. So, I think Mr. Johnson, you're still up, so I'll turn it over to you, sir.
GREENE, Q.C.:
Q. Excuse me for a moment, Mr. Chair. I think there is actually now a preliminary matter that Nalcor would like to address and it has to do with the undertakings that were asked yesterday.
O'REILLY, Q.C.:
Q. There were three, I think, Mr. Chairman. There were three matters that came up yesterday for which undertakings were given

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and I think we can respond to those now. The first dealt with the date when the carbon tax would have been applicable, and I've put on the -- made the Commissioners -- that shows up, that information shows up in Exhibit 101 Muskrat Falls Project, pages 65. Page 65, that's the Navigant report, and I don't know if someone wants to speak to that over there, if we can pull that up? You have copies of it there. And according to the Navigant report, it's 2017.
CHAIRMAN:
Q. Okay, alright.
O'REILLY, Q.C.:
Q. Anyway that's addressed in that exhibit, that question.
CHAIRMAN:
Q. I'd like to look at that, yeah.
O'REILLY, Q.C.:
Q. Okay. The other is what is the cost of -- the incremental cost in going to one in 500 as opposed to one in 150, that issue. The cost is -- Gilbert, do you want to -
MR. BENNETT:
A. It's Gilbert Bennett. Good morning, Mr.

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Chairman, Commissioners. We took a look at the work we did to prepare the estimate for the one in 150 year return period and our view of this is that the cost of going to one in 500 would be in the order of 225 to 250 million dollars. That's a very preliminary estimate, so we'd have to do more analysis to firm that up, but that's a reasonable view at this point.
CHAIRMAN:
Q. And your preference is to look at gas generation as a -
MR. BENNETT:
A. - as the alternative.
CHAIRMAN:
Q. As the alternative.
MR. BENNETT:
A. That's correct.
O'REILLY, Q.C.:
Q. And the third item, Mr. Chairman, was the -- there was a question, I think, by the Consumer Advocate about the comparison of PIRA prices and the National Energy Board prices, whether or not they were comparable, and the NEB prices use inflation adjusted prices. I think

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that's correct, is it?
MR. GOUDIE:
A. It's Steve Goudie. The NEB and the EIA referenced prices in CA-53 would be in constant dollars. I think there's 2008 or 2009 constant dollars. And our Exhibit 4 as filed would be in nominal dollars. So if you compared our nominal dollars to the constant dollars from EIA and NEB, you would incorrectly conclude that there was a great disparity in those forecasts.
O'REILLY, Q.C.:
Q. That's it.
GREENE, Q.C.:
Q. I also had one preliminary matter and it's to deal with the witnesses when they're speaking. I wonder if you could identify yourself, because in looking at the transcript last night, a lot of the comments made by Mr. Humphries or statements made by Mr. Humphries were attributed to Mr. Kean. So I think it would be helpful as you go to speak if you do remember to identify your name each time. Thank you.
MR. JOHNSON:

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Q. Thank you. Good morning, gentlemen. I'd like to sort of take up where we left off yesterday when we were talking about the sensitivity analysis and I guess for the benefit of people who are here present today or people who may be watching on the webcast, could you just briefly explain what the purpose is of the sensitivity analysis in the context of comparing the two options for study before this panel.

MR. GOUDIE:

A. The purpose of the sensitivity analysis is to identify the critical variables that are leveraging our decision making on the investment analysis. So we will try to identify those variables in the CPW analysis that are most important to the results coming out of the strategist generation expansion plans. So we would vary fuel prices. We could vary capital costs. We could vary load and see what the pertinent impacts are on the CPW preference for Interconnected Island.

MR. JOHNSON:

Q. And of course, the reference case preference for the Muskrat Falls Labrador-Island link,

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based on the assumption embedded that we have been working with, is nearly a 2.2 billion dollar preference in 2010 dollars for Muskrat Falls over Labrador-Island link or over the Isolated option. I would like to, if we could, Mike, bring up page 207 of the MHI report, in particular Table 42?

And I guess the first sensitivity that I'd bring your attention to this morning, having visited some of the earlier sensitivities listed there yesterday, is the one numbered eight, being the Labrador-Island HVDC link and Muskrat Falls capital cost increased by 50 percent. So in other words, if we were to increase the present estimates for the Muskrat Falls and Labrador-Island link scenario by 50 percent, we would see an evening out in the preference between the two options. There still would be a nearly 200 million dollar preference for the Muskrat Falls Labrador-Island link scenario. And I guess, at that stage, it's more of a comment for people who are watching these proceedings when they see a possibility of the preference being largely erased under that scenario,

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could you just give a comment to us about the thinness of the preference if we change the assumptions to that extent?

MR. GOUDIE:

A. This is Steve Goudie. That sensitivity represents a 50 percent increase in the in-service capital cost of the Muskrat Falls generation investment and the Labrador-Island link. It is the leverage in the analysis, so if those two major capital components did increase by 50 percent, the CPW preference for the Interconnected alternative would begin to approach zero.

MR. BENNETT:

A. It's Gilbert Bennett. Maybe I can add to that. I think the question though that has to be considered is the likelihood of that scenario.

MR. JOHNSON:

Q. That's what was I -

MR. BENNETT:

A. Okay. So, you know, the risk, yes, if you do the analysis, you increase the capital cost by 50 percent, that is the analytical outcome, but the question that begs itself is what's

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the likelihood of that and what steps are we taking in order to minimize that situation.

MR. JOHNSON:

Q. Right, right. And I guess we could plug in whatever number we wanted to this and it'll produce a mathematical result. What -- from Nalcor's standpoint, what -- if we look at, you know, a range, let's say the textbook range around DG2, should we use a high sensitivity test? Is that instructive to us? Is that the one we ought to use in your judgment?

MR. BENNETT:

A. I think from my perspective, the sensitivity analysis has demonstrated a sensitivity on capital cost and then I think, you know, from our perspective, the steps to be taken would be to mitigate that exposure. So, you know, it comes back to all of the techniques and approaches that Mr. Harrington and Mr. Kean described yesterday in order to narrow in that range and to mitigate and diminish that sensitivity and that concern.

(9:45 a.m.)

MR. JOHNSON:

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Q. If we look at scenario nine, again another thin outcome, and perhaps not an outlandish scenario whereby we would be assuming that over the long run the fuel costs would decrease by 20 percent, annual load growth would decrease by 20 percent as well on top of that and then the third whammy, if you will, you'd have the capital cost increasing for Muskrat Falls generating station and the Labrador-Island link by 20 percent and we arrive at a preference of about 159 million dollars in 2010 dollars for the Muskrat Falls option over the Labrador-Island link. Just comment on that scenario, in terms of -- put some commentary around that scenario.

MR. BENNETT:

A. Sure. Well, I think, you know, one observation that I would make is that we look at other situations that are also reasonable and should be considered. If you're doing this analysis at DG3, we would have a clearer view of the Federal loan guarantee. We know the Federal loan guarantee diminishes the CPW of the Interconnected alternative. A current fuel price forecast would improve the CPW

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preference for the Interconnected Island alternative as well. So, I think that, again, the importance and value of the sensitivity analysis is to give us a basis for further analysis and to highlight and identify the areas where we need to focus attention. That as a predictive tool, their usefulness is limited because we're dealing with our earlier analytical inputs. So, in terms of highlighting areas for focus, they're absolutely valuable. In terms of identifying the areas where we need to do more work and to further advance and define the numbers, they're extremely valuable, but the next step in this process will be to look at the numbers at a later stage, at Decision Gate 3, where you have further clarity on all the input information.

MR. JOHNSON:

Q. You referenced the guarantee and just explain for those who may be looking on what role that plays in the sensitivity analysis. Why is it that that changes or has a bearing upon the preference?

MR. BENNETT:

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A. The fundamental value in the Federal loan guarantee is to reduce the cost of financing and therefore the interest expenses included in the generation assets and the transmission facilities.

MR. JOHNSON:

Q. And the underlying reason being that Canada's credit rating, being AAA, allows access or their standing behind the project allows the borrowers for the project to get access to cheaper funds?

MR. BENNETT:

A. They have a -- yes, they have a strong credit rating, there's no question.

MR. JOHNSON:

Q. At DG3, I believe -- in terms of the status of the guarantee, at DG3 -- in DG2, up 'til DG2, it wasn't -- it was a possibility because the commitment had not been yet announced by the Prime Minister. Now several months ago, the commitment was announced. How will that change your using that as an input at DG3?

MR. BENNETT:

A. I think it -- at the next stage of analysis, we will have further insight in the terms of

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the loan guarantee and we'll be in a better position to specifically identify the financing terms, the financing and commercial parameters that we're using for the project and we'll have much greater clarity in that input.

MR. JOHNSON:

Q. Finally, the final thin scenario, as we go down to scenario ten, where we assume an annual load decrease of 880 gigawatt hours and then we assume on top of that that the capital cost associated with the Muskrat Falls generating station and Labrador-Island link cost increase by ten percent, again, your commentary on that sensitivity.

MR. BENNETT:

A. I mean, my perspective is exactly the same as it was for number nine. It's a good analytical tool. It's valuable input. It highlights the areas that we need to focus attention on, but again, it doesn't include the benefit of the Federal loan guarantee, nor does it include the cost of carbon.

MR. JOHNSON:

Q. In terms of looking at the base case estimate

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of the Isolated Island option, which is right up at number one, on top of the chart there, it has a cumulative present worth of 8.8 billion dollars and I guess my question would be are there -- in Nalcor's assessment, are there areas where Nalcor has been conservative in relation to costs or factors that impact upon the CPW preference or the CPW of the Isolated Island option? I'm trying to get a sense of, you know, were you conservative in any of your inputs on that?

MR. BENNETT:

A. I think our efforts were -- I would characterize them as reasonable. We've used reasonable inputs, reasonable forecast information and the results are as they're presented. I wouldn't call them conservative. I wouldn't call them optimistic. I think they're reasonable.

MR. JOHNSON:

Q. Okay. I just wanted to get a sense of that, in terms of our looking at it, whether we should say well, Nalcor said that was conservative. But I guess the point that you made a second ago was that it doesn't include

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certain costs pertaining to possibilities of greenhouse gases, okay.

MR. BENNETT:

A. That's right.

MR. JOHNSON:

Q. In terms of the industrial load forecast, we spoke about that a bit yesterday and I think there were some updates to load projections in the case of some of the industrial customers and I was interested in knowing whether there had been an update in relation to Vale's load since the reference case.

MR. BENNETT:

A. Turn to Mr. Paul Stratton here for this one.

MR. STRATTON:

A. It's Paul Stratton. We do have an update on the peak requirements from Vale, but they did not provide us any energy requirements update to the forecast. So from that point of reference, their demand requirement is modestly down, but we would expect their energy requirements to be at the same load factor that it would have been in the earlier cases.

MR. JOHNSON:

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Q. So not a -- so is the takeaway not a material difference?

MR. STRATTON:

A. It would not be material, so low forecast.

MR. JOHNSON:

Q. Under the reference case, when is our -- if things pan out in accordance with the assumptions in the reference case, when is our next energy deficit?

MR. HUMPHRIES:

A. It's Paul Humphries. Our next energy deficit will be in the 2020 time period.

MR. JOHNSON:

Q. 20?

MR. HUMPHRIES:

A. Around 2020.

MR. JOHNSON:

Q. And how about capacity?

MR. HUMPHRIES:

A. We are predicting a capacity shortfall for 2015.

MR. JOHNSON:

Q. If we were to assume that overnight we lose 880 gigawatts of load, I guess, in 2013, what would that do to our next energy deficit and

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next capacity deficit?

MR. HUMPHRIES:

A. Well, if that were to happen overnight, both of those deficits would change. They would move out into the future. What the exact dates are I wouldn't be able to tell you right now, but they would not be 2015 and 2020.

MR. JOHNSON:

Q. Okay.

GREENE, Q.C.:

Q. I wonder if you would be able to provide that information? That is one of the areas that I had hoped to ask as well.

MR. HUMPHRIES:

A. Yes, we should be able to provide that.

MR. JOHNSON:

Q. Okay. In relation to the in-feed option, as described in the reference, what is the role of Upper Churchill power?

MR. BENNETT:

A. In the current reference case, we use power from Churchill Falls I think beyond the 2057 time frame.

MR. JOHNSON:

Q. And what's the reason why we would need it

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beyond 2057?
MR. BENNETT:
A. At that point I think we see a small energy shortfall with the energy supplied from Muskrat Falls.
MR. JOHNSON:
Q. I guess a question that was put to me yesterday was what would be the role of Upper Churchill prior to that or you know, the major date of 2041. I don't know if that's -- obviously 2041 is not within the two strategist scenarios, but I guess people would be interested in knowing why we're waiting until 2057 for it, I guess.
MR. BENNETT:
A. Well, if Muskrat Falls is in the -- is available for the supply and the supply can be met from Muskrat Falls, then we have sufficient energy supply from that facility and we don't need additional energy on the Island system until the 2057 time frame.
MR. JOHNSON:
Q. A follow up question from a customer who was watching the proceedings yesterday had to do with Nalcor yesterday advised that the

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Maritime link would provide 475 megawatts of backup energy for Newfoundland if there was an outage on the transmission line from Muskrat Falls and the question goes on to say that Nalcor also said that Muskrat Falls would proceed without a Maritime link. So the question is if no Maritime link, what is the backup plan for the island?
MR. HUMPHRIES:
A. This is Paul Humphries. As we indicated yesterday, based on the analogy I went through yesterday with the actual exposure that we would have in the event of a loss of the link and the probabilities of being there, we feel that from a probabilistic perspective, we would be in a situation no different than we are today and we would not need additional backup beyond the capacity on the island, but we also in the opportunity of should it be deemed that additional backup is required, we could add additional combustion turbine.
MR. JOHNSON:
Q. The next question I have is: as you know, in the MHI report in relation to fuel price forecasting, MHI makes some commentary about

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reference price versus expected price and I wonder if Nalcor has any observations with respect to possible use of an expected price as opposed to a reference price?
MR. GOUDIE:
A. Yes, this is Steve Goudie. We certainly did review MHI's review of that. PIRA does provide -- well, we subscribe to two services from PIRA Energy. One is the basic oil retainer service and in addition to that, we subscribe to the scenario planning service and it is that service that gives us the high and low and the expected pricing. We don't get that from the basic service. Their high and low pricing is very, very useful for us because it identifies again the leverage that fuel has in the isolated island case, and the sensitivities are one way of addressing what the uncertainty of fuel is, it's a key to address the uncertainty of fuel. The use of an expected forecast which is a weighting of the low and the reference and the high is a proper way to proceed if you're addressing uncertainty from a statistical point of view. So when we come to do our basic analysis for

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interconnected island, we can use a reference price forecast or we can use the expected. The expected has a higher low run price than our reference forecast, and that's why the MHI result shows that if we use an expected as opposed to a reference, the preference for the interconnected island will increase by a substantial degree.
(10:00 a.m.)
MR. JOHNSON:
Q. Okay, do you know the amount by which you would increase if you used that methodology?
MR. GOUDIE:
A. It is in the MHI Report. There's a Table - I don't have it exactly, but it basically goes from 2.5 to - the preference would go from 2.5 to about 2.6 billion dollars, I believe.
MR. JOHNSON:
Q. That's at Table 41 at Page 205.
MR. GOUDIE:
A. Yes, you can see there that if you use the expected fuel prices as opposed to reference, that the CPW preference increases to 2.6 billion from 2.2 billion.
MR. JOHNSON:

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Q. Okay, and the weightings, I understand that - in the two paragraphs up from that table, MHI says, "The impact on the CPW using the expected price rather than the reference price was examined based on the March 2010 forecast, the prices provided by PIRA set out on Page 10 of 37 in Exhibit 43, an assumed weightings of 50 percent/25 percent/ 25 percent, the resultant expected prices are higher than the reference prices". These assumed ratings, can you fill us in on what - or assume weightings, can you fill us in on what that means?

MR. GOUDIE:

A. The weightings would be PIRA's assessment of the likelihood of those scenarios. I don't believe they characterize them as assumed weightings. I think they characterize them as probabilities.

MR. JOHNSON:

Q. So the 50 percent probability, that would be their -

MR. GOUDIE:

A. The reference.

MR. JOHNSON:

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Q. That would be their best assessment, and then 25 percent would be the high, 25 percent would be the low?

MR. GOUDIE:

A. That's correct.

MR. JOHNSON:

Q. Okay. I'm going to turn to a slightly different topic having to do with HVDC system losses. If we could bring up page 206 of the MHI Report. At Section 12.20, MHI says that "Nalcor assumed HVDC system losses are set at 5 percent. However, there is reason to believe they could be higher based on a response to RFI NHI Nalcor 62. If the loss percentage is 10 percent, which is Nalcor's worse case design scenario, then there will be higher transmission losses associated with the Labrador-Island Link HVDC system when operating at capacity. An incremental increase of 5 percent of system losses may result in the addition of 150 million dollars to the CPW cost for the in-feed option". First just to start off, just explain to us what we're talking about when we're talking about transmission losses?

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MR. HUMPHRIES:

A. This is Paul Humphries. Transmission loss, that is the - because of the resistive nature of a transmission system, there is a loss generated through the transmission, so that at the end of the day you will get less power out of the end of the line than you put in at the beginning.

MR. JOHNSON:

Q. Okay, and that would be a concern particularly over long distances like 1100 kilometres?

MR. HUMPHRIES:

Q. Over the long distance, yes, and also on the level of load on the line, as losses increase proportionately with the loading on the line.

MR. JOHNSON:

Q. Okay, and in terms of the HVDC, is that - is HVDC over AC technology better for losses or is there any - does it have any bearing on it?

MR. HUMPHRIES:

A. Generally HVDC has a better loss performance than AC.

MR. JOHNSON:

Q. And how would these losses translate into having an effect on the CPW for the options?

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MR. HUMPHRIES:

A. Well, if the losses are higher than were anticipated in the analysis, you are actually getting less energy from the line. So that has to be made up from another source.

MR. JOHNSON:

Q. Okay, and I guess what is your comment about the possibility that transmission losses could be higher as stated by MHI?

MR. HUMPHRIES:

A. At periods when the link is operating at full capacity, the losses will be higher, but on an average, they will be closer to the 5 percent range than they are to the 10 percent overall average loss, based on the anticipated loadings of that line.

MR. JOHNSON:

Q. And is there any dispute with the mathematics of MHI that if they're 10 percent, then it does add 150 million, or has that been checked?

MR. HUMPHRIES:

A. I'm not sure that we've verified that.

MR. GOUDIE:

A. The way that - Steve Goudie, sorry. The way

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that we would probably have looked at that is if the loss rate had have been 10 percent from the start as an input to our analysis, then the amount of energy being delivered from Labrador would have been greater, and given a defined rate of return for the Muskrat Falls Project, we would have reduced the supply price from the $76.00 per megawatt hour to something a little bit lower because that price is set at the busbar, it depends how much power is going out - how much energy is flowing out.

MR. JOHNSON:

Q. Okay, when will you know or have a - as I understand your reply to a Board question, which is for the record, PUB 84, Nalcor advised that transmission losses will be evaluated further in conjunction with conductor, converter, and transmission optimization during detailed engineering prior to project sanction, and could you advise us, inform us, as to how you will get a better handle on what those transmission losses will be in conjunction with those processes just described?

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MR. HUMPHRIES:

A. Well, as we progress with the design and specification and tendering of these particular elements, be it the converter station equipment, transformers, and the transmission line, we will know the exact components that go in there and we will have a handle on the physical impedances of these systems and we will be able to do a better estimation of the losses, more accurate estimations.

MR. JOHNSON:

Q. Is there a likelihood that there could be as high as 10 percent losses? You know, is that in the cards?

MR. HUMPHRIES:

A. Close to 10 percent, yes, that could be if the line is at full peak load, but we have to realize that the line will not - when we look at Muskrat Falls, Muskrat Falls is an 824 megawatt facility with approximately 60 percent capacity factor. It is not possible for Muskrat Falls to load that line at 824 megawatts 24 hours a day, 365 days a year.

MR. JOHNSON:

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Q. Okay, and that's where those maximums would be reached?

MR. HUMPHRIES:

A. Yes.

MR. JOHNSON:

Q. I have a question regarding oil. It's addressed in Section 12.10 of the MHI Report. It's basically inventory. That's at page 197. Just to get your comment and try to understand this, it indicates that, "Nalcor did not include the carrying cost of fuel inventory, which is normally part of the rate base component used in determining the cost of service for the utility". MHI goes on to say, "In the current comparative analysis of CPWs, the value of fuel inventory would only be significantly different between the two options in the period where Holyrood is no longer generating base load power which exists mostly from 2017 and on. If fuel inventory carrying costs were included in the CPW analysis, the consequence would be an increase in the CPW for the isolated island option, and accordingly would serve to further increase the gap between the two CPW values". I guess

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my question is, is that a material enough figure to worry about, is there any significance to that number?

MR. GOUDIE:

A. That cost is accounted for once we move out of the Strategist framework and into the revenue requirement framework. So it's not a cost that's accounted for directly in Strategist, but it is a cost that's accounted for when we take the Strategist output and begin to build the total revenue requirement for the company, and that is - to your question, it is not a material cost.

MR. JOHNSON:

Q. Okay. If I could turn you to page 187, Section 12.4 of the MHI Report. This is a discussion of the Muskrat Falls PPA, and it basically indicates, "That the premise supporting the use of a PPA approach relies on the base assumption that Newfoundland and Labrador Hydro will sign a take-or-pay contract with Nalcor for the specified Newfoundland and Labrador Hydro energy purchases from Muskrat Falls that Strategist has projected. As equity owner of the Muskrat

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Falls Project, Nalcor will eventually receive its target return on the investment over the life of the asset based on the volumes consumed", and then it goes on to explain that, "To determine the PPA prices, it was assumed that all firm output 4.5 terawatt hours generated by the Muskrat Falls generating facility would be sold. Then the internal rate of return would be 11 percent and equity financing would be 100 percent. These assumptions resulted in a price of approximately $76.00 a megawatt hour in 2010 dollars, escalated at 2 percent in nominal terms". Could you for the purpose of people who are watching this webcast tell us the difference between PPA and cost of service because in another section MHI talks about if there's any difference in CPW terms when using the PPA in the cost of service? Just explain the PPA and why it was chosen?

MR. GOUDIE:

A. I guess if we start with the cost of service framework because we're all - or some of us are more familiar with that, if we bring the Muskrat Falls investment into a cost of

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service framework, then the revenue requirement is not dependent on the output sold from the facility. So in the first year of following in service, the revenue requirement will be a function of its depreciation charge and its return on rate base. So 100 percent of the net book value of that plant will be subject to a cost of service calculation in year one. By contrast, with a PPA approach, instead of the focus being on the net book value of the asset as it goes into service, you're focused on the internal rate of return or the return on equity over the life of the project, and the advantage for consumers is that following a PPA approach, your initial pricing will be lower, plus it will be constant in real inflation adjusted terms. By contrast with a cost of service approach, you're going to have very high initial unit charges because we cannot absorb all of the output of Muskrat Falls onto the island system. We only require about 40 percent of it in the first year. So the unit charge of that will be very, very high.

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MR. JOHNSON:

Q. So under cost of service, if it was all lumped in to rate base, cost of service wouldn't care how much the customer was actually taking out of generating facility by way of energy, it would just be charging - they'd have to collect the cost of that generating facility through the rate no matter what you took?

MR. GOUDIE:

A. That's correct. So irrespective of output, that cost would have to be collected once it's rate based.

MR. JOHNSON:

Q. Okay, and in terms of that model, how did you fix upon that sort of model, how did that come within the contemplation of Nalcor?

MR. GOUDIE:

A. Well, that would have been something that we work through with our financial advisors because essentially when you move to the PPA approach, you're really focused on cash flow and you're not focused on net book value of the asset. All that matters is cash and being able to meet your obligations and meet a threshold or hurdle return across the period

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of time that you're evaluating, given the output of the plant that's being sold to the island.

(10:15 a.m.)

MR. JOHNSON:

Q. So in terms of - you use the example or you made reference to the fact that if you were going with a cost of service approach, given the fact that the customers on the island would not be taking the full Muskrat Falls power for a number of years out, that the impact on the customer would be great, I take it?

MR. GOUDIE:

A. That's correct.

MR. JOHNSON:

Q. And so if we did it that way, what would we be talking about in terms of the amount that would have to be charged for generation, say?

MR. GOUDIE:

A. We have answered that question in an RFI for the PUB. I think it's PUB 46. So the question was if the cost of service pricing were applied in determining the power of purchase price, what would be the power of

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purchase price paid by Hydro to Nalcor from Muskrat Falls power and energy in the first calendar year supply, and the answer to that is that it would be $214.00 per megawatt hour in the first year.

MR. JOHNSON:

Q. And so that would be on a per kilowatt hour charge, 21 cents, basically. You make the point there that it would decline each year thereafter as the island sales base grows and the return on rate base declines. Just explain that?

MR. GOUDIE:

A. The Labrador-Island link is funded on a cost of service basis, or it's analyzed, I should say, on a cost of service basis. So in the early years of the transmission link, the revenue requirement reflects the high net book value and as that asset is depreciated over time, the return on rate base applies to net book value, which is book value less depreciation, and that return on rate base will decline over time as the asset is depreciated. So, therefore, the cost of service on the Labrador-Island transmission

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link will decline.

MR. JOHNSON:

Q. Okay, and -

MR. GOUDIE:

A. Actually, no, I'm sorry, I'm talking about the Labrador-Island transmission link. I should be talking about Muskrat Falls, sorry, but it's the same principle.

MR. JOHNSON:

Q. Same principle, okay. There was a question that was posed by a customer was what would be the - what would be or what is the incremental standalone kilowatt hour cost of Muskrat Falls power all the way to Soldiers Pond under - I guess under that - I guess that's the question that's basically posed in #27, I believe.

O'REILLY, Q.C.:

Q. Yeah, and I think we indicated - Mr. Chairman, just to step in here, there was a response to that question that was filed in CA-27, I think it was, 27 or 28, and there was some issue about whether or not that would inform - the answer to that would inform this process, but there seems to be a lot of curiosity about the issue, and so we agreed yesterday with the

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Consumer Advocate that we would file a revised answer to that dealing with that, and we're hoping to have that sometime today, and I've indicated that, so that we will have a revised RFI filed on that question, that should be ready, and then if there's a question that comes out of that, well, fine, we can deal with it, but we would like to refile the RFI.

MR. JOHNSON:

Q. Okay.

O'REILLY, Q.C.:

Q. Is that satisfactory?

MR. JOHNSON:

Q. Okay. Now regarding DG 3, I just want to look ahead a little bit, we heard yesterday that there is going to be a review of all DG 3 inputs at that Decision Gate stage, and an updated CPW analysis, and as well there's going to be updates as relates to the various reliability issues that we canvassed yesterday, whether it be integration, etc. What is planned in terms of having that reviewed, let's say, to make sure that it's all copasetic, what sort of processes will that be worked through?

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MR. BENNETT:

A. Certainly within - this is Gilbert Bennett. Within Nalcor, we will subject our internal analysis to review by consultants within our own Decision Gate process. Our CEO, Ed Martin, who is the gatekeeper of that process may request reviews within our own internal context, and I guess I can't comment on what might happen beyond that if anything.

(10:31 a.m.)

MR. JOHNSON:

Q. I think it might be a space now where I'm going to have to consider if I have anything left. I just want to check notes, Mr. Chairman, if I could.

CHAIRMAN:

Q. We shall break. I'm not even asking you all, we're just going to break.

(RECESS)

(10:48 a.m.)

MR. JOHNSON:

Q. I think, Mr. O'Reilly, you have a point to make.

O'REILLY, Q.C.:

Q. Yes. Mr. Chairman, Mr. Stratton, who spoke

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previously in response to a question from the Consumer Advocate on the projection for the Vale load, he'd like to make a correction to his previous response, I think, so he's sitting in the chair there and would like to address that.

CHAIRMAN:

Q. Sure.

MR. STRATTON:

A. Paul Stratton. I just want to clarify what my statements that were made previously that with respect to the Vale load being lower or higher based on a set of numbers that were provided to us recently, and with respect to the Vale load requirement that was included in our DG 2 analysis, the new power requirement provided to us from Vale are modestly higher, not modestly lower, and my earlier statements were with respect to an interim number that was provided to us last spring, but, of course, were not included in the DG 2 analysis. The end result of that the requirements are modestly higher and that would improve the preference for the island link.

MR. JOHNSON:

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Q. Okay. Perhaps what we could have is just confirmation of the change in terms of what was in the reference case and what it's now, so we're dealing with some harder numbers maybe.

MR. STRATTON:

A. Yes, that can be provided, yes.

MR. JOHNSON:

Q. Mr. Chairman, I don't have anything further for the panel at this stage. However, I would say there may be something arising from Board Counsel's questions that I might wish to pursue further. As well, just for the benefit of people who may be watching and providing me email questions, you know, some of them are coming in early in the morning and at night time, I'm going to get those together and file them in the proceeding pursuant to my role for Nalcor to answer. There are some further outstanding questions because there's been a number of questions, a good number of questions asked in recent days, which not unexpectedly have not been answered as yet, so we're going to have a meeting of counsel to determine where we are on that, and what the

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schedule will be around that. So I just want to let people know that I'm getting the messages and they'll be put on the record.

CHAIRMAN:

Q. You're listening.

MR. JOHNSON:

Q. I'm listening.

O'REILLY, Q.C.:

Q. Mr. Chairman, that's fine, and we can discuss that - counsel will discuss it, appreciating the fact that most of the questions up to February 6th, I think, was the last bunch that remain outstanding, but leading up to the preparation for this, it's just been trying to get the resources to get all these answers together and get them filed, and we're working on it - we have a status report to the Board last Friday and to counsel as to where we were and when we expect it. These additional ones that you're getting now, of course, will go in the pile to be dealt with, but, you know, there's a limit to the resources we have available, particularly while these proceedings are going on at the same time. We're endeavouring to do it. We'll work it

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out.

CHAIRMAN:

Q. Okay, thank you. So Madam Greene, I think it's your turn.

GREENE, Q.C.:

Q. Thank you, Mr. Chair. Good morning, gentlemen. I'd like to follow up first with one of the questions that Mr. Johnson asked just before the break, and it concerns power from the Upper Churchill Power Plant. In responding to the question, Mr. Bennett went to the power and energy built into the analysis that would come in in 2057. I'd like to discuss the availability of Upper Churchill power prior to that because that is one of the issues that has been raised as to why can't the province wait until 2041 when it will access to Upper Churchill power, and I just wanted Nalcor to have the opportunity to be able to respond to that question, and I'd like to bring Mr. Bennett to MHI Nalcor #3 where that question was asked by the Board. Could you bring up that RFI, please, Mr. McNiven. So Mr. Bennett, with this as a reference, can you explain why it is not economic to wait until

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2041 to access the Upper Churchill power?
MR. BENNETT:
A. Yes, thank you. So there are a couple of considerations here. First of all, from an economic perspective, I guess, if we look at waiting until 2041, the Holyrood facility would continue in service for another 30 years approximately from today, we would have to install scrubbers and precipitators on that facility, we would still continue with our thermal expansion plan until 2041. So in looking at the economics, the outcome of our analysis was that there would be a substantial premium from an economic perspective to maintaining an isolated scenario until 2041, and then interconnecting at that point in time.
GREENE, Q.C.:
Q. If you'd turn to page 3 of 3 to that answer, on line 17 to 20 we see the impact on the CPW analysis. Could you please explain what that would be, Mr. Bennett?
MR. BENNETT:
A. Well, what we're doing here is looking at the cost on the system between now and 2041. We

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have the thermal expansion plan in there, so the scrubbers and precipitators at Holyrood, #6 fuel oil, are continued in this plan until that point in time. From there, a comparison to the interconnected plan, we would then interconnect with Labrador and we would import energy from Labrador to the island. Now one consideration in there is the price reference that's used for that supply, and I guess from a broad perspective, there are two ways that energy could flow. That energy could flow into the market post 2041 because the power contract will have expired, or we can move it to the island. In both cases, that energy has value and we've used that value in our analysis.
GREENE, Q.C.:
Q. So one of the primary reasons is the requirement to burn fuel at Holyrood or another oil fired plant until such time as that power would be available, the cost of that makes it uneconomic and is a major factor in the CPW analysis?
MR. BENNETT:
A. That's correct.

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GREENE, Q.C.:
Q. Okay. One additional question related to that is concerning the amount of recall power still available from the Upper Churchill power contract. What consideration has been given by Nalcor to bringing in the remaining available power over the transmission link when it is built?
MR. BENNETT:
A. There is a small amount of capacity of power available from Churchill Falls in the peak winter season, but at this point in time with Muskrat Falls delivering 4.9 terawatt hours to the system, we have more than sufficient energy from Muskrat to meet our needs here on the island.
GREENE, Q.C.:
Q. In terms of the power policy and the Electrical Power Control Act for least cost power, have you considered whether the recalled power would be a lower rate and a lower value than Muskrat Falls power, and whether under the power policy that should be the first to be brought over the link?
MR. BENNETT:

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A. Well, if the link and Muskrat Falls are looked at in tandem or together as a combined supply and transmission facility, then Muskrat Falls at the outset has the ability to meet all of the needs and the marginal cost of Muskrat Falls energy at that point in time will be zero.
GREENE, Q.C.:
Q. But in terms of the cost of the remaining recall, would that be a lower cost than the Muskrat Falls power?
MR. BENNETT:
A. I suppose you could look at the 80 megawatts that's available in the winter, but the question is if you only look at that 80 megawatts, you haven't created a business case for the transmission link. So, therefore, there's no way to get it here.
GREENE, Q.C.:
Q. No, and I - if the link is already built, the question is who should have - is Nalcor considering providing the remaining recall power at the lower rates available if it's cheaper and selling the more expensive Muskrat Falls energy west?

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MR. BENNETT:
A. I guess, at the end of the day when you look at the total value, the value is available on a consolidated basis from either source.
GREENE, Q.C.:
Q. And that has not been factored into the analysis?
MR. BENNETT:
A. That has not been factored into our analysis.
GREENE, Q.C.:
Q. I'd like to turn now the Decision Gate process, and we did have discussion around that yesterday, and we did hear yesterday the difference between Decision Gate 2 and Decision Gate 3, and how Nalcor has used or chosen the Decision Gate process to assist as it moves forward with the development and I will not go through that ground again, but there was some follow up from Mr. Johnson's questions where we still have some uncertainty with respect to some of the areas that were covered yesterday. The first thing I wanted to talk about is the Decision Gate 2, which is the point that Nalcor has passed, it was the point where project selection to proceed

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further to detailed engineering, is that correct?
MR. BENNETT:
A. Yes, that is correct.
GREENE, Q.C.:
Q. And the Decision Gate 2 decision was made in November of 2010, is that correct?
MR. BENNETT:
A. Yes, it is.
GREENE, Q.C.:
Q. And the capital cost estimates that were used in the CPW analysis that was completed and filed with the Board were actually done as of August, 2010, is that correct? We can go to PUB Nalcor 39.
MR. BENNETT:
A. I was looking for confirmation from either Jason or Paul, but my understanding is that's correct.
GREENE, Q.C.:
Q. Yes, and if you'd like to go check, Mr. Bennett, we can take a moment. It's PUB Nalcor 39.
MR. MCNIVEN:
Q. Is that Revision 1?

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GREENE, Q.C.:
Q. Revision 1, yes. It's just a confirmation of the capital cost estimates. So we see there in line 9 to 10 -
MR. KEAN:
A. Yes, that is correct, they were prepared in 2010.
GREENE, Q.C.:
Q. So the information on the project cost estimates that's before the Board were finalized and completed as of August, 2010?
MR. KEAN:
A. Yes, that is correct.
GREENE, Q.C.:
Q. In looking at Decision Gate 2, which used the capital cost estimate that we have from August, 2010, we had some discussion yesterday as to what that meant for a project definition, and yesterday, I believe, Mr. Harrington indicated that, and possibly Mr. Kean, but that certainly at Decision Gate 2 the degree of project definition is less than at what you're anticipating for and chosen as Decision Gate 3. So the degree of project definition is less at Decision Gate 2 in

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comparison to Decision Gate 3, is that correct?
MR. KEAN:
A. Yes, that is correct.
(11:00 a.m.)
GREENE, Q.C.:
Q. And yesterday Mr. Harrington indicated it would be approximately 5 percent, and I wondered if you - I'd like him to comment on that today. The amount of project definition that one could typically expect to see at Decision Gate 2 is what percentage?
MR. HARRINGTON:
A. Well, the AACE standard, which I hope someone can help me out -
MR. KEAN:
A. Jason Kean. Typically the amount of definition is driven by the amount of engineering done is a typical factor in that regard, and for a Gateway Phase 2, which is typically called Front End Loading Phase 2 in the industry, it's somewhere in the range of 5 to 10 percent, depending on the type of project and the new technology employed or not.

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GREENE, Q.C.:
Q. And the project definition is one of the key factors in developing the project cost estimate, is that correct?
MR. KEAN:
A. Yes, the project definition is one of the key aspects. However, there are several other aspects.
GREENE, Q.C.:
Q. But presumably you need to know what your project is to be able to determine what the cost will be to build it, is that correct?
MR. KEAN:
A. Yes, that is correct.
GREENE, Q.C.:
Q. Yesterday we also talked about the range that we associate with a Decision Gate 2 estimate, and the AACE Class 4 estimate which is the standard and which has been applicable for Decision Gate 2, I think it was indicated the range is to a +50 on the high side, to a range of -50 on the low side. That is the range for DG 3 Class 4 estimate?
MR. KEAN:
A. The range for a DG 2 estimate as per AACE

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recommended practice, 18R 97, is in the range of - for a wide range of industries, -50 to +50. However, we did as part of the overall evaluation of the cost estimate for the project, as in our submission in November, stated that we went through a risk analysis in June 2010, which gave us much greater clarity on what the actual accuracy was.
GREENE, Q.C.:
Q. Okay. I guess, perhaps we went to the range, and again it's really not - I'm not looking for a specific number from you, but I guess one of the issues yesterday, Mr. Johnson in talking about the range, which is the range expressed by the international standard which is a broad range, then brought you to your view of the range for the current DG 2 estimate that you have used. In looking at the transcript, and I just wanted to have some clarification around it today, because in reading it and listening yesterday there was a little bit - I was confused or left with some confusion as to where you actually were with your view of your range, what you think Nalcor's estimate is within that range. We

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know what the standard is, which could be as high as 50 percent to the extreme on one side, and the question is, having worked with the DG 2 classed estimate, where you feel that you fall within that range of the standard, and without reading the transcript, and we can if you'd like me to, but I guess to paraphrase it, I think - and Mr. Harrington acknowledged in replying to the question that Mr. Johnson was pushing him a little bit, but that if he would be in the range of 15 to 20 percent if - he thought you were closer to the middle of the range versus the extremes, and I just wanted to follow up with you today on that.
MR. HARRINGTON:
A. Paul Harrington. Okay, I wish to clarify your question there. Within the standard that you've quoted, AACEI, there's the wide range of +50 to -30, but they also quote +20 to -15 range as well. So that's the narrow band that they're talking about, and I think in my testimony yesterday, I indicated I thought that we were closer to the narrower range. Does that answer your question?
GREENE, Q.C.:

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Q. Yes, and I guess in fairness to - probably we should go to the transcript, page 141 from yesterday. If you look at lines 13 to 17, page 141.
MR. HARRINGTON:
A. Yes.
GREENE, Q.C.:
Q. So you just confirm what you've just said, you believe you're more in the middle of the range. Then, I guess, Mr. Bennett also commented on Nalcor's perspective on where it feels its DG 2 estimate is within that range, and if we look further down on page 142, lines 12 to 17, Mr. Bennett stated with respect to the range that it wasn't appropriate for Nalcor to state where it thought it was within the range at this point in time. So my question to you to further understand the type of information we had at DG 2, and when we look at some of the sensitivities as to the relevance of the sensitivities, I wondered, Mr. Bennett, in light of - my understanding is that Nalcor is for this range at -50, which is the extreme range, that for DG 2 estimate, that you are not willing - that you're not

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prepared to say where you are, your view, within that range?

MR. BENNETT:

A. Well, I think that when you look at the process that's followed, of course, we will never know the accuracy of the estimate until you have a final cost to compare it against. I mean, that's the nature of the process that we're in, and as Mr. Harrington and Mr. Kean pointed out, there is an evolution and progression of the design of the project and, therefore, there is a continued evolution and increasing accuracy of estimates using the practices that they both set out in their presentation yesterday. So when we look at that, you know, we identify some trends. First of all, as Mr. Harrington pointed out, we've done extensive investigation on site, we went through a - completed a risk identification process, and we have focused attention on the key risks that we see in the project planning and project execution. So from there, it's fine to say, yes, we think that we have that done, but for Nalcor to say the estimate is within this specific range,

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it's a very difficult thing to do based on the nature of the process that we're in. So people have pointed out that the extreme edge of the range is -30 to +50 percent. There is a narrow end of the spectrum, as Mr. Harrington just pointed out as well, but other than completing the analysis that we've done, other than reviewing the nature of the work that's been completed, it would be very difficult to say that we think that the estimate is, you know, at this point in time within these specific parameters. That was the point I was trying to make yesterday.

GREENE, Q.C.:

Q. Right, and we're only talking about a DG2 Class estimate as well.

MR. BENNETT:

A. That's correct.

GREENE, Q.C.:

Q. I wonder, Mr. McNiven, if you could bring up, please, PUB Nalcor 43. The Board had asked this question as well during the RFI process, and this was - sometimes when we ask questions, you are asking 2 and 2, and you expect the answer to be 4, but in this

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particular case when you read the question, it was, "What was the degree or range of accuracy used by Nalcor for the Decision Gate 2 estimate for Muskrat Falls power". The answer didn't come back with the range. It's one of those times sometimes 2 and 2 is not 4, it's 2 and 2 is green. So I wondered if you could help me understand the answer to that question as to how that deals with the range of accuracy around the DG 2 estimate?

MR. KEAN:

A. Jason Kean. I would like to direct you to PUB Nalcor 42.

GREENE, Q.C.:

Q. I'd like to deal with 43 first, please, because the question was very specific question, and then we can go, of course, to 42, but let's deal with 43.

MR. KEAN:

A. PUB Nalcor 43 doesn't explicitly respond to the question as noted. It does provide clarity as to what is the contingency that was included in the DG 2 analysis.

GREENE, Q.C.:

Q. And the contingency, you mentioned to me

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before that one of the elements in a project cost estimate is the estimate of the cost, the capital cost estimate. Another component is the contingency, is that correct?

MR. KEAN:

A. Yes, that is correct.

GREENE, Q.C.:

Q. So the answer to the question then on Nalcor 43 with respect to a contingency, did that really relate to the accuracy range?

MR. KEAN:

A. Yes, contingency does relate to accuracy.

GREENE, Q.C.:

Q. Oh, I'm sure it does, but can you explain - and that's why perhaps you can help me understand the answer and how it related to what the range was?

MR. KEAN:

A. Yes, if I could direct you to PUB Nalcor 42.

GREENE, Q.C.:

Q. Sure.

MR. KEAN:

A. This particular RFI, the response deals with particularly on the accuracy, as stated in the - for DG 2, and if I could quote, "According

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to AACE International Recommended Practice, #18R-97, typically accuracy ranges for a Class 4 estimate can be -15 to -30 on the low side, to +20 to +50 percent on the high side, depending on the technical complexity of the project, the degree of project definition, appropriate reference information, and inclusion of appropriate contingency determination".

GREENE, Q.C.:

Q. Thank you. So that is one of the components that goes into the estimate and then you apply the range when you get to the total project cost?

MR. KEAN:

A. That's correct.

GREENE, Q.C.:

Q. The next decision point is Decision Gate 3. The degree of accuracy that would be associated with a project cost estimate for DG 3 is the AACE Class 3 estimate, is that correct?

MR. KEAN:

A. Yes, that is correct.

GREENE, Q.C.:

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Q. And the range of accuracy for that level is?

MR. KEAN:

A. The range of accuracy for a Class 3, it varies depending on the industry, but as per AACEI Recommended Practices, it's usually in the range of -20 to -10 on the low side, +10 to +30 on the high side. I will also add that in the aspects of hydro power construction, which of course is the project that we're speaking of today, there is a working group that is sitting to develop appropriate recommended practice for that industry, and I'm actually sitting on that working group. So that will provide in future greater clarity.

GREENE, Q.C.:

Q. Around the range of accuracy for hydro?

MR. KEAN:

A. Yes.

GREENE, Q.C.:

Q. So as we move forward to DG 3, we would expect to see a better - because you have more project definition for the project, the expectation is that you have more confidence in the cost estimate that will be used at that decision point, is that correct?

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MR. KEAN:

A. Yes, most certainly we will have greater confidence.

GREENE, Q.C.:

Q. We heard a little bit yesterday about the work that has been ongoing since November 2010 until the current date. I'd like now to talk about the commitments that have been made to give us an appreciation of how much work has been done. I wonder, Mr. McNiven, if you could bring up PUB Nalcor 178.

MR. MCNIVEN:

Q. PUB Nalcor 178?

GREENE, Q.C.:

Q. PUB Nalcor 178.

MR. MCNIVEN:

Q. I don't have that -

GREENE, Q.C.:

Q. With respect to that, it was a response to an RFI that was filed, I believe on Friday, so we can go through it as well. The question was how much money had been spent by Nalcor from DG 2, which was November 2010, up until the end of December 31st, until just six weeks ago? So how much money was spent.

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MR. HARRINGTON:

A. In the response to PUB Nalcor 178, the answer was the total expenditures incurred for the period from DG 2, November 2010, to December 31st, 2011, was approximately 82.8 million dollars.

GREENE, Q.C.:

Q. Okay, and then the forecast expenditures until DG 3?

MR. HARRINGTON:

Q. The forecast expenditures from January 1st, 2012, up to DG 3, are estimated at approximately 12 to 15 million dollars per month.

(11:15 a.m.)

GREENE, Q.C.:

Q. And I believe yesterday you indicated that you expected to be in a position to make a Decision Gate 3 decision in June of 2012, is that correct?

MR. HARRINGTON:

A. That's correct.

GREENE, Q.C.:

Q. So that would be approximately using the 15 million - another 90 million dollars you

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expect to spend?
MR. HARRINGTON:
A. Within the region of 12 to 15 million dollars per month at the high end, yes.
GREENE, Q.C.:
Q. And that would give some indication of the amount of engineering, financial, other type work that has been done to further refine the project definition, to further define the project cost estimate, is that correct?
MR. HARRINGTON:
A. That is correct.
GREENE, Q.C.:
Q. Part of the work that has been ongoing is to prepare tenders as well that will be required for the work, is that correct?
MR. HARRINGTON:
A. That is correct.
GREENE, Q.C.:
Q. I wonder, Mr. McNiven, if you could go to the website for Nalcor for Lower Churchill, where the tenders are posted. I wonder if you could just describe some of the tenders that are outstanding, whether this list is up to date, and to give us an indication of the total

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value of the tenders that are ready to be awarded?
MR. HARRINGTON:
A. I can talk to the actual package titles, but I really don't have the value of those at my fingertips.
GREENE, Q.C.:
Q. I wonder if Nalcor could provide some indication of the total value of the tenders that are either now ready - that are listed as pending, or ready to be awarded.
O'REILLY, Q.C.:
Q. I'm sorry, would you repeat that?
GREENE, Q.C.:
Q. I wonder if Nalcor could provide an indication of the value of the tenders that are listed as being ready to be awarded or that are pending, the ones they have listed on the website?
O'REILLY, Q.C.:
Q. A listing of those?
GREENE, Q.C.:
Q. Just the value - no, the listing is there; the value, how much money are we talking about that Nalcor is ready to award or almost ready to award.

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MR. HARRINGTON:
A. It's very - I mean, we're in a bidding process, so for me to provide the Board or anybody with information that would provide to the bidder -
GREENE, Q.C.:
Q. And I don't mean by individual tender. I just meant a sum - rule of thumb, you know, how much money, the value of the work that's ready to be awarded from a global perspective, not by each individual.
MR. HARRINGTON:
A. Oh, okay. We can do that. Would you like me to step through the package titles now?
GREENE, Q.C.:
Q. I don't know if you need to do the titles, but you can give some indication of the type of work you're ready to go to tender with.
MR. KEAN:
A. This is Jason Kean. I can step through each of the RFPs, Request for Proposals, from the top, if you wish, and provide clarity as to the scope and boundaries of those.
GREENE, Q.C.:
Q. Or some of them can be broken down by subject,

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like, getting the site ready. I was thinking more of a high level - we don't need to go through each line item.
MR. KEAN:
A. So these - okay. Starting Package CH0048, there was an expression of interest issued, and subsequently a request for proposal for the actual clearing of vegetation associated with the access road and the laydown areas at the Muskrat Falls site. That then facilitates the construction of the access road, which is noted as Package CH004, which is approximately a 19 kilometre access road from the Trans Labrador Highway to the generation site at Muskrat Falls. Further, if you could just scroll up again, there are noted some packages for equipment associated with construction power, specifically Package PH0036, 37, 38, that are packages that are required to facilitate the distribution of construction power around the Muskrat Falls construction site. That is some of the key early infrastructure works that must be established. You will also note on the top there is a Package CT0341, which is an Expression of

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Interest related to the right-of-way clearing of the transmission line between Muskrat Falls and Churchill Falls. There is also Packages CH0023 and 24, which are Expression of Interest related to seek firms that may wish to participate in the clearing of the Muskrat Falls reservoir. Package CH003 and CH002 relate to the facilities, the infrastructure facilities that must be established at Muskrat Falls, specifically the 1500 person accommodations complex and the associated administrative buildings.

GREENE, Q.C.:

Q. So in looking at this, you get the impression that Nalcor is putting itself in a position to start the project immediately with DG 3 approval. Is that correct?

MR. BENNETT:

A. We're preparing for potential project sanction and I think there is a -- there are two stages to our Decision Gate process. First is a series of analyses that need to be done in order to confirm a sanction decision, at which point funds will be made available for construction start. The other aspect of our

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planning process is to make sure that we're ready to take that work on and in order to demonstrate and be actually prepared, we need to get expressions of interest, request for proposals compiled so that we understand the costs and we're prepared to move.

Issuing the RFP is not a commitment to ultimately award the RFP, an important point to make. I think the other important point here is that some of these packages are of significant value and it's important for us to have those as inputs into our DG3 estimates. So activities like reservoir clearing, the construction camp, those are large ticket items in the capital cost estimate and would need to be -- it would be very helpful if they were available to us in greater detail than we would have from initial estimate.

GREENE, Q.C.:

Q. Do you plan on awarding any of these contracts or these tenders prior to DG3?

MR. BENNETT:

A. A decision has not been made to award those packages.

GREENE, Q.C.:

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Q. Yesterday we talked a bit about the activities that must be done before you're in a position to move to DG3 and I think your slide 43 listed some of the principal activities. Some of these activities are within Nalcor's control and some are with external parties. Mr. Harrington mentioned yesterday or said yesterday that you would be in a position to make a Decision Gate 3 in June. Did that include all of the activities with external parties or was it related only to Nalcor's activities?

MR. HARRINGTON:

A. Paul Harrington. I was referring to the activities that were within my control.

GREENE, Q.C.:

Q. So that would be doing the project definition, updating your cost estimate, those kinds of things? Is that correct?

MR. HARRINGTON:

A. Those kinds of things, that is correct.

GREENE, Q.C.:

Q. There are other activities that are listed here on the slide. The first one, which is the engineering to increase project definition

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and obtain a class three estimate, that's what you and I just talked about, isn't it, Mr. Harrington?

MR. HARRINGTON:

A. Paul Harrington. Yes, that is correct.

GREENE, Q.C.:

Q. Okay. Similarly, the next one, the procurement and contracting of long lead times, that's again within Nalcor's control? Is that correct?

MR. HARRINGTON:

A. That's correct, and the previous question kind of alluded to some of that activity.

GREENE, Q.C.:

Q. The next bullet, aboriginal consultations and agreements, that would be one I would classify in the category of there is an external party that has some input into the timing for that. Can you provide an anticipated date when that will be concluded to your satisfaction to allow you to move to DG3?

MR. HARRINGTON:

A. The aboriginal consultation of course, you know, we have the New Dawn Agreement with the Innu Nation which was a significant step along

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that path towards DG3 and in fact towards DG2. We are also carrying out consultations with aboriginal groups in accordance with the requirements of the environmental assessment processes which are under way. So aboriginal consultation is an ongoing event. We also consult with aboriginal groups regarding permitting as well. So it's an ongoing thing. It's not necessarily on or off. It's just making sure that, yes, that's something that we check that we're on target.

GREENE, Q.C.:

Q. So that's not a trigger that must be pulled before you get to DG3?

MR. HARRINGTON:

A. Yes, it's a degree of readiness. Can I characterize it in that way? It's not necessarily on or off. It's a matter of how far along you are and you know, it's up to others to make that decision, yes, we are far enough along.

GREENE, Q.C.:

Q. Now the environmental release is the next bullet where -- is that a situation where there actually has to -- there will be a

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definite point at which you know you have environmental release and you can proceed? Is that different than the aboriginal consultations?

MR. BENNETT:

A. It's Gilbert Bennett. Yes, we will receive ultimately a response to the Joint Panel Review Report in the form of a decision by the Federal and Provincial governments.

GREENE, Q.C.:

Q. And that dealt with the generation facilities?

MR. BENNETT:

A. Yes, that's right.

GREENE, Q.C.:

Q. Do you have an update as to the anticipated date for that decision?

MR. BENNETT:

A. Those are both Cabinet decisions and we wouldn't have a committed date from either government.

GREENE, Q.C.:

Q. What about the environmental assessment process for the transmission line?

MR. BENNETT:

A. The Environmental Impact Statement

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Comprehensive Study for the transmission, the Labrador-Island transmission link will be filed imminently with the two governments. It is a comprehensive study. It's not a panel process. That will go into that process within, I expect, the next month and a half.

GREENE, Q.C.:

Q. So again, that would be more definitive than the aboriginal consultations? There will be clearance or no clearance that will allow you to go to DG3?

MR. BENNETT:

A. That's right.

GREENE, Q.C.:

Q. We've already had limited discussion on the Federal loan guarantee. Is that something that must be in place before DG3 decision can be made?

MR. BENNETT:

A. I think that decision would depend on the progress and outcome of negotiations at the time. You know, we're working with Canada. The province is working with Canada. I can't make a determination as to whether that's a prerequisite.

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GREENE, Q.C.:

Q. So that's a maybe, okay. What about the agreement with Emera and the Maritime link?

MR. BENNETT:

A. The analysis that we've used for DG2 is not -- does not indicate that Emera and the conclusion of those agreements is a prerequisite to selecting Muskrat Falls or the Labrador-Island link as a preferred alternative.

GREENE, Q.C.:

Q. Other activities that would be done before DG3, we've talked about some of them as well. One is a new load forecast. Is that correct, an update of the load forecast and the generation expansion plan?

MR. HUMPHRIES:

A. Yes, that's correct.

GREENE, Q.C.:

Q. When do you anticipate that that will be completed?

MR. HUMPHRIES:

A. That will be done in anticipation of DG3, which is midyear, June.

GREENE, Q.C.:

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Q. The CPW analysis, will that be updated for Decision Gate 3?
MR. HUMPHRIES:
A. It's Paul Humphries. Yes, it will.
GREENE, Q.C.:
Q. And again, the timing for that?
MR. HUMPHRIES:
A. It will be at the same time of the strategist analysis. It will all be done as a complete package.
GREENE, Q.C.:
Q. And it all comes together in midyear, is it?
MR. HUMPHRIES:
A. Yeah.
GREENE, Q.C.:
Q. When the engineering work is done as well?
(11:30 a.m.)
MR. HUMPHRIES:
A. Well, there's going to be -- there will be a slight delay between the finalization of costs and the completion of that review and analysis, updated analysis, but it will all be in that general time frame, yes.
GREENE, Q.C.:
Q. And there had been a previous risk assessment,

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a project risk assessment completed for DG2. Will there be an updated risk assessment provided for the project as of DG3?
MR. KEAN:
A. Jason Kean. Yes, the risk assessment process is an ongoing process. A thorough and comprehensive risk analysis will be completed pre DG3 to define the appropriate accuracy, as well as a contingency recommendation.
GREENE, Q.C.:
Q. And that updated risk assessment will identify the key risks as determined following your detailed engineering? Is that correct? And the mitigation strategies that deal with the risks?
MR. KEAN:
A. Jason Kean. Risk management is an ongoing activity within the project. The purpose of the risk analysis is to translate -- is now once you have completed a base cost and schedule expectation, you consider the risks that are around those and the analysis facilitates a more informed decision about contingencies ranges.
GREENE, Q.C.:

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Q. So the risk assessment you'll have done to support the DG3 decision will identify all of the major risks that you will have identified at that point in time? Is that correct?
MR. KEAN:
A. Yes, that is the intention.
GREENE, Q.C.:
Q. And it will include what the mitigation strategies are to deal with the identified risks?
MR. KEAN:
A. Jason Kean. Yes, that is the intention.
GREENE, Q.C.:
Q. Another item that had been mentioned in the documentation filed by Nalcor that was a critical factor is the successful completion of your pilot on the horizontal drilling. Do you view that as a show stopper for DG3, in other words, you must have a successful completion of a pilot for the HDD drilling?
MR. HARRINGTON:
A. This is Paul Harrington. Currently, the horizontal directional drilled hole is at 1.5 kilometres. So you know, we're pretty close right now to doing the initial hole. The

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second part of that geotechnical information that we're gathering and putting together will include a reaming out of that existing hole. So you know, it's not an on-off type situation. We are pretty confident that we -- you know, that the technology is robust. We just wanted to gather all of the geotechnical information together on that pilot hole to make sure that we weren't missing anything.
GREENE, Q.C.:
Q. So will the successful completion of the pilot, will you require that that be completed before you make a DG3 decision?
MR. HARRINGTON:
A. No.
GREENE, Q.C.:
Q. Okay. So that's not one, what I call a show stopper?
MR. HARRINGTON:
A. No.
GREENE, Q.C.:
Q. Okay. Are there other items that must be completed before you'll be able to move through DG3, other than the ones we've just talked about?

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MR. HARRINGTON:
A. I think there was another slide which identified -- again, you know, some of them are within my purview and some aren't, so it's difficult for me to answer that question absolutely because I can't.
GREENE, Q.C.:
Q. If you look at the slide that's up there now that we talked about first, slide 43, those are the ones that Nalcor had outlined as being required prior to DG3. We just talked about some additional ones that weren't shown on slide 43 and my question is: in addition to what's on slide 43 and in addition to the ones we just talked about, is there anything, from your perspective, that needs to be completed before you're in a position to make the decision at DG3?
MR. HARRINGTON:
A. Paul Harrington. Looking at this list, which is fairly broad, I would say that from a project perspective, we've covered off all of the items there.
GREENE, Q.C.:
Q. And the anticipation right now is that all of

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these activities will be at a point where you hope to be able to make a decision approximately midyear about proceeding to project sanction?
MR. HARRINGTON:
A. That is correct.
GREENE, Q.C.:
Q. For all of the factors we just talked about? They're all going to come together so that in midyear you will be in a position to review and make a recommendation on whether you have successfully met DG3?
MR. HARRINGTON:
A. Paul Harrington. Yes, that is what the project team is striving to achieve.
GREENE, Q.C.:
Q. Okay. So the anticipated date, not only for the project engineering work to be complete and the project estimate and the schedule to be updated, it is actually June for all of those activities? Is that what I take from your response?
MR. HARRINGTON:
A. Paul Harrington here. The engineering complete, I think is what you said?

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GREENE, Q.C.:
Q. I meant in terms of a DG3 for your project definition to allow you to go to tender. I meant complete but for what you require for DG3.
MR. HARRINGTON:
A. Well, of course, if it's complete.
GREENE, Q.C.:
Q. And all the other activities -- my only point is that all of these activities are going to come together in midyear so that you can make a decision.
MR. BENNETT:
A. It's Gilbert Bennett. To the extent that some of those factors are beyond our control, we couldn't commit that they would be done ultimately by midyear.
GREENE, Q.C.:
Q. And that -
MR. BENNETT:
A. But we have an expectation that, you know, if those processes process normally, yes, they would be complete by midyear.
GREENE, Q.C.:
Q. Okay. So that's all I was -- what is the

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anticipated date for all of these activities. It is the same, okay. And at that point in time, at DG3, we see that we do have a fuller definition of the project and a more -- from your perspective, you will have greater confidence in the cost estimates that we have before the -- than we have the estimate that's now before the Board?
MR. HARRINGTON:
A. I couldn't quite hear what you said at the end there, sorry.
GREENE, Q.C.:
Q. Okay. Right now, as we've already talked about, the estimate that the Board has before it is as of August 2010?
MR. HARRINGTON:
A. That is correct.
GREENE, Q.C.:
Q. You hope to make a decision in midyear on proceeding to project sanction where you will have an updated number of items that are critical to you, one of which will be a new cost estimate for the project which will be based on a better definition as you've evolved the definition of what's required for the

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project?
MR. HARRINGTON:
A. Yes, that is correct.
GREENE, Q.C.:
Q. So approximately midyear in 2012, there will be all of this updated information available which will provide a greater -- which will be different than what's now before the Board in terms of the cost estimate, the degree of accuracy for that estimate, the project definition, et cetera?
MR. HARRINGTON:
A. Yes.
GREENE, Q.C.:
Q. I wanted now to turn to the topic of load, so perhaps Mr. Stratton might like to join the panel for this.
Yesterday, Mr. Stratton, you stated that the last forecast or the forecast that was used for the analysis that is before the Board was 2010 load forecast? Is that correct?
MR. STRATTON:
A. Paul Stratton. Yes, that is correct.
GREENE, Q.C.:
Q. Okay. When does Nalcor normally prepare a

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load forecast?
MR. STRATTON:
A. Paul Stratton. Our forecasting process is generally an annual forecast process that is undertaken in the fall of the year and is finalized sometime in the spring of the year. What's involved with that is an economic forecast from the Department of Finance that flows into that, an energy price forecast that is provided to us from the PIRA Energy Group, and our own internal estimates of wholesale pricing of electricity.
GREENE, Q.C.:
Q. So this is an annual exercise that you look at every year normally?
MR. STRATTON:
A. That is correct.
GREENE, Q.C.:
Q. Why wasn't it done for 2011?
MR. STRATTON:
A. Because of all the -- we decided to keep a consistent set of forecasts and information to flow into this, the DG2 analysis and to complete this process with the Public Utilities Board.

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GREENE, Q.C.:
Q. In terms of the forecast that was presented to the Board for the analysis for the in-feed versus Isolated island scenario, did you extend the normal time frame that you look at in doing the load forecast?
MR. STRATTON:
A. Yes, that is correct. Our traditional forecast would be for a period of 20 years.
GREENE, Q.C.:
Q. And how did you take it then from the 20-year period you normally do for the entire period for the sensitivity analysis, which is what, 57 years or so after 2067?
MR. STRATTON:
A. Yes, the methodology that we applied in this instance was we looked at the total provincial require -- or sorry, the total island requirements of load in the latter period of the forecast and we took an average of the last five year period and projected that out an average load increment and extended that out with allowances for electric heat saturation in the province because one of the major drivers of load in the province is

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electric heat. Once our electric heat is saturated, then our load will be more a function of our economic growth in the province and the end, or I guess we tailored that down in the load forecast to what we expect would be an economic growth load for the island.
GREENE, Q.C.:
Q. One of the questions that has arisen is the length of the forecast period, and what is your level of confidence in taking out what you normally do for a 20-year forecast, out for an additional 37 years? Does that affect the confidence level you have in your load forecast?
MR. STRATTON:
A. I guess as a load forecaster, I would expect that as time goes out in the load forecast, there is the possibility that there would be more error in that forecast. But the methodology that we have used, as a forecaster, I believe that to be a reasonable forecast over that time.
GREENE, Q.C.:
Q. Okay. Looking at the industrial component of

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the load forecast and just to get an appreciation for the size of that in comparison to the load, would you agree that the total -- the industrial load as a percentage of the total Island load can vary from 17 to 20-21 percent depending on the year we're looking at in your forecast period?

MR. STRATTON:

A. I think I need to see a point of reference here.

GREENE, Q.C.:

Q. If you want to look at Exhibit 1, Addendum 3. Normally what is the percentage of the industrial load of the total island load? That was the only question I was asking, and I'm saying it varies year by year, but roughly is in the range 17-18 percent up to 20-21 percent over the forecast period.

MR. STRATTON:

A. I'm not sure I understand your question, sorry.

GREENE, Q.C.:

Q. Of the total load for the island, so much is domestic. We usually broke it down into big categories as domestic or residential load;

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there's the industrial load.

MR. STRATTON:

A. Correct.

GREENE, Q.C.:

Q. Two of them together, the residential load which in that I include general service, all of your small businesses, that plus the large industrial customers make up the total island load.

MR. STRATTON:

A. Correct.

GREENE, Q.C.:

Q. Okay. What's the breakdown between those two big components of the load? The residential load is what percent versus the industrial load?

(11:45 a.m.)

MR. STRATTON:

A. I'm not sure I have those numbers in front of me. I can get them.

GREENE, Q.C.:

Q. Sure. It's only at a high level. We have a total island load composed of two big components. What's the percentage of one and roughly, if you look at it, let's accept for

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this assumption that my support team have done the calculations properly for me, because they've also -- and I don't expect you to do the calculation there, but -

MR. STRATTON:

A. Well, in our -

GREENE, Q.C.:

Q. - roughly 17 to 20 percent is the industrial load?

MR. STRATTON:

A. Yes, that is correct.

GREENE, Q.C.:

Q. Okay. And it's just to give people a context of what we're talking about. There's no trick questions. It's just to give people a context. The next is of the industrial load, what percentage is the Corner Brook load? So if we're talking roughly 20 percent as industrial load, who's your largest customer and what percentage of the industrial load is Corner Brook Pulp and Paper Mill? There see, I've given you a hint in the question of Corner Brook.

MR. STRATTON:

A. Corner Brook will represent the largest load

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in the industrial customer class.

GREENE, Q.C.:

Q. Okay. And subject to checking, will you agree that it's roughly -- it's over half of the industrial load comes from the Corner Brook Pulp and Paper mill, subject to checking?

MR. STRATTON:

A. Corner Brook is roughly 800 and -- sorry, roughly 960 gigawatt hour load and our total industrial load requirement I believe is approximately around 1200 gigawatt hours.

GREENE, Q.C.:

Q. I'm sorry, I didn't hear the last part, your total?

MR. STRATTON:

A. Total industrial requirements would be approximately 1200 gigawatt hours.

GREENE, Q.C.:

Q. And Corner Brook load is?

MR. STRATTON:

A. Now that's currently.

GREENE, Q.C.:

Q. Yes.

MR. STRATTON:

A. That's not in the forecast.

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GREENE, Q.C.:
Q. Right. So if you look out over the period again at the forecast, subject to checking, you'll agree that Kruger is at least half of the load generally of the industrial load?
MR. STRATTON:
A. Roughly speaking, yes.
GREENE, Q.C.:
Q. Okay. And yesterday we had a little bit of discussion about how you determine the industrial load forecast.
MR. STRATTON:
A. That's correct.
GREENE, Q.C.:
Q. Okay. And I understand from your answer that you do that by having discussions directly with the customer because they know their business best and you -
MR. STRATTON:
A. That is correct.
GREENE, Q.C.:
Q. And in fact, you mentioned, I believe, you have two -- twice during the year, you do receive updated forecasts from your industrial customers. Is that correct?

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MR. STRATTON:
A. Typically we would go out for two -- twice a year for updates to their forecast, yes, that's correct.
GREENE, Q.C.:
Q. And you also advised that you had recent discussions with Corner Brook and that there was no significant or material change in their load forecast?
MR. STRATTON:
A. That is accurate.
GREENE, Q.C.:
Q. Is that correct?
MR. STRATTON:
A. That is correct.
GREENE, Q.C.:
Q. We have seen in the past the impact that the closures of the mills can have on the total load requirements for the island. We have seen that in some of the documentation that Nalcor has supplied how the load has dropped when the two mills owned by Abitibi closed. Did you follow the same process when you were doing the load forecast when you were supplying Abitibi, that you had discussions

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with them twice a year?
MR. STRATTON:
A. We would -- in the past, we have always been consistent in our approach with dealing with the industrial customers and their requirements and back when Abitibi's, Abitibi Stephenville and Abitibi Grand Falls, were still operating, those forecasts would have been maintained in our forecast until the definitive notices were given to the province that they ceased to exist.
GREENE, Q.C.:
Q. Okay. So when you did have the updates of the industrial customer load annually, the closure of the two mills was not forecast? Is that correct, based on how you got your annual updates from them?
MR. STRATTON:
A. That is correct.
GREENE, Q.C.:
Q. You mentioned what the total requirements of the Corner Brook mill is. I believe you mentioned it was 900 and -
MR. STRATTON:
A. Approximately 965 gigawatt hours a year.

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GREENE, Q.C.:
Q. Okay. For the purpose of the analysis, Hydro chose to do a sensitivity using 880 gigawatt hours, which is somewhat less than the Corner Brook load, the total requirements of the mill, and we talked yesterday about the impact that that would have. I wonder if we could go to PUB-Nalcor-51, please? And if you could scroll down? We talked about that yesterday. If the 880 gigawatt hours or the 140 megawatt load is taken out of the forecast starting in 2013 -- so if the load is lost and we don't have -- that amount of load is lost, there was a question yesterday with respect to the impact that that would have on the capacity deficit and the energy deficit and I wonder, Mr. Humphries, in terms of that, again subject to check, for the calculations done, would you agree that the capacity deficit is probably 2020-2021?
MR. HUMPHRIES:
A. Yes, I'd agree it's in that range.
GREENE, Q.C.:
Q. Okay. And the energy deficit would be into 2030-2031?

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MR. HUMPHRIES:
A. Subject to check, yes, I agree with that.
GREENE, Q.C.:
Q. And I'm just checking my numbers as well for -- I think I gave you the right numbers that -- so if that amount of load is lost, it has a significant impact on when capacity is required and energy as well? Is that correct?
MR. HUMPHRIES:
A. Yes, it would.
GREENE, Q.C.:
Q. And I just wonder because the MHI report referred to the significance of the industrial load for the total island load requirement, given the small nature of our industrial base, three customers going to one and additional one, and with the history of the two mill closures and with the significance of this type of load on your generation expansion plan, has Hydro considered doing any independent studies with respect to the pulp and paper industry in the province and its forecast future?
MR. HUMPHRIES:
A. No, we have not.

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GREENE, Q.C.:
Q. The sensitivity or the analysis supplied to the Board assumes that the Corner Brook load is there until 2067? Is that correct?
MR. STRATTON:
A. Paul Stratton. Yes, that's correct.
GREENE, Q.C.:
Q. Okay. And we also heard yesterday, of course, that there's also an assumption that there is no new industrial load?
MR. STRATTON:
A. That is correct as well.
GREENE, Q.C.:
Q. Have you considered doing any sensitivities around the impact on the generation expansion plan of the loss of a significant industrial load and how that will be factored into your analysis?
MR. HUMPHRIES:
A. Paul Humphries. Again, the timing of that reduction is a significant factor. If that reduction in load would come post the Muskrat Falls decision, I think the analysis has shown that the Interconnected alternative is still the cost effective choice. But prior -- if the reduction were to come prior, obviously the urgency of the decision to make a capacity or energy decision has changed.

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GREENE, Q.C.:
Q. So given that, one of the considerations is -- or has Nalcor considered moving in an incremental way to put -- right now a capacity deficit in 2015 and your energy deficit is what, 2020-2021? Would you consider putting in something to address the peaking problem before you run into the energy problem by adding a combustion turbine or doing a small hydro site to gain additional certainty with respect to the future load of your industrial customer group?
MR. HUMPHRIES:
A. Well, in reality, that's what's happening. We are adding a combustion turbine for the capacity issue in for 2015. So that window, our energy deficit is 2020. So there is a time frame there.
GREENE, Q.C.:
Q. In terms of adding additional combustion turbines.
MR. HUMPHRIES:

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A. Beyond the -
GREENE, Q.C.:
Q. Yeah. The one that you've already built into your plan.
MR. HUMPHRIES:
A. No, we really haven't considered that, no.
GREENE, Q.C.:
Q. I'd like to look at the load growth in Labrador in so far as it impacts the load on the island and I wonder if you would go to PUB-Nalcor 16, please, Mr. McNiven?
MR. MCNIVEN:
A. 16?
GREENE, Q.C.:
Q. 16. There's been -- Mr. Johnson brought you to some commentary in the media in his questions yesterday. Another one as -- and we just talked about another issue that has been in the media which was the future of the Corner Brook mill. This one deals with the media coverage of potential load growth in Labrador and this one is framed in terms of a specific -- a potential specific load growth and I'd like you to comment first about the potential for the load growth for Rio Tinto

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with respect to the mine in Labrador, given there's been so much media attention to it. Is Nalcor aware of future load requirements of expansion?

MR. HUMPHRIES:

A. Yes, we are.

GREENE, Q.C.:

Q. And what is the order of magnitude of that? Because based on the media reports, it would be a very significant increase in load for you.

MR. HUMPHRIES:

A. It has the potential to be a significant increase in load, yes.

GREENE, Q.C.:

Q. The question was if that load were to materialize as you just -- as the announcements in the media, what impact it would have on your generation expansion plan? And when you say it would be a significant expansion of load, could you indicate an order of magnitude that you are -- is the potential you're talking about?

MR. HUMPHRIES:

A. It could be up to a 500 megawatt load,

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additional load.

GREENE, Q.C.:

Q. Are there other potential load growth that you expect in Labrador--or that is anticipated in the same way as Rio Tinto?

MR. HUMPHRIES:

A. Well there are numerous, I guess, opportunities in Labrador, as there have been for the past twenty years we've been talking about load increases in Labrador, and we continually interface with these potential customers, but we have no firm commitment from either of those yet, including IOC, so it's difficult to incorporate that into the planning process in any real kind of way that you would commit dollars to, to address until we have a firm commitment.

GREENE, Q.C.:

Q. In the past there has been also a discussion about an aluminum smelter which was--didn't occur, I'd say that was speculative, are you saying that the potential for the expansion in Labrador that we're talking about here is as speculative as the aluminum smelter would have been?

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MR. HUMPHRIES:

Q. It's less speculative than the aluminum smelter--it would be less speculative than the aluminum smelter, but it's still not what we would consider a firm request.

GREENE, Q.C.:

Q. And how does Nalcor then plan for future potential load growth? Do you need a signed power contract? How do you build that into your planning?

MR. HUMPHRIES:

A. Well generally on the Island--in the Island scenario, yes, we would have to have a firm commitment from a customer because in most cases it would involve a requirement to build and add additional resource, so--and there would be a lead time, be it three to five years, whatever would be required to establish that generation.

GREENE, Q.C.:

Q. So if we were fortunate enough for a large customer to come, you'd say, sorry, we--come back in three or five years?

MR. HUMPHRIES:

A. No, that's not necessarily the case, there are

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things that you could do in the interim, particularly in Labrador. On the Island, an isolated scenario is you don't have many options; there's not much you can do. But in Labrador, we do have existing recall energy, there's the opportunity to import energy for a customer in the interim, and if we do build Muskrat Falls, there will be excess capacity in Muskrat Falls available to supply a new customer in short notice.

(12:00 p.m.)

GREENE, Q.C.:

Q. That's a good lead into where I wanted to go next. If we scroll down to--the question was: If the load materialized, how would you meet the load? So if you can please keep going down, the answer was--it's the next page actually--the answer was that in the event any of the projects proceed, you would have two terawatt hours of production available from Muskrat 'cause this is what you don't require and you don't have it committed to Emera, so rather than selling out west, you'll use it in Labrador and also your recall power. And then we have Cull Island at the larger site would

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also be available to meet those needs. So they would have to be, Gull Island would have to be developed, of course, which would--if these loads materialize?

HUMPHRIES:

A. Well again it depends on the ultimate size, if it's an extremely large load, Gull Island may make sense, but there are also alternatives available on the Island that we could develop, the remaining hydros and wind, now the fact that we would have an interconnection, that would help to address a, what I would call a medium size problem.

GREENE, Q.C.:

Q. So there would be future developments to address it. Can we go, please, to PUB-NALCOR-72? I will give you a moment to read that, Mr. Humphries. This talks about if the load materializes in Labrador, just as announced by IOC or Rio Tinto, how that would use the energy from Muskrat Falls and if you read through, I'll give you a moment, but the question will be is that by 2027 all of Muskrat Falls would be required to supply the load and then we would start to see a deficit

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on the Island.

MR. HUMPHRIES:

A. Could you page down a bit please?

GREENE, Q.C.:

Q. So the idea being that yes, if this load materializes and if you're going to use Muskrat to supply it, we're going to run out of Muskrat energy to meet the Island load requirements in the--around 2027, so you would have to develop something else for the Island?

MR. HUMPHRIES:

A. We would have to develop another source, whether it was for the Island or alternately -

GREENE, Q.C.:

Q. Right, so this could have a significant impact then on the generation expansion plan, should the--for the Island, should the Industrial load actually develop in Labrador?

MR. HUMPHRIES:

A. It would have an effect on the expansion plan overall, yes.

GREENE, Q.C.:

Q. And it would be a significant impact, depending on the size of the load?

MR. HUMPHRIES:

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A. Depending on the size of the load, we could have a significant impact on expansion plan, yes.

GREENE, Q.C.:

Q. Is Nalcor in discussions now? And I'm not going to the content of the discussions, but do you have any expectation as to when there might be greater certainty with respect to these potential loads in Labrador?

MR. HUMPHRIES:

A. No, I do not.

GREENE, Q.C.:

Q. I'd like to turn now to the issue of the probabilistic reliability assessment and MHI's recommendations that that type of reliability assessment be completed certainly before decision gate 3? I wonder if you could bring up slide 65, Mr. McNiven, from Nalcor's presentation yesterday. So here Nalcor is responding to one of MHI's recommendations and if you go to the next slide please? I took that slide and your information yesterday to be that you are agreeing with MHI's recommendation and that you will be doing the type of probabilistic reliability assessment

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for the overall in-feed option, including the generation facility and the link as recommended by MHI. Is that what I should have taken from that?

MR. HUMPHRIES:

A. Yeah, we will be doing the probabilistic models for the link and incorporating that in our probabilistic generation expansion analysis, yes. So the probabilistic--the forced outage rate which we are currently using in our analysis was based on a previous probabilistic model and then we agree it was old and dated, but we are currently in the process of updating that model to reflect the current thinking of the Muskrat Falls Maritime Link and that will be incorporated in the new analysis for DG3.

GREENE, Q.C.:

Q. You're talking about the PTI studies for the 1980s?

MR. HUMPHRIES:

A. Yes, I am.

GREENE, Q.C.:

Q. So you have accepted MHI's recommendation?

MR. HUMPHRIES:

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A. Yes.
GREENE, Q.C.:
Q. Was there any reason why you hadn't updated the 1980 studies prior to now?
MR. HUMPHRIES:
A. We're in the process, for DG2 we did not have them updated, we were in the process of updating.
GREENE, Q.C.:
Q. On the NERC Standards, I'd like to go to that recommendation. Again you addressed that yesterday and that would be slide 69, Mr. McNiven. Does Nalcor agree that compliance with NERC's Standards now has become part of the phrase "good utility practice" which is commonly used by utilities, they state they're complying with good utility practice and right now in Canada that would include compliance with NERC's Standards?
MR. HUMPHRIES:
A. Compliance with NERC's Standards in Canada is still mandatory--or still discretionary or voluntary, sorry, so again it's left up to the discretion of the jurisdiction in question, but when we look at dealing with entities in

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the United States or participating in the market, the significance of these standards becomes more important and in some cases would be considered mandatory for operating in those markets.
GREENE, Q.C.:
Q. It's my understanding that eight of the ten provinces, the utilities in eight of ten provinces now comply with NERC Standards, with the only two exceptions being PEI and Newfoundland, is that your understanding?
MR. HUMPHRIES:
A. I think that's correct.
GREENE, Q.C.:
Q. If we look at slide 69 and this was in response to the recommendation in the MHI report that Nalcor undertake a self assessment and get ready for compliance with NERC. I wasn't sure and this is one I wanted Nalcor to comment on, as to whether they agree with that recommendation or not and what action they're taking in response to it?
MR. HUMPHRIES:
A. Yes, we agree with that and we are doing a self assessment prior to DG3 to determine the

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actual level of compliance that would be required to satisfy the--NPCC, Northeast Power Co-ordinating Council requirements for full membership. Whether that would mean a blanket adoption of all the reliability standards or a portion of those, or adapting some of those to current situations, particularly on the Island system where we're exploring those opportunities and we feel, because of the nature of the connection that we have or will have with the North American grid, both to Labrador and to Nova Scotia, if that happens, because it's a HVDC link, the significance of reliability events on the Island will have less of an impact on the neighbouring jurisdictions. So some of the conditions on the Island that may not necessarily comply fully with NERC Standards at this stage, it may not be mandatory that we would need those in place, day one, or even ever and they could be grandfathered.
GREENE, Q.C.:
Q. I am going to ask you about the implications of that for your interconnection with Nova Scotia, just in July, 2011, the Nova Scotia

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Utility Board has mandated that Nova Scotia Power follow NERC Standards. Have you looked at the implications of if there is to be an interconnection with Nova Scotia, what that will mean for Newfoundland?
MR. HUMPHRIES:
A. Yes, and we have to look at what it means for Newfoundland as opposed to what means to Nova Scotia as well.
GREENE, Q.C.:
Q. Um.
MR. HUMPHRIES:
A. Yes, we enter in discussion with ourselves and Nova Scotia and the regulator to determine what those implications are.
GREENE, Q.C.:
Q. And are you able to say at this point in time in that consideration whether it will require additional work to be included with respect to any aspects of the Muskrat Falls project, which would affect the project definition and/or the project costs?
MR. HUMPHRIES:
A. I'm not in a position to say definitely, no, I am not.

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GREENE, Q.C.:
Q. Do you anticipate that it will?
MR. HUMPHRIES:
A. We don't anticipate that it will be significant.
GREENE, Q.C.:
Q. Some--you mentioned that the current reliability criteria, you would be assessing those as well with the compliance with respect to NERC? Can you just give a little, perhaps overview from your perspective the differences between Nalcor's or Hydro's planning criteria and system operational requirements and what would be required if you do--if you are required to meet NERC's Standards?
MR. HUMPHRIES:
A. From the perspective of the basic philosophies of our criterias, again, they are very similar. The major differences are how we respond to contingency situations and in certain scenarios, the level of redundancy when they have internal stations and those types of things, like backup power supplies and redundant systems. Those are the bigger differences, but from the perspective of how

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they will affect our requirements to the NERC complaint, the biggest factor is do these deficiencies, could they have an impact on the reliability of our neighbouring systems. And as I said earlier, because of the DC link connections, the likelihood of any of these events causing issues is low and if we go through a process and demonstrate this to the regulatory councils, there's no reason to expect that these deficiencies cannot be grandfathered in because they're of no problem to anyone, other than ourselves.
GREENE, Q.C.:
Q. Just to follow up on that, my understanding of what you just said is if we can shut off Newfoundland so that it does not impact the supply, going to Nova Scotia is not an issue because as long as you can firewall Nova Scotia, Newfoundland won't have to be compliant with NERC Standards?
MR. HUMPHRIES:
A. No, that's not what I said, I said like for, let's take an example of our Hardwoods Terminal Station or our Oxen Pond Terminal Station here in the city, they are the largest

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source of supply for the city. If we were to lose one of those stations, it has an impact to us internally, but it's not likely that it was affect anything beyond our boarders. So the requirement to make NERC compliance applicable to Hardwoods or Oxen Pond Terminal Station would be our own decision which we would make based on an economic decision at the time. It wouldn't be required to be complaint to interface with the rest of the network.
(12:45 p.m.)
GREENE, Q.C.:
Q. And can you explain, just so people understand, if something were to happen at Oxen Pond or Hardwoods, in your example, for the terminal station there was less power available to Newfoundland, are you saying that you wouldn't reduce your exports to Nova Scotia, it would be Newfoundland you would take it from?
MR. HUMPHRIES:
A. There's nothing that would happen at Hardwoods and Oxen Pond that would make less power available, it would make less power available

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to a pocket of customers in the St. John's area, but it would not affect our interfaces with either Quebec through Labrador, or Nova Scotia via the Maritime Link.
GREENE, Q.C.:
Q. I just wanted to make sure that was understood. The other--in your planning criteria one of the differences with NERC is on the generation, whether you have backup generation. The Newfoundland standard is, the two, the loss of load hour expectation, how does that compare to a NERC Standard?
MR. HUMPHRIES:
A. Well again, our LOLH, loss of load hours, I guess that's what you're speaking of, for the Island is--right now it's 2.8 hours and that, to take it back in, it means, it represents an issue of an outage of one in five years, a probability of one in five years of not being able to serve their load.
GREENE, Q.C.:
Q. So that means the Newfoundland system is built to that standard -
MR. HUMPHRIES:
A. It's built to that--that's the standard in

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which we progress to before we would initiate additional additions of capacity or grant capacity 'because it's a capacity factor. In the North American Standard, it's double that, one in ten years. By virtue of the fact that we will have an interconnection to the North American grid and we're part of that network and could enter into reserve sharing agreements with our neighbours, to comply with a one in ten year is not a large issue, it happens naturally. The reserves are there and it would not bring any additional -

GREENE, Q.C.:

Q. So you would address it by dealing with interconnection agreements with -

MR. HUMPHRIES:

A. Reserve sharing agreements with our neighbours and things like that.

GREENE, Q.C.:

Q. But through the interconnection.

MR. HUMPHRIES:

A. Yes, through the interconnection.

GREENE, Q.C.:

Q. I want now to turn to the fuel price forecast. I guess we've seen that one of the critical

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factors is fuel price and that the fuel costs make up about 70 percent of the cost for the Isolated Island Option. So in order to swing the preference, it's pretty hard without some impact on the fuel. So on of the key assumptions you used in doing the CPW analysis is the forecast price of fuel for the forecast period. And we talked a little bit about that yesterday. So how long was the period that you forecasted fuel prices for, Mr. Goudie?

MR. GOUDIE:

A. Steve Goudie. The PIRA based forecast goes from 2010 to 2025 and then we extend that out, we hold the 2025 price constant in real terms, and then we just extend that out by the general inflation rate of two percent.

GREENE, Q.C.:

Q. So you forecast the price of oil out to 2067, which is the length of the forecast period?

MR. GOUDIE:

A. We do.

GREENE, Q.C.:

Q. And just to give people an appreciation for the prices that you're talking about throughout that period, perhaps if we could go

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to Nalcor's submission, page 38?

MR. MCNIVEN:

GREENE, Q.C.:

Q. Is that the book Volume 1?

GREENE, Q.C.:

Q. Yes, sorry, Volume 1. So if you could bring it up a little bit higher on the screen to see. So can you just take us through some of the key--the time periods here and what you have used in the base case at relevant periods, because this is the forecast you used, as I understand it, in the analysis for the price of fuel in your analysis.

MR. GOUDIE:

A. The columns labelled Reference Forecast at January 2010 are the prices that entered into the CPW analysis.

GREENE, Q.C.:

Q. And if you scroll to the bottom, so in 2025, the forecast would have been 145 dollars and can you explain the difference between when you used .7 percent fuel and 2.2 percent fuel, why you are showing both columns on the page?

MR. GOUDIE:

A. Under the Isolated Island Strategist run, we

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used 0.7 percent low sulphur fuel until the scrubbers are in service and then we -

GREENE, Q.C.:

Q. Which is when? 2020?

MR. GOUDIE:

A. 2015, around 2015, and then we revert to a higher sulphur fuel of 2.2 percent and then we utilize that fuel out to the end of the service life in the Holyrood units.

GREENE, Q.C.:

Q. So in this particular reference you stopped at 2025, can you give some indication what the numbers were past that? Say, 2040, what would you have used for number 2.2 fuel then?

MR. GOUDIE:

A. All forecasts beyond the 2025 planning horizon here would have been escalated at a two percent inflation rate.

GREENE, Q.C.:

Q. So if I did that, what would I have for 2.2 percent fuel in 2067?

MR. GOUDIE:

A. In 2067? I don't have that now right here in front of me, but I think our point would be that they are constant in real terms. We are

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not escalating above the rate of inflation.
GREENE, Q.C.:
Q. And so when you looked at the fuel price, we saw already that it is one of the biggest movers in the CPW analysis, can we look at RFI MHI-Nalcor 41, Rev1 for sensitivity please? Page 2. And one of the ones that Mr. Johnson talked about yesterday in looking at the sensitivities, was where there was a decrease of fuel cost by 44 percent and I just wanted you to explain what is that 44 percent from? Is it from those fuel prices we just talked about?
MR. GOUDIE:
A. It's 44 percent across the board decrease in the reference prices that were in the Strategist run.
GREENE, Q.C.:
Q. Right, so the forecast that we just looked at, all of the prices would be 44 percent lower?
MR. GOUDIE:
A. Yes, that's correct.
GREENE, Q.C.:
Q. In terms of looking at that, I think you already indicated that fuel is about 70

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percent of the cost in the Isolated Island of the 8.8 billion?
MR. GOUDIE:
A. It is 70 percent of the CPW, yes, that's correct.
GREENE, Q.C.:
Q. And as these sensitivities illustrate that changes in the fuel price have a significant impact on the preference?
MR. GOUDIE:
A. It does.
GREENE, Q.C.:
Q. One of the, again the public issues that there's been comment about is the difficulty in forecasting fuel prices. We don't know next week, because if we did, I guess we may-- if we had that ability to actually determine fuel price, we'd probably all be somewhere else, but because there's so much uncertainty around it, we don't know what it would be, as evidenced by fuel by fuel price variability in the last few years. How does Nalcor take that into account, the difficulty in forecasting fuel prices over the 57 year analysis period? What weight do you place on that risk?

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MR. GOUDIE:
A. Well we handle it by going in with a reputable company that produces a comprehensive analysis behind their fuel price projections. We do sensitivity analysis to understand the leverage that alternative price projections to our reference case would have on our base case results. I mean, the uncertainty is prevailing and one of the reasons why we analyze and ultimately recommend an Interconnectioned Island Option is exactly to get rid of that uncertainty because if that uncertainty ever comes home to roost on the wrong side, electricity will be very un-affordable on the Island of Newfoundland.
GREENE, Q.C.:
Q. So that's the uncertainty--the probability that it will probably go higher, rather than lower in your base case.
MR. GOUDIE:
A. Well I mean, based on PIRA's, you know, professional assessment, they have the high and low and pretty well even odds, but they are based on specific analysis that they do.
GREENE, Q.C.:

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Q. And we've heard that PIRA is a provider of fuel price forecast, have you considered or reviewed getting forecasts from other known fuel price forecasters?
MR. GOUDIE:
A. Not -
GREENE, Q.C.:
Q. How did you select PIRA for example, and have you considered others?
MR. GOUDIE:
A. Well we selected PIRA back in the late 1990s because we were all in need of a reputable company that could assist Hydro in putting forward projections for its bunker fuel cost at Holyrood from a company that would be basically accepted by the PUB and by the Intervenors. When we considered them initially, we looked at their client list and their reputation and I mean, today PIRA has an excess of 500 clients around the world, all of the major oil and gas companies subscribe to PIRA services, all of energy marketers, petroleum refineries, all major world commercial banks, so they are well respected in the energy market analysis field.

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GREENE, Q.C.:
Q. Have you considered using any other provider of that forecast--in recent years?
MR. GOUDIE:
A. In this review, we have not explicitly considered anybody else, but we have been mindful of where other projections are that are publicly available, such as EIA or NEB.
GREENE, Q.C.:
Q. And as we heard yesterday, Nalcor's evidence is that those costs, their projections are consistent when you look at the fact that they are--how you have done the forecast, one is in constant dollars and one is not?
MR. GOUDIE:
A. Yes, that's correct, yes. Our projections are all in nominal dollars.
GREENE, Q.C.:
Q. Thank you, Mr. Chair, that is a convenient place to break, in terms of the flow if it's convenient -
CHAIRMAN:
Q. Okay, we'll break for lunch. I just got one quick request arising from this navigant issue here and I'd just like you to run the numbers,

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assuming the carbon pricing comes in effect in 2017, what would that mean in terms of a carbon charge per domestic rate payer in Newfoundland? Because I mean I see you got 2.65 million, it's driven up, it rises to 2.65 million because of the incidents of carbon pricing. And what would interest me is from a domestic rate payer, what would that mean if this should come to pass?
MR. GOUDIE:
A. Okay, we'll take that one.
CHAIRMAN:
Q. Thank you.
GREENE, Q.C.:
Q. We'll reconvene at 2:00 Mr. Chair?
CHAIRMAN:
Q. Yes, sorry, 2:00 we'll start again.
(12:30 p.m.)
(Adjourned for Lunch)
(2:03 p.m.)
CHAIRMAN:
Q. So I think we're--are there any preliminary matters? So I think we're back to ....
GREENE, Q.C.:
Q. Thank you, Mr. Chair. I understand this

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morning there may have been some difficulty in hearing me.
O'REILLY, Q.C.:
Q. Much better.
GREENE, Q.C.:
Q. Okay, good. I was going to say if at the back of the room, if you can just wave your hand and I'll know that you want me to speak up louder or over on the panel as well if you can't hear me, please let me know. I do have a few follow-up questions to the topics that we had talked about before lunch. And first, I'd like to talk about the Probabilistic Reliability Assessment, and Mr. Humphries, you indicated that you would be following up, Nalcor would, and would be completing a Probabilistic Reliability Assessment and spoke specifically with respect to key finding No. 5. I'd like, please, Mr. McNiven, if you could bring up the MHI report, volume 1, page 9. And there was some uncertainly among my colleagues as to whether your answer included that key finding which is No. 6 and if the Probabilistic Reliability Assessment Study to be undertaken is in the process, as I

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understand it right now, by Nalcor, will address the full extent of those studies that are described in key finding No. 6.
MR. HUMPHRIES:
A. Okay, with respect to the studies identified in Section 6, the ongoing work, no, it does not address those level of studies. Nalcor is aware, I guess, that these types of studies have been done and are done in other jurisdictions, but to date they have not been adopted as part of our normal decision-making process in the least cost analysis process.
GREENE, Q.C.:
Q. So before lunch when you said that Nalcor was updating the PTI report and was completing a Probabilistic Reliability Assessment, you were talking about only the type of work PTI had done in the 80s, which goes back to key finding No. 5, the forced outage rate update?
MR. HUMPHRIES:
A. That's correct.
GREENE, Q.C.:
Q. Well I guess I should ask you a few more questions then.
MR. HUMPHRIES:

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A. Sure.
GREENE, Q.C.:
Q. Because I had taken your answer to be that you were addressing both of those key findings and were accepting both of the recommendations. Are you familiar with the Probabilistic Reliability Assessments as discussed in the MHI report and as recommended by MHI?
MR. HUMPHRIES:
A. Yes, I am familiar.
GREENE, Q.C.:
Q. Are you aware that other major utilities use those type of assessments for major projects?
MR. HUMPHRIES:
A. Yes, I am.
GREENE, Q.C.:
Q. Would Hydro normally follow the practices of other major utilities with respect to larger Hydro projects?
MR. HUMPHRIES:
A. With respect--can we go back to your previous question first please? Could you just repeat that question again?
GREENE, Q.C.:
Q. Was Hydro aware that other major Canadian

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utilities do perform these type of Probabilistic Reliability Assessment Studies and in fact, if you look at key finding No. 6, it's stated there that Manitoba Hydro, BC Hydro, Hydro Quebec and Hydro One in Ontario have completed--would complete these types of Probabilistic Reliability Assessment Studies for major projects, such as the Muskrat Falls infeed option?
MR. HUMPHRIES:
A. Item 6 says for major projects such as--yes, I am aware that they do that, yes.
GREENE, Q.C.:
Q. Would normally Nalcor consider that practices of those types of major utilities, offer major projects, would be a practice you would normally review and consider adopting?
MR. HUMPHRIES:
A. We would normally review and consider adopting those, yes.
GREENE, Q.C.:
Q. Have you looked at MHI's recommendation and made a decision not to accept it then?
MR. HUMPHRIES:
A. No, we have not--yes, I have looked at it and

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now, we have not made a decision, not to accept it, but from the perspective of starting to incorporate this kind of analysis into our traditional base cost decision making process, is a significant deviation from our norm. And it's our view that before we would commit to doing such a, taking on such a task, that we would really need to assess, not only with ourselves, but also with stakeholders, customers and the Board, the implications of including such an analysis and what impact it may have on the overall lease cost decisions.
GREENE, Q.C.:
Q. Did you do any analysis before your DG2 decision with respect to whether you would adopt or not adopt Probabilistic Reliability Assessment Studies as done by other major Canadian utilities for large projects?
MR. HUMPHRIES:
A. Not directly related to this project, no, we did not. We have been reviewing and keeping abreast of developments in the industry, I guess, but we have not, as an organization, adopted those yet.
GREENE, Q.C.:

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Q. Do you plan to consider it now in light of MHI's recommendation?
MR. HUMPHRIES:
A. We will consider it, but as I discussed, it's not as simple as Nalcor making a decision to incorporate this level of evaluation in our decision-making process because it could have significant implications and we feel it needs to be addressed with the stakeholders, the regulator and customers.
GREENE, Q.C.:
Q. And do you plan to address it with the stakeholders prior to DG3?
MR. HUMPHRIES:
A. I do not think the time is fair to do that prior to DG3.
GREENE, Q.C.:
Q. So just to, again, for the sake of completeness, you are not accepting that recommendation or finding by MHI, nor do you plan to do any assessment of the recommendation prior to DG3?
MR. HUMPHRIES:
A. I doubt that we will be doing that assessment prior to DG3, yes, that's correct.

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GREENE, Q.C.:
Q. I'd like now to turn to Mr. Kean or Mr. Harrington with respect to the difference between DG2 and DG3 again, just a couple of follow-up questions. With respect to decision gate 2, or DG2, we talked this morning about the project definition and that at DG2, one would typically see a project definition of five to ten percent, is that correct?
MR. KEAN:
A. Jason Kean. Yes, that's what we indicated this morning.
GREENE, Q.C.:
Q. And in looking at DG 2 at that point in time you were looking at what is before the Board are two options: the indeed option and the Isolated Island option. How would you characterize both of those options in terms of project definition? Let's talk about Muskrat Falls, that was at DG2, in your view, was that project definition in the range of five to ten percent at DG2?
MR. KEAN:
A. Jason Kean. Yes, it was.
GREENE, Q.C.:

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Q. Let's look at the Isolated Island option, the documentation before the Board is that the level of analysis with respect to the components of the Isolated-Island option may not have been advanced in terms of analysis and review as was the documentation for the infeed option, would you agree with that statement?
MR. HUMPHRIES:
A. Could you repeat that question please?
GREENE, Q.C.:
Q. In the Isolate-Island option where there were components, including the pollution control upgrades at Holyrood, the eventual replacement of Holyrood, the small hydros, the wind, and the other components of the Isolated-Island option, in responses to RFI's Nalcor advised that that analysis had not been brought to the same level as the analysis on the infeed option.
MR. HUMPHRIES:
A. That's correct, yes.
GREENE, Q.C.:
Q. And that if you did so, it was most likely that the cost of the Isolated-Island option

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would increase, as opposed to decrease?
MR. HUMPHRIES:
A. That's correct.
GREENE, Q.C.:
Q. So the question is in terms of the Isolate-Island option, how would you characterize the project definition for the Isolated-Island option at DG2? We just heard that Muskrat Falls was in the range of five to ten percent, what is your view for the Isolated-Island option at DG2?
MR. HUMPHRIES:
A. At DG 2 it would be less than five percent.
GREENE, Q.C.:
Q. Now, we just talked about project definition at the DG2 stage and we know your next key decision point is called DG3, what do you expect the project definition to be normally at a DG3? I think we talked a little bit about this yesterday or you did with Mr. Johnson, so what's the normal range for project definition at DG3?
MR. KEAN:
A. Yes, it's Jason Kean. The normal--our target is to be on the upper side of the definition

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for a completion of a gateway phase 3 work, such as to provide an estimate with the greatest accuracy as possible.
GREENE, Q.C.:
Q. And that would be, what is the normal project definition range at DG3? It's five to ten percent at DG2; at DG3 it's?
MR. HUMPHRIES:
A. It would be somewhere in the range of 20 to 40 percent.
GREENE, Q.C.:
Q. Okay. Mr. Bennett, this morning you gave us an update as to where you are with the environmental assessment process. I had a follow-up question on that, is it possible that in giving approval from an environmental perspective to proceed with Muskrat Falls, that there could be conditions attached to the project going forward arising from that green light for the generation facility?
MR. BENNETT:
A. Yes, it's possible that the Federal and/or Provincial Governments may attach condition to the release of environmental assessment, assuming that such release were granted.

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GREENE, Q.C.:
Q. Has there been any costs associated with compliance with conditions included in the CPW analysis at DG2 for that?
MR. BENNETT:
A. There were a number of costs associated with environmental issues and mitigation included in that capital cost estimate, yes.
GREENE, Q.C.:
Q. But were those issues that had already been identified by Nalcor as required or was there like a contingency in the event that there was new or additional conditions imposed?
MR. BENNETT:
A. We had identified issues that we thought were going to be included as conditions in the release at DG2.
GREENE, Q.C.:
Q. Do you have a level of confidence that there are sufficient funds in the CPW to cover any conditions that may be attached to the approval by the government?
MR. BENNETT:
A. We look at the proceeding that was carried out for the generation environmental assessment

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looking back on the, you know, our proposed mitigation strategies at the time. Those are generally in conformance with what we saw in the capital cost estimate. The final disposition of recommendations made by the panel is something that is yet to be considered.
GREENE, Q.C.:
Q. Okay, similarly for the transmission line?
MR. BENNETT:
A. I think that's a fair statement there as well.
GREENE, Q.C.:
Q. I'd like now to move to a different topic which is the design for the transmission line and there has been some discussion already with you with respect to the appropriate design for the HVDC transmission line, and we've talked a bit about the standard used or the appropriate return period to be used and I'd like to refer to the MHR report, volume 1, page 61. One of MHI's findings is that the return period chosen or used by Hydro of one in fifty years doesn't meet the appropriate standard that's recognized for transmission line designs, and yesterday--I won't take you

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to the transcript unless you'd like me to, Mr. Humphries, but you talked a bit about--the question was in your view is Nalcor complying with the standard? And your answer essentially was well it depends on your interpretation of the standard, is that correct?
(2:15 p.m)
MR. HUMPHRIES:
A. Yes, that's correct.
GREENE, Q.C.:
Q. So I wanted to go through the standard with you to get your interpretation and then we'll see how it may differ from MHI's as to whether there is in fact compliance with the standard. So if we look at the MHI report, it was just the simplest way on the record to find references to the standard and if there's other sections that--I believe they have quoted the whole standard in their report, so that's why I say it's the easiest place to find it, but--so that's why I've chosen to use that as the reference point. So they do begin and do you agree that the appropriate standard as you have in Exhibit 106 is the design

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criteria of overhead transmission lines, the CEI/IEC standard that's referenced there on page 61 of the MHI report?
MR. HUMPHRIES:
A. Yes.
GREENE, Q.C.:
Q. And that is the standard you referred to in the document you filed in Exhibit 106 using your--setting out your design criteria for the line?
MR. HUMPHRIES:
A. Yes, it is.
GREENE, Q.C.:
Q. If you go to the top of the next page, page 62, I'm reading from the top of the page there. "In all cases lines should at least meet the requirements of a reliability level characterized by a return period of loads fifty years, level one." So the one in fifty year return period is considered to be the minimum, is that the way I would read that first paragraph, Mr. Humphries?
MR. HUMPHRIES:
A. That's our interpretation, yes.
GREENE, Q.C.:

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Q. Jumping down to the next paragraph, it is suggested--this is a direct quote from the Standard, "It is suggested to use a reliability level characterized by return periods of 150 years for lines above 230 kV." What is the rating for the HVDC line?

MR. HUMPHRIES:

A. It is 320 kV.

GREENE, Q.C.:

Q. The next sentence states, "So if we took that sentence as stated, it would be that one in 150 years would apply because the HVDC line is 320 kV."

MR. HUMPHRIES:

A. It suggests it should be.

GREENE, Q.C.:

Q. So it is--the word suggestion is used, right.

MR. HUMPHRIES:

A. Yes, that's correct.

MR. BENNETT:

A. Just for clarification, if I may, just for clarification on that point, I think the word "suggested" is important, it puts context around the decision, it's not a mandatory requirement and there are other sections of

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the code where there are mandatory requirements.

GREENE, Q.C.:

Q. And that is what you meant by interpretation was because the word "suggestion" is used here.

MR. HUMPHRIES:

A. Yes.

GREENE, Q.C.:

Q. So the next line goes on to say that for lines below 230--so they're saying if it's above 230, we think you should use one in a hundred and fifty, that's how, as a layperson, not having any engineering background and not designing transmission lines, I would read that, or as you better look at it and say normally if it's above 230 you do one and one fifty. So then they go on to say even if the voltage is lower on the line, so if it's lower than 230, if that line is a principle or only source of power to a load, you should also consider designing it to a higher standard, is that how I should take the second sentence, Paul?

MR. HUMPHRIES:

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A. Yes, that's correct.

GREENE, Q.C.:

Q. And then the next paragraph, because we've had some discussion around the one in 500 years and I'm going to go through with you what the implications are for the Newfoundland system of these different return periods, but I first wanted to make sure we were on the same page as to what the Standard was saying and what it meant. So then we get to the next paragraph, "Boys--or girls, I should say people, in certain circumstances you should even go to a higher return period which is a reliability level characterized by return periods of 500 years for lines above 230 where the line is the principle of the only--or perhaps the only source of supply to a particular load, and there failure would have serious consequences of power supply." So that's again from the Standard perspective is there should be a higher reliability depending on the criticality of the line.

MR. HUMPHRIES:

A. That's correct.

GREENE, Q.C.:

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Q. And I believe you mentioned yesterday that after the ice storm in Quebec, Hydro Quebec changed and enhanced their design to 1 in 500 years, is that correct?

MR. HUMPHRIES:

A. As far as I'm aware, yes, that's correct.

GREENE, Q.C.:

Q. And those lines that they enhanced were not all just for only source of supply, were they?

MR. HUMPHRIES:

A. I suspect not, but I'm not sure.

GREENE, Q.C.:

Q. Would you like to check or undertake to check, or do you feel comfortable enough in going with the assumption that not all the lines they upgraded were sole source bringing in generation from a sole source?

MR. HUMPHRIES:

A. I'm comfortable with that for now, yes.

GREENE, Q.C.:

Q. So they decided to go to the higher return period as a result of the consequence of the impact of the ice storm on the residents of Quebec, even though it was a higher cost.

MR. HUMPHRIES:

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A. Yes.
GREENE, Q.C.:
Q. From an engineering perspective, maybe not considering the societal costs of the failure.
MR. HUMPHRIES:
A. It was a higher cost, but it also they had a much larger customer base to spread that cost over as well, compared to Newfoundland.
GREENE, Q.C.:
Q. So, you're concerned about the cost of the rate payer of--and we're going to come to that in the combustion turbines and the costs and -
MR. HUMPHRIES:
A. Yes.
GREENE, Q.C.:
Q. So, we will get to the impact on the rate payers because that will be one concern. You wouldn't do it because it's just too expensive and we're only a small island, two little rate payers. So, we can be in the dark more than they can in Quebec because they can afford to pay for it.
MR. HUMPHRIES:
A. No, you're reading words into my thoughts there I think.

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GREENE, Q.C.:
Q. Anyway, so we'll come to it in terms of the return period. Actually, I really should get you to clarify, you raised the statement before lunch where we could have an outage at Hardwoods or at Oxen Pond so that the power would be out here in the Avalon but the power would still be going to the Maritimes?
MR. HUMPHRIES:
A. Yes, the power could be going to everyone expect the immediate customers served by that station.
GREENE, Q.C.:
Q. And that is just the fact that the power system is not a conscious choice if they would be given preferential treatment or--just wanted to make sure -
MR. HUMPHRIES:
A. My no means, no.
GREENE, Q.C.
Q. One of the reasons you've given--before I get to that, I guess, my understanding from looking at the documentation is that the design period for the line, in fact, had been at more than 150 years and that that--it was

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changed to 150 years just before decision gate 2. Can you confirm that for me, please?
MR. HUMPHRIES:
A. It was changed prior to decision gate 2, I think. If we go back to the scenario prior to the Muskrat Falls, when we were looking at the 1600 megawatt bi-pole multi-terminal tie to New Brunswick and Soldiers Pond, we were considering a 1 in 150 year design, in that case. Because in that case it would have been an only supply to the Island. It was a much larger line and we did consider a 1 in 150 in that scenario. It was carrying 1600 megawatts of capacity, a portion to Newfoundland and a portion to New Brunswick.
GREENE, Q.C.:
Q. Sorry, I'm not sure. I thought you had agreed that it had been at 1 in 150 and that decision -
MR. HUMPHRIES:
A. It was -
GREENE, Q.C.:
Q. It was, okay.
MR. HUMPHRIES:
A. - in that stage. When we converted to the

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current scheme and was Muskrat Falls and the 320 kV bi-pole to Soldiers Pond with the potential add-on for the Maritime link, that is when we changed the design to 1 in 50. That was not just prior to DG2. That was early in the evolution of this concept.
GREENE, Q.C.:
Q. Perhaps over the break, I'll show your counsel the exhibit that I am referring to and the date that's referenced in it. I can't bring it up on the screen because it's a confidential exhibit.
O'REILLY, Q.C.:
Q. I'm sorry, the question is?
GREENE, Q.C.:
Q. The timing when they changed the design return period from 1 in 150 to 1 in 150.
O'REILLY, Q.C.:
Q. The date?
GREENE, Q.C.:
Q. Yes. We can come back to that after the break.
MR. HUMPHRIES:
A. Sure.
GREENE, Q.C.:

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Q. Just to make sure we're talking about the same and that I understand I your answer to me. I just wanted to have that discussion.

You mention the size of the line coming in, the HVDC line that's coming in is going to be sized for 900 megawatts, 2 poles, 450 a pole.

MR. HUMPHRIES:

A. 450 a pole, yes, with an overload capability on each pole.

GREENE, Q.C.:

Q. Or you could do--you can take the total load on one pole for ten minutes and then 150 percent of the load on that same--if you lose a pole, you can carry the full load for ten minutes on one pole and then 150 percent continuous after that, correct?

MR. HUMPHRIES:

A. That's correct, yes.

GREENE, Q.C.:

Q. So, that's a large load coming in from Labrador to the Island. Do we have any--what's the next largest load on the Island? This is a 900 megawatt line you're going to be bringing in.

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MR. HUMPHRIES:

A. Just back up here for a second. It's a large capacity, yes, it is a large capacity, but from the perspective of the load on the Island, is that all that capacity needed on the Island in 2017, 2021, 2022? No, it's not. Effectively we are using that line to replace the Holyrood plant which has a capacity of 500 megawatts. So, from the perspective of what's coming out of the system and what's coming in, we're not talking about 900 megawatts. We're talking about 500 megawatts.

GREENE, Q.C.:

Q. When Holyrood closes and the load forecast that you filed before the Board shows you using all of Muskrat Falls energy over your forecast period, doesn't it?

MR. HUMPHRIES:

A. Yes, it does, over the forecast period. It also shows that we add additional generation for capacity addition on the Island during that forecast period in excess of 250 megawatts.

GREENE, Q.C.:

Q. Yes, but at the points during the forecast period you will be looking to the line to bring in the full amount of Muskrat Falls energy to the Island?

MR. HUMPHRIES:

A. I think about the time we would be at this stage where we would be using the full capacity for the Island, there would be additional backup added on the Island. We may be bringing it in, but the fact there would be sufficient reserve on the Island to compensate for a significant portion of that capacity.

GREENE, Q.C.:

Q. Okay. So, you've gone to the next point that you're going to have backup, but I guess it's during periods of the forecast period, the full amount will be coming over the line and you will have reserve backed up--you will be adding generation on the Island. So, yes, you may have additional backup and you'll be adding, et cetera, but at some stages, you will be bringing the full amount of capacity energy over that line to the Island.

MR. HUMPHRIES:

A. At some stage, we will, yes.

GREENE, Q.C.:

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Q. Throughout the forecast period--and we're going to come actually and look at the energy balances. We'll talk a little bit more about when you're going to start using all of the energy from Muskrat. Because that's one of the concerns, that you don't start using the energy until later in the period, and we're going to come to that.

So, at some stage and we can go back, if you like and look at the energy tables for how long and when you'll be bringing in, but you'll be bringing in the full amount over the infeed. So, 900 megawatts is pretty darn big load, isn't it?

MR. HUMPHRIES:

A. It's significant, yes.

GREENE, Q.C.:

Q. So, when you come back to the CSA standard which is that there is a suggestion that it is 1 in 150 for lines above 230. You say that's only a suggestion, it's not mandatory. So, that's why you believe you're complying with CSA even though they suggested it should be a higher standard. How would you deal with the qualification, the concern they raised where

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it is--in that case it's not a principle, but it's--I call it where it's a critical line that's bringing in a large source of generation. Does that play into it at all for you

MR. HUMPHRIES:

A. Well, from the perspective of critical, I think, we need to go back and look at, in relation to what the total peak load is on the Island and the actual energy requirements. And to use some round numbers, let's assume the peak is 2000 megawatts and we have an energy requirement of, let's say for round numbers, let's say 10 gigawatt hours. It could be a little bit less than that, but for round numbers. So, when we look at, from the capacity perspective, 2000 megawatts, the 900 megawatts at the time when we do reach it's maximum requirement, it's coming close to 50 percent, yes. But when we look at the periods, we also have to--when we do that, look at the other generating additions that are being made on the Island from, as load grows and on average it's around, it's more like 20 to 25 percent of the capacity of that

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line that would be critical in the event of a loss. Because we would be carrying reserve which, for the most part, would be on the Island. So, whether that's significant, it's definitely not the full capacity and we feel it's not half the capacity.

So, our view is that it is a manageable number. From the energy perspective, if we fully utilize Muskrat Falls which is 5 terawatt hours, again, we're looking at a load of 10, in the end, it is 50 percent, but it takes a long time to get to that 50 percent. And as we're getting there, we are adding additional generating capacity on the Island system that would compensate for the loss of that line.

GREENE, Q.C.:

Q. Even though it is a 900 megawatts, you said, out of 2000, it is, in your views, that isn't significant enough to cause you, by itself, to consider, leaving apart the idea it's only a suggestion that you go to 1 in 150, if it's above 230, You're saying that even that the face that it's almost 50 percent of your load, is not enough to -

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(2:30 p.m.)

MR. HUMPHRIES:

A. And we also--the duration of the outage has to be factored into this as well. That is the significant part, particularly from the energy perspective. And, you know, statements that this line could be out for considerable periods of time, we don't believe, from the perspective, that the normal, if we had a failure, the normal restoration time would be in the two week timeframe. We don't anticipate a situation where this line is going to be down for half the year.

GREENE, Q.C.:

Q. Let's go there to the two-week window for repair time which I had planned to--you led me there earlier than I had planned, but I will just circle back.

The two-week window that you've used in Exhibit 106 as the maximum repair time, where did that come from? Is it a metric accepted in the utility industry?

MR. HUMPHRIES:

A. No, it's based on our historic information, an average of what it's taken us to restore 230

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kV transmission on the Island as a result of a number of ice storms we've had in the past 30 years.

GREENE, Q.C.:

Q. So, you're basing it on your experience with the current 230 kV system.

MR. HUMPHRIES:

A. Yes.

GREENE, Q.C.:

Q. I think yesterday Mr. Harrington referred to the Long Range Mountains as one of the areas of risk for the HVDC infeed in talking about what the identified risks are. And we can go to the transcript, if we like, but that was one of the areas. It has been commonly accepted that coming over the Long Range Mountains in Newfoundland is one of the riskiest areas. Do you have any current lines in those condition?

MR. HUMPHRIES:

A. No, we don't.

GREENE, Q.C.:

Q. So, when you're talking about the two-week window, I'd like to explore with you the operational plan that Nalcor has in place to

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address outages in the Long Range Mountains. And I think MHI has raised this in terms of the type of plan they had expected to see, having developed a plan for available inventory of steel structures or anything that would available in the event of an outage.

MR. HUMPHRIES:

A. Does somebody in the Project want to address that?

MR. KEAN:

A. Yes, it's Jason Kean. One of the activities that the Project team has been engaged in throughout the design of the line is looking at the types of structures and, of course, the number of structures that would be required in consideration of the type of line outage we could have. Further design of the structures includes considerable number of dead ends to avoid cascading events. So, that is part of the work that we are doing presently.

GREENE, Q.C.:

Q. That is, in terms of what the actual structure is and I think you mentioned yesterday that you had advanced in terms of what information had been provided to the Board for the DG2

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analysis that you had looked at design loadings in some of the structures. My question was, have you developed an operational plan with respect to available inventories and whether they would be required to be stored anywhere along so that they could be ready access which is one of the operational risks that are involved with an outage in these types of environment. I appreciate your answer which was dealing with your looking at the design of the line which is one risk. And by the way, you mentioned yesterday you were gone to tender for structural steel. The only thing that was on your website was for the AC line, would that be the same for the DC line?

MR. KEAN:

A. The RFP that's been issued is for the AC line only.

GREENE, Q.C.:

Q. So, in terms of how you would deal with the operation--I'm just trying to explore and get you to explain how you chose the two week window from your experience in the current 230 system would be applicable for the HVDC system

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and how you've made that determination in light of the different nature of the terrain and the climactic conditionals along the terrain? So, Mr. Humphries, you were saying, based on your experience with the 230 system, have you done any analysis to show whether the same conditions would apply? And if so, I'd like you to talk about the Alpine regions and the analysis that you've done to show that it is the same sort of experience you'd expect to see in what you've described as the Alpine regions which includes part of the Long Range Mountains?

MR. HUMPHRIES:

A. I am not familiar with the level of analysis that has been done, but to get back to Mr. Kean's point, I guess, on some of the things that are being incorporated in the design to limit the -- in the event that we have an outage, to limit the impact by limiting the number of spans because of anti-cascading structures. Coming from that, we will be able to have a more realistic handle on the level -- the amounts of materials we would need to have on hand to react to an event, should it

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happen and also, based on our history, I guess, the events we have had have been more significant because we haven't had that level of reenforcement. We haven't had the anti-cascading structures. We've been in situations where we've had larger numbers and spans unavailable and we have been successful in restoring transmission in these time frames.

With respect to the Long Range Mountains and those areas, no, we don't have any experience because we haven't been operating in those areas, but I think it's safe to say that if there's any extra reenforcement incorporated in the design, it will be in that area and we will be looking at things to further mitigate the probability of a complete failure, possibly even to the extent of separating the conductors on separate structures in the high risk areas, so that if there were a failure, the probability of losing both poles would be reduced again.

GREENE, Q.C.:

Q. One of the findings in the MHI report was with respect to the lack of information that was

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available on the HVDC transmission line, including the design loadings, the root, et cetera. I know you've mentioned there's been a significant amount of work done since. Is any of that information available now?

MR. HUMPHRIES:

A. I don't have it. I don't know if anyone in the project would want to comment on that.

MR. BENNETT:

A. It's Gilbert Bennett. That work is not yet complete.

GREENE, Q.C.:

Q. Okay. So, and just I know you explained yesterday and so that people are following us, you've talked about how you would beef up. You would add the anti-cascading. You would put in more towers. Just to explain again, that does not affect the return period? That's something you would do. It doesn't relate to having more of that just because you're going to the higher return period? Maybe you could just refresh people's memory about that.

MR. BENNETT:

A. It's Gilbert Bennett. Maybe I'll put some

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context around that. The whole evaluation of the return period and the discussion that we've had to date about the establishment of the return period, I think maybe has not considered some of the significant work that has been done, both by Hydro and Nalcor, over the past number of years in respect of the Avalon Peninsula, and I think in Exhibit 106, I think Mr. Thomas made a note that if you refer explicitly to the numbers and ice loading information that's provided by CSA in the standard, that the numbers that we're seeing on the Avalon Peninsula system in particular go well beyond what are expected in the standard. So when we look at the methodology that was described in Exhibit 97, there's a comprehensive approach to establishing those return periods and certainly from Hydro's historical perspective, there have been a number of activities undertaken over the years to improve the performance of the AC system, particularly on the Avalon Peninsula and so there's a learning process that has been undertaken over a number of years. Those learnings have been built in

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to the current design. So, for example, on the Avalon Peninsula, our designed ice loading is 75 millimetres of ice, which based on the history that we've seen over the operating period of this transmission facility corresponds to the maximum loading that we've seen over approximately a 50-year period.

So the anti-cascade structures, they help reduce the extent of an outage. The ice loading and the meteorological information is what takes us to the return period. So, all of those learnings, both in respect of analysis of meteorological conditions, has helped inform the design and certainly all of the operational considerations that we've learned over the years have also been incorporated into this design as well.

GREENE, Q.C.:

Q. And in looking at the upgrade of the 230 kV transmission system, which the Commissioners are familiar with, because it was upgrade program that was brought forward and approved by the Board specifically as a capital project, with the improved design criteria, I guess one of the questions is how do you take

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that data that you have for your Avalon Peninsula 230 kV and whether that's appropriate for bringing in, acknowledging that it's an HVDC line at a higher voltage and is bringing in a major source of power over very difficult terrain conditions, and that's only these types of issues that we're trying to explore with you in terms of your decision on the 1 in 50, given that our independent expert has said that's not good enough, it should be at least 1 in 150 if you have an alternative supply available. So we will explore some of those issues further.

I guess one of the -- talking about your AC system, and yes, it has been upgraded and there's been significant dollars spent to do that in the last period of time. One of the reasons you advance for not building the DC line to a higher standard is what's the point. Your AC system is at 1 in 150, so if that's going to be down, there's no point in having your DC system still standing. I'd like to talk to you a little bit about that because as a layperson, I found that kind of troubling or hard to understand why and what that meant.

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So, first, and I can take you to the RFI, if you'd like, but I gather, Mr. Humphries, that was one of the rationales put forward for it?

MR. HUMPHRIES:

A. It was and it is applicable and I think still will be applicable on the Avalon Peninsula, as an example, you know, which still the ice design on the Avalon Peninsula is not 1 in 50 even. It's 1 in 25 and if there were an icing event in excess of, let's say in excess of 1 in 50 years or at the 1 in 50 year level, there is a high likelihood that the link will still be standing and the supporting 230 kV lines coming out of the converter station at Soldier's Pond and serving the local load will have failed. So you know, that's -- yeah, we can take a level of comfort in the increased reliability of the link, but we still have a lesser of a design on our underlying bulk 230 kV transmission system which is, at the end of the day, what serves the load in the province.

GREENE, Q.C.:

Q. And I can understand that when you're talking about the same -- the storm hitting the Avalon

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Peninsula, taking out your AC and your DC.

MR. HUMPHRIES:

A. That's right.

GREENE, Q.C.:

Q. You're saying that because that happens and your AC system, the converter is not working, you can't take power, so there's no point in having your line up, and I guess sitting at home with the lights out, I was just wondering if the AC system was down, boy, and if I was at Nalcor, I wouldn't want my DC system down too. I get the AC system back and that's running, but boy, the DC system is down too, so I would rather have at least one of them up and standing if you lost the other system. That's my layman's interpretation. I don't want both lines flattened as my crews go out to repair them.

MR. BENNETT:

A. It's Gilbert Bennett. I think it's important to clarify that the design criteria that we're using for the DC system are the most robust and stringent criteria for any transmission line in the province. So, the 75 millimetre criteria that we're using on the Avalon is the

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most robust criterion for any line on the Avalon and the same is true when we look at the other loading areas. That the comparable loading for other lines in those regions is still lighter than anything we've done on the DC system.

GREENE, Q.C.:

Q. You're talking again about the ice loading which goes to how you can beef up within a return period, I guess, is what you're bringing me to. You're talking about the ice loadings when you talk about the 75 millimetres?

MR. BENNETT:

A. Well, the ice loading, of course is -

GREENE, Q.C.:

Q. That's what you're talking about, isn't it, the -

MR. BENNETT:

A. Well, that's targeted from the return period. So we look at wind, ice, the line wind and ice.

GREENE, Q.C.:

Q. Ambient temperature, all of that goes into your design loading, right, okay. So that was

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part of what I was -- when you say there's no point in having one part of your system better than the other, but the response would be, Mr. Humphries, if you were doing that, you know, both lines are down, it's no different than one line being down, whether it's your AC or your DC?

MR. BENNETT:

A. Well -

GREENE, Q.C.:

Q. If it hits the Avalon?

MR. BENNETT:

A. It's Gilbert again. I guess the other way of considering that is if you're going to make an investment in reliability improvement, the question that begs itself is where is the most opportune place to make that investment that provides the most increase in reliability for customers.

GREENE, Q.C.:

Q. Okay. So we want to go to the combustion turbines?

MR. BENNETT:

A. Well, even in transmission lines.

GREENE, Q.C.:

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Q. Okay.
MR. BENNETT:
A. I think Mr. Thomas pointed out in Exhibit 106 that an improvement -- you would get a greater improvement in overall reliability by investing in the AC system, as opposed to continued investment in the DC side.
GREENE, Q.C.:
Q. So if we can go with that, so your AC system would be up, your DC system could be down and you wouldn't have, at some points, depending on when it happened, without your backup here, you would lose all of the in-feed, which could be as much as 900 megawatts, and depending on when it happens, it depends on your available backup.
MR. BENNETT:
A. I'm not sure I follow that.
GREENE, Q.C.:
Q. You said that you would rather invest in the AC system rather than the DC system. Is that what -- that's the way I took the answer.
MR. HUMPHRIES:
A. I think that's only to the point that you would bring the lines to a comparable level of

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reliability. We wouldn't invest to bring the 230 kV lines on the Avalon Peninsula to a 1 in 150 year design when we only have 1 in 50 years on the link. We wouldn't do that.
GREENE, Q.C.:
Q. We've only talked about storms on the Avalon Peninsula which could also affect both. If you had a storm on the AC system outside of the Avalon that could impact only that one small area of the province and wouldn't impact the DC line, would it? I'm just trying to understand the thing where you said it's better to have a strong AC system and we can have the same storm affecting only a very small part of your AC system if it's at 1 in 50 and if you have 1 in 150 for your DC line, your DC line is still standing right throughout the province.
MR. HUMPHRIES:
A. Yes, it would have to depend on the -- it is specific to the location of the line. There's no question about that.
GREENE, Q.C.:
Q. And it is more of a concern if the big storm happens to hit on the Avalon for both lines?

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MR. HUMPHRIES:
A. Yeah, but again, that's where our load -- our load centre is on the Avalon Peninsula.
GREENE, Q.C.:
Q. Now we've talked about the difference between the 1 in 50 and the 1 in 150 for the return period. There's also reference in the MHI report to that criteria is where there is an alternate supply available and if there's no alternate supply, it should be 500, the return period should be 1 in 500 and I believe you gave some indication of cost this morning as to the cost for doing that which was 250 million. Is Nalcor giving any consideration -- I assume the -- well, what is the consideration you're giving now to the return period design for the line, given MHI's recommendation?
MR. HUMPHRIES:
A. I guess based on my comments yesterday, we are still remaining at the 1 in 50.
GREENE, Q.C.:
Q. Okay.
MR. HUMPHRIES:
A. And it will be a balance between line design

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and backup generation to provide a level of reliability that overall best suits the requirements of the customers.
GREENE, Q.C.:
Q. Before we get to the backup generation issue, the Alpine regions are mentioned in the MHI report as areas where there should be special consideration given, given the meterological conditions that exist. What are the four Alpine regions that have been identified in your meteorological studies? For ease of reference, they are shown in MHI, Volume 1, page 62.
MR. BENNETT:
A. It's my recollection on those Alpine areas, there's a short section in Labrador on the coast. There's the Long Range Mountains crossing, and if my memory is correct, there's a short section in the western part of Central Newfoundland, and in those areas, in those Alpine loading areas, as we pointed out in Exhibit 97, we have not finalized the loading criteria in those regions.
GREENE, Q.C.:
Q. So you haven't addressed the issue of any

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additional cost if you were to add additional reliability enhancements to address the Alpine region?

MR. BENNETT:

A. We are expecting that the ice loading in those regions and the wind loading in those regions will be higher than in the eastern and Avalon sections of the project. They will be on 75 millimetres of ice. They will be on 50 millimetres that we use in most of the line. Those are extreme areas. We recognize that and they have been -- some provision for that has been included in our DG2 work.

GREENE, Q.C.:

Q. And what about the costs of doing those enhancements? Has there been any inclusion in the CPW for the -- to reflect additional costs for the Alpine region and the transmission line?

MR. BENNETT:

A. We have been expecting heavy loading in those areas for quite some time, so for the short distances that are involved in those areas, our structural estimates would have been higher on a per kilometre basis than you would

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look at elsewhere in the system.

GREENE, Q.C.:

Q. I wonder could you -- is it possible for you to give us an indication of the costs involved in adding the additional transmission line reliability enhancements in the Alpine regions?

MR. BENNETT:

A. We don't have that here with us, I'm afraid.

GREENE, Q.C.:

Q. Can I have it as an undertaking that you'll provide it?

O'REILLY, Q.C.:

Q. We have it, we can -

GREENE, Q.C.:

Q. Okay. Now if we go to the issue of the backup generation that we were talking about. I believe yesterday you mentioned, and Mr. Humphries mentioned it earlier this afternoon, well you could have backup generation so the level of unsupplied energy could be addressed in having backup generation instead of improving the design of the line. Can I take you to PUB-Nalcor-175, please, Mr. McNiven? So if we -- this question dealt with if

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there were a bi-pole outage, how would Nalcor deal with the outage. So if we scroll down, you get a -- and you refer to certain measures that would be taken and we talk about the Strait of Belle Isle, et cetera, and the additional risk, but if you keep going until it gets to the HVDC line, and I don't know here, Mr. Humphries, beginning there on Exhibit 106, I don't know, you might want to talk about how you've did the calculation, looking at the level of unsupplied energy in the in-feed option versus the Isolated island option for the two-week repair window you talked about.

MR. HUMPHRIES:

A. Yes, and again, the analysis done in Exhibit 106 is a deterministic type analysis and it deals with identifying the worst case exposure and we felt that important that to identify that if this line failed at the worst possible time, what would the ultimate exposure to customers be and the levels of unserved energy, we went through and we looked at our load shave, our anticipated load shave and we've done calculations of the levels of

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unserved energy during this worse two-week period and it comes back to when we'd look at it from a probabilistic perspective, the probability of having the line fail in the peak week is not very significant. Normally icing doesn't happen at peak times. It's at the -- what we'd call the shoulder periods in the late fall or early spring and during those periods, the actual exposure or exposure to unserved load is lower again because the load is just not there. We're not at peak. So when we did this exercise in Exhibit 106, the intent was there to show, regardless of the probability, if this happened at the worst possible time, what would it look like and where would we be.

GREENE, Q.C.:

Q. And if your outage was for this minimum -- you said that the maximum outage would be a two-week period based on your experience with your current existing 230 system. We've already talked about whether that's a realistic metric or not, but that's how you derived -- you're taking two weeks. You get everything back and running in two weeks and this is the level of

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unsupplied energy that would be not met during that two-week outage?

MR. HUMPHRIES:

A. That's right.

GREENE, Q.C.:

Q. Okay. So if you continue to scroll down, the question was whether -- your answer was that there would be periods that there was going to be unsupplied energy and the question was what would you have to install to ensure that the level of unsupplied energy for the in-feed was going to be the same as in the isolated option? Do you recall how many combustion gas turbines was going to be required?

MR. HUMPHRIES:

A. As I recall, I think it was 11 combustion gas turbines.

GREENE, Q.C.:

Q. So for that -- and we'll come to the difference in the level of unsupplied energy between the in-feed and the Isolated, but in order to ensure that in the in-feed option for the level would be the same as the Isolated option, it would require 11 combustion gas turbines to be installed around the island to

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keep that level the same as the Isolated island option?

MR. HUMPHRIES:

A. That's correct.

GREENE, Q.C.:

Q. And what was the cost of those 11 gas turbines?

MR. HUMPHRIES:

A. I don't have the capital cost, the total capital cost but I think the cumulative present worth difference of the expansion analysis was less than 400 million dollars.

(3:00 p.m.)

GREENE, Q.C.:

Q. Yes, if you go to -- it was 350 million dollars I believe you answered the question that that would be the impact on the CPW?

MR. HUMPHRIES:

A. Yes.

GREENE, Q.C.:

Q. So to put in the 11 gas turbines to provide that same level of reliability as the isolated island option, it would be 11 gas turbines at a cost of 350 million dollars?

MR. HUMPHRIES:

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A. That's correct.

GREENE, Q.C.:

Q. And that is not in the CPW analysis at present, is it?

MR. HUMPHRIES:

A. No. That would -- actually, it would represent an advancement of cost in the CPW analysis. These gas turbines actually get added but later in the analysis, so if you -- when we look at, 11 gas turbines costs a lot more than 375 million dollars, but all we're doing, we're advancing the cost and we would bring them forward for transmission reliability backup earlier than we would for our LOLH requirement.

GREENE, Q.C.:

Q. But would -- it was the impact on the CPW, I think the indication to the answer was 350 million dollars it would add to the in-feed as a cost?

MR. HUMPHRIES:

A. That's correct.

GREENE, Q.C.:

Q. So it would decrease the preference by that amount for the isolated?

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MR. HUMPHRIES:

A. That's correct.

GREENE, Q.C.:

Q. Alright. Now just looking at the level of unsupplied energy for using your same analysis, the two-week window, your worst two-week window, you're going to get all the lines up in two weeks for the DC line coming across the Long Range Mountains, comparing that, the level of unsupplied energy in the in-feed option versus the isolated option, can we go to PUB-Nalcor-168, I believe it is?

And in looking at -- or we could have gone to your Table 5, 106, if you'd prefer.

MR. HUMPHRIES:

A. Yes.

GREENE, Q.C.:

Q. It's just the same data. To me, it's just what I was used to for getting the number. But for me, Mr. McNiven, I need it back for the numbers. It's in two pages. It's just -- when you did the table for the exhibit, you demonstrated -- the question was the level of unsupplied energy for your two-week window based on your load and the way the question

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and you confirmed in the answer is that for -- if you look at the isolated island option, the unsupplied varies from zero megawatt hours up to 19, almost 20,000 megawatt hours for the years 2017 to 2037. Is that correct, Mr. Humphries?

MR. HUMPHRIES:

A. Yes, that's correct.

GREENE, Q.C.:

Q. Okay. Now if we looked at the Interconnected option for the very same period using the very same repair outage, we see that the unsupplied energy now goes from 14 megawatt hours up to almost 94,000 megawatt hours over the same period. So to a layperson again reading that, to me there's more opportunity for unsupplied energy during the two-week outage in the in-feed option versus the isolated island option. Is that correct?

MR. HUMPHRIES:

A. Based on those numbers and during those periods, yes, that's correct.

GREENE, Q.C.:

Q. Now could I go to PUB-Nalcor-174? And this is -- I wanted to discuss with Nalcor what

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happens if the bi-pole is down, we do have the level of unsupplied energy that we just talked about and we're not able to supply load, how will Nalcor provide that load? And in looking at this, we see about how you're going to do it and if you want, Mr. Humphries, you can either just tell us how you would do it and how you would deal with under frequency load shedding, et cetera, in that situation and what it would mean for the ratepayers?

MR. HUMPHRIES:

A. Could you just page down a little further, so it's -

GREENE, Q.C.:

Q. And you don't have to refer to that. It's just it's -- because I'm sure you know it by heart as to -

MR. HUMPHRIES:

A. Yeah, okay. Well, what would happen, in the event that we were in a situation where we did not have the capacity to serve the load, again based on the -- and if this were at the worst period of time, worst loading period, the peak period, there would be a number of hours during a day where we would be short and we

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would have to revert to load rotations and those types of things. For the most part, there would not be -- based on our load data, there would not be a full 24-hour period where we would resort to that. There would probably be a period of eight to ten, maybe even 12 hours a day, where we would have no problem with serving the load, but to get over those peaks, we would either -- we would interrupt or rotate blocks of load amongst customers for those periods each day until we got the line back in service and repaired, and even within that two-week period, our peak doesn't last -- our peak only lasts a day or two. So the worst exposure and the maximum amount of load rotation would take place probably over a 48-hour period and as we went either side of that in the two-week period, there would still be load rotations, but they would be less significant.

GREENE, Q.C.:

Q. Okay. I wonder if we could go to PUB-Nalcor-31, which talks a little bit more about under frequency load shedding, what it would mean. So, if we scroll down to the bottom of the

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page, can you just -- it talks about there, if we could begin by reading at line 23, Mr. Humphries, where the sentence begins "in addition to tripping load centres," and if you want, you can just take a moment to get the context of the question and the answer. It just describes your under frequency load shedding scheme.

MR. HUMPHRIES:

A. Okay. From the perspective of the event, the transition and there's two issues going. When we look at -- from the -- in the context of the Labrador-Island link, there are two events that could happen, I guess. One is the loss of a pole and what happens there and the design at that stage is from the -- that would be transparent to the customer with the overload capabilities and the ten-minute continuous 150 percent overloads, that would be a transparent event and that is one of the integration studies which are ongoing. That is one of the contingencies that will be investigated and confirmed.

From the perspective of when we lose that bi-pole, that is not going to be -- the actual

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transition, the contingency when that happens, that will not be a seamless event, you know. There's going to be under frequency load shedding. There will be -- we will have to possibly segregate portions of the system and then we will come back and recover and put the system back together with the available generation that we have and if there's enough generation there, everything will continue on. If there's not, we will enter into these load rotations like I spoke of.

And that will be true at any stage for a loss of the bi-pole, even if -- for argument sake, even if we had the Maritime link and we had a sudden loss of that full 800 megawatt or 900 megawatt supply to the island, it's not going to be seamless. There would be special protection plans in place to isolate areas of load and we would go through an orderly restoration. It's not going to turn around on a dime. Even if the Maritime link was there, you can't turn it around on a dime and pull 500 megawatts in. There would be a restoration period involved. So when that event happens, as we call transiently from the

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time the event happens until it settles out, there will be special protections and operations going on and service will not be normal, but it will be comparable to any emergency type event that you would have for a major failure on a system.

GREENE, Q.C.:

Q. And just you were explaining that and then the line, beginning at line 25, "it is expected that the Avalon Peninsula and potentially the Burin Peninsula, depending upon system load, conditions and HVDC link load conditions will need to be tripped to maintain an electrically isolated island containing remaining hydro electric resources." So again, to a layperson reading that, it sounds like we're tripping off the Avalon and the Burin, so we're going to be isolated from the rest, so maybe should we all move to the west coast or what are we to take from that, as a layperson reading that?

MR. HUMPHRIES:

A. Well, again, that is a short-term trip, no differently than what happens on the system today and it's happened for the past 40 years.

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We have an under frequency load shedding scheme and it's our first line of approach when we go through a generation loss. That is definitely not a utility norm in North America, you know. Under frequency load shedding are three or four tiers down the attack plan before it -- but it is priority one in Newfoundland and when we -- if we lose a unit at Holyrood, there's an under frequency load shedding scheme in place where we trip feeders to remove loads to protect the integrity of the whole system. If we didn't do that, the whole island would go black. So this is -- we're talking about the same type of arrangements for the loss of the bi-pole. We would do the same thing. If we didn't have these procedures in place, the whole province would go black. And these are -- they're not frequent events. These are events that are probably going to occur once in ten years and from an icing perspective, once in 50 years as a minimum. But there will be other events that will -- with the HVDC link, the equipment problems, converter problems that could end up in a trip of the system. It will be short in

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duration, but it will happen and when that happens, we will have to -- if we lose both poles and whether it's a line problem or a converter problem, we will have to revert to these special protections to preserve the integrity of the system. It's no different than -- we will not be doing -- now, we can be doing that six or seven times a year. We have done it as many as 12 or 13 times a year.

GREENE, Q.C.:

Q. Is there a target -- does Hydro have a target that it uses for performance measures for the number of under frequency trips?

MR. HUMPHRIES:

A. We've been trying to keep it to six, yes.

GREENE, Q.C.:

Q. And was that a reduced target and you had to enter into arrangements with customers to reduce the number of under frequency trips?

MR. HUMPHRIES:

A. Well, I mean, from the perspective of entering into arrangements with customers, the actual loads in our under frequency load shedding scheme, there are some industrial loads there. The paper mills were big contributors, where

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they would voluntarily -- we would trip non-essential equipment there and that made up a portion of the load, but there's also a number of Newfoundland Power feeders that your home and my home may be on and there are times that your lights go out and they're out for 20 minutes or half and hour and there's no obvious problem around your neighbourhood and that's quite likely what's happened because of the under frequency load shedding and through the luck of the draw, you're on one of those feeders that day and you get tripped. That's been a -- you know, a fact of life for Newfoundland for 40 years now and like I say, it's not the norm or even accepted in other jurisdictions, but it has been, in my view, one of the most significant contributors to our overall system reliability and performance in this province for the past 40 years.

GREENE, Q.C.:

Q. And one of the ways of dealing with that would be through interconnection agreements that other utilities can take advantage of?

MR. HUMPHRIES:

A. The under frequency trips for these normal

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events, like something like the trip of a 150 megawatt generator, they will not exist in the Interconnection arrangement. It just won't happen.

(3:15 p.m.)

GREENE, Q.C.:

Q. Because of the fact you have an interconnection?

MR. HUMPHRIES:

A. Yes, yes.

GREENE, Q.C.:

Q. Okay. There's two additional points on this issue. Can we just go -- well, I don't know if we need to, but in PUB-Nalcor-174, you stated that you would not be -- it is not your plan to install any of the additional combustion gas turbines to deal with reliability and I was a little confused based on some of your answers yesterday and today if it's still your current plan. Do you plan to either install any additional gas turbines to deal with this reliability issue or not?

MR. HUMPHRIES:

A. Take it back -- I'll back up. Let's go back to -- if we could go back to our Table 5 in

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Exhibit 106 again, where we talk about these level of unserved energy? And our premise moving forward of maintaining reliability at least at levels consistent that we experienced today, and if you look at the first line in Table 5 -- it's page 23 of 34. If you look at the first line in that table, the Isolated island, and we look at the year 2012 and year 2012 is representative of where we've been for the past long time, number of years, 20 years, and you look at if we had a common mode failure, and that means that we lost both transmission lines TL202 and 206 from Bay D'Espoir to Sunnyside at the same time at the worst possible time, which has a probability of two percent right now, or two to four percent, which is higher than the probability of the loss of a Maritime link, even using the 1 and 50 year design, we would experience an unserved energy in the range of 80,000 megawatt hours. So when we look at then we move down into the second block there, the island interconnected bi-pole option and we look at the numbers that -- starting off at 14,000, peaking at 93 and then coming down,

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and they will moderate at that 50,000 level in the future because that's -- as we start to bring on generation, every couple of years we're bringing on additional combustion turbines, so those unserved energies would moderate in that area. So from the perspective of where we would be then compared to where we are today, that's -- they do offer a comparable level of service. The probability of the loss is lower. The magnitude -- the maximum magnitude of unserved energy, if that happened at the worst possible time, is comparable. So that, based on that, that's where we get to no generation. If that is not deemed appropriate, the right way to go about rectifying the problem in our view is to add additional CTs or advance the CTs that are already in the plan. Increasing our line design does nothing for that.

GREENE, Q.C.:

Q. So your position, as I understand it, is that your analysis compares the proposed new system with the current arrangement and it holds us indifferent. We will be no better off.

MR. HUMPHRIES:

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A. But we will be no worse.
GREENE, Q.C.:
Q. Or no worse off, so -
MR. HUMPHRIES:
A. That's correct.
GREENE, Q.C.:
Q. So this idea of the interconnection and the idea that we may be a bit better off is not reflected in your analysis. In fact, your minimum standard is bring us at least -- the in-feed will keep us in the same place we now are?
MR. HUMPHRIES:
A. That's right. And that's based on the single -- I'll call it the single in-feed case and I know we're not supposed to be talking about the Maritime link, but it's out there and that will make a significant difference.
GREENE, Q.C.:
Q. Okay. Can we go to MHI-Nalcor-24, please? And I guess this goes to the Maritime link. The answer to the question was that the system is designed to obtain the required level of reliability with the island generation facilities. Any additional reliability as a

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result of the Maritime link has not been factored into the analysis. So let's deal just without the Maritime link, and in fact, has any information been provided by Nalcor in this reference question dealing with the Maritime link or the technical standards relating to it or how would it contribute to reliability in any way?
MR. HUMPHRIES:
A. Yes, there has.
GREENE, Q.C.:
Q. Information to this Board about the -
MR. HUMPHRIES:
A. Well, Exhibit 106 addresses the Maritime link.
GREENE, Q.C.:
Q. Have you provided any information as to what the technical requirements of the link would be to allow a technical assessment as to whether it would be available and meet the reliability requirements?
MR. HUMPHRIES:
A. No, we have not.
GREENE, Q.C.:
Q. No. So the only reference is your statement in Exhibit 106 relating to it?

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MR. BENNETT:
A. I think in this context, just to outline our rationale, the availability of import capacity from the Maritime Provinces is a significant source of generation for the island.
GREENE, Q.C.:
Q. Maybe I'm not reading the answer correctly or the other RFIs I can bring you to. Our understanding was that from a reliability perspective, what you are designing the system for was to reach all reliability criteria without consideration of the Maritime link. Is that correct? The Maritime link, in fact I think the expression was, it's gravy. It's extra. We don't need it. It is not required to meet the required reliability for the island. Do you remember the gravy expression?
MR. HUMPHRIES:
A. Not directly, but it may have been used, but from the perspective of your point, yes, that is correct. It will not be required, but if it were there, it offers a benefit and if it were there, the whole question of 1 to 50 line design versus the 1 to 150 comes into question. In the event that it is not there

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and we still only have a 1 to 50 year design criteria, from our perspective, the best bang for your buck, if you look at it from that way, for reliability is to add combustion gas turbines on the island.
GREENE, Q.C.:
Q. And that's where I guess I was earlier -- just a moment ago that I wanted to be sure I understood your position because you referred to that just then and you did yesterday, but if we go to PUB-Nalcor-174, you say it is not part of your plan to install gas turbines. So are you saying you've changed that and that is what you will do or you're saying you -- if anybody wants you to, you will consider it? I'm not sure what you're saying.
MR. HUMPHRIES:
Q. We are open -- in the event that the Maritime link did not progress, we would be open to discussion, yes.
GREENE, Q.C.:
Q. So if the Maritime link, which is not required to design the reliability of the system and all the information you've given to the Board is based on without the Maritime link in terms

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of reliability, you would not put in gas turbines either? If there is no Maritime link, will you consider adding gas turbines to address reliability?

MR. BENNETT:

A. Maybe I'll try the question another way, and I guess ultimately, this gets to the fundamental question. If Hydro were to bring forward a capital budget request for the combustion turbines within the existing criteria used by the Board, I guess the Board would have to consider whether it would approve that.

GREENE, Q.C.:

Q. But I guess before the Board even gets to consider it, Nalcor has to make a decision whether it thinks it's prudent and then they ask the Board to approve it. So, I'm asking you -

MR. BENNETT:

A. Okay, and we -

GREENE, Q.C.:

Q. - will Nalcor -- is Nalcor considering adding gas turbines?

MR. BENNETT:

A. So based on the information we have before us,

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based on the information that we presented in Exhibit 106, based on an assessment of the existing system, we do not see a basis for bringing forward additional combustion turbines. We think the path we're on is a prudent one and in the interest of our province's ratepayers.

GREENE, Q.C.:

Q. Thanks. I was just uncertain where you've referred to it a few times now, well, we can solve the problem with gas turbines, but that is not what you're proposing?

MR. BENNETT:

A. And you're right, that is a technical solution if it were deemed that a different standard of service were required on the Interconnected Island system, in the absence of the Maritime link, then our view is that the combustion turbine solution is a good solution.

GREENE, Q.C.:

Q. And I think you've answered the last question. If there is no Maritime link, you're still really comfortable at 1 in 50? Is that what you're telling us?

MR. HUMPHRIES:

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A. I can't hear you. Could you speak up?

GREENE, Q.C.:

Q. Oh, sorry. If there is no Maritime link, are you still comfortable with the return period of 1 in 50 years for the HVDC transmission line?

MR. HUMPHRIES:

A. Yes, we are.

GREENE, Q.C.:

Q. Okay. So, MHI's recommendation is not going to be considered at all by Nalcor as it moves forward to DG3 with respect to the return period?

MR. HUMPHRIES:

A. We've considered it, but we feel our solution is the best, in the best interest of the ratepayer.

GREENE, Q.C.:

Q. And you are aware of the other lines that are being built to the 1 and 50 -- and we'll hear more about that from MHI tomorrow, that their new bi-pole is and that the other lines in Ontario and Quebec are as well. They're being -- so is it because of cost, we can't afford it?

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MR. HUMPHRIES:

A. It's a combination of cost and the relative improvement in reliability that that cost brings, overall reliability, just not trip to transmission, but overall ability to be able to serve the customers' load.

GREENE, Q.C.:

Q. The cost of enhancing to the 1 in 150 year return period, we've already heard, is about 150 million dollars. That's about a three percent of your total cost of the project. So in light of the fact it's such a small percentage of your overall cost, you're that confident that your totally right on reliability, that as we sit here with a lower return period than in other provinces, as we sit here without gas turbines and as we sit here with the under frequency load shedding, I'm just -- you've made the decision on the basis it's too expensive for us to pay and that you're really right on reliability?

MR. BENNETT:

A. I think when you look at the efforts that have gone into meteorological modelling, the design limits that we're using, both on the Avalon

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and elsewhere on the system, as well as the special consideration that's being given to the Alpine regions, the observation that our current design standards go well beyond the loading criteria that are outlined in the CSA standard for this part of Canada, the observation that we have the highest ice loading generally speaking in southern Canada, we think that we have an appropriate level of reliability designed into the system.

MR. HUMPHRIES:

A. Just further to that, I guess from the perspective of it's only 150 million dollars, it's only three percent, I look at it from the perspective of yes, it's only 150 million dollars, but looking at where we can achieve the maximum customer benefit for that 150 million dollars.

GREENE, Q.C.:

Q. But obviously, I guess, it must be a judgment call and that's one of the issues for Newfoundlanders listening to this debate. We have an expert from outside the province coming in and saying the return period is not good enough. It's not high enough and when it

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comes to reliability and keeping the lights on, I guess, there's two things very near and dear to ratepayers' hearts. One is what they're going to pay for the power, but boy, even higher than that is making sure the lights come on and the lights stay on. So, thank you for your frank answer about where you are with the -- you do not agree with MHI's recommendation. I guess that's something that, and I understand from your answer, you're not even willing to consider it as you move forward to DG3. So that's -- I think we've probably covered the topic as far as we can and it may be a good time to break at this point.

CHAIRMAN:

Q. Okay. We'll take a break for a few minutes.

(BREAK - 3:29 P.M.)

(RESUME - 3:49 P.M.)

CHAIRMAN:

Q. And here we are. Now I understand you still got some -- we shall await you.

GREENE, Q.C.:

Q. Thank you, Mr. Chair. I'd like to move to another topic now, the AC Integration Studies.

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Yesterday in your presentation, you indicated that the full integration studies for the new configuration with Muskrat Falls proceeding first will be complete by DG3. Is that correct?

MR. HUMPHRIES:

A. Yes, that's correct.

GREENE, Q.C.:

Q. Previously you had advised the Board that they will be available in November past and then when the Board asked in December had they been completed, you advised that they would be completed in March 2012. Are you still on target for March 2012?

MR. HUMPHRIES:

A. We hope to be, yes.

GREENE, Q.C.:

Q. Can you explain why it's taking so long to do these integration studies? Obviously they've taken longer than you had anticipated.

MR. HUMPHRIES:

A. Yes, they've taken longer than we've anticipated and they have -- these are studies that are not being done by us. They are being done by SNC Lavalin as part of the overall

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EPCM contract and we were probably later getting these studies off the ground than we had anticipated and we have had involvement of some of our technical people in the process along the way. So it just hasn't moved as quickly as we had thought it would.

GREENE, Q.C.:

Q. You indicated yesterday as well that you had done previous studies on system integration. Some were done in 1998 when we had the proposed Gull Island development and Sales West, and in 2008 when you were looking at the 1600 megawatt multi-terminal line with one terminal in New Brunswick and that had provided you a level of comfort that you had sufficient information for DG2 purposes. Is that a correct rephrasing of what you said?

MR. HUMPHRIES:

A. That's correct.

GREENE, Q.C.:

Q. When did you make that assessment that you had sufficient information available on system integration to allow you to proceed?

MR. HUMPHRIES:

A. Shortly after I would say that we finalized

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our focus on the Muskrat Falls Labrador-Island link scenario, and that would be late 2009, early 2010.

GREENE, Q.C.:

Q. When the Board asked you about the completion of the system integration studies, you didn't advise or provide information with respect to how the previous integration studies met your criteria for DC2 or with respect to the new Muskrat Falls configuration. I was just wondering why not.

MR. HUMPHRIES:

A. I don't know whether we advised. The studies were filed as exhibits and -

GREENE, Q.C.:

Q. But when the question was asked as to when the system integration studies would be completed for Muskrat Falls, there was no indication in the response that you had sufficient information, that you didn't need to do them or that -- and in fact, I'm going to come to you also suggested you do not anticipate anything material coming out of these studies that would affect the project definition from DG2 to DG3.

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MR. HUMPHRIES:

A. I don't know if there was any particular reason why we didn't -- I guess we answered the question. The question was asked when would they be completed and we gave the answer. That's -

GREENE, Q.C.:

Q. Yeah, and you didn't go on to say "and we really don't need the answer because we already got the information"?

MR. HUMPHRIES:

A. No, we did not.

GREENE, Q.C.:

Q. Okay. You indicated that based on the previous work, you thought there was sufficient information available to move through DG2 with a new configuration, which is Muskrat going first. Is that correct?

MR. HUMPHRIES:

A. Yes, that's correct.

GREENE, Q.C.:

Q. In the change, which was a change when Muskrat was advanced to proceeding ahead of Gull Island, what additional work did you do to verify and to validate what the implications

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would be on the overall project layout moving to that new proposed configuration, apart from system integration?

MR. HUMPHRIES:

A. Well, apart from the system integration studies that -- you mean based on the previous studies or the studies that were being -- anything we did to close the gap? Is that the question you're asking?

GREENE, Q.C.:

Q. No, I guess I'm trying to get a feel for how big a deal it was. You had all this previous work done where Gull was going to be developed before Muskrat, a couple of different scenarios. One was Sales West through Quebec, another was through this idea of going through New Brunswick. But then in the spring of 2010, the focus changed and it was advanced Muskrat first, Gull second.

MR. HUMPHRIES:

A. Yes.

GREENE, Q.C.:

Q. And what did Nalcor do as a result of that decision of change in focus to look at the implications of moving to Muskrat ahead of

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Gull?

MR. HUMPHRIES:

A. From the perspective that -- just for a minute go back to the 1998 studies. The 1998 studies that were completed, while they were a Teshmont study, we did have four of our engineers seconded to Teshmont during that period and they actually did the computational work and were present during the assessment of the results. So we did have four people that were intimately familiar with the studies of 1998 and in fact, two of those individuals are still working in the same area. So, they were familiar with the models to be able to do some preliminary analysis, to look at things like advancing Muskrat Falls, putting in the transmission connection and while not completing a full assessment, getting the feel of comfort that there were not significant. It was by no means a complete integration study, but it gave us that level of comfort to know that this looks very similar.

GREENE, Q.C.:

Q. So you're talking about system integration studies and I guess my question was a bit

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broader. Apart from system integration, what types of things did Nalcor look at to reflect the change in the construction schedule from Gull, one, Muskrat, two, to the reverse?

MR. HUMPHRIES:

A. Okay. Mr. Kean, I think, would probably be better.

MR. KEAN:

A. Yes, it's Jason Kean. I'll refer you to PUB-Nalcor-9.

GREENE, Q.C.:

Q. Okay.

MR. KEAN:

A. Page -- actually the previous version, not the addendum. So pages two through five provides some clarity on some of the studies that were undertaken in the period of 2009 through 2010. Listed there beneath the subheading of Muskrat Falls reports, you see a review of variance from which the current configuration of Muskrat Falls was selected, the move of the facility to the south side of the river, given that the Black Rock Bridge across the Churchill River was in place. Further, there was some work done on spillway design review.

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So over the -- I guess in summary, the period of 2007 to '09, some critical areas were studied to facilitate better advanced knowledge of Muskrat.

GREENE, Q.C.:

Q. So there were -- because of the change in the configuration, Nalcor did have to study the implications of that on various aspects of the project and you needed those results before you moved through the Decision Gate 2?

MR. KEAN:

A. Yes, that is correct. One of the studies that was undertaken, as listed on page three, if you just go down, was to look at the review of impacts of earlier construction on Muskrat Falls -- of Muskrat Falls on Gull Island later. So we did understand, evaluate the implications in that regard.

GREENE, Q.C.:

Q. And another study, for example, you would have done was to optimize the generation from Muskrat with Muskrat being developed ahead, so that was additional studies with respect to the optimization for Muskrat being built first? That's just another example of

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something you looked at?

MR. BENNETT:

A. Yes, they were looked at, but there was information available from previous studies that showed production from Muskrat Falls with and without Gull Island. So those studies had previously been completed.

GREENE, Q.C.:

Q. And then when you changed the configuration for Muskrat, you looked at it again, and I'm trying to understand if it was necessary to do that amount of work and to have those studies completed, even though you had the previous work done in '98 and 2010, system integration was different and you didn't need to have it done because the other previous studies, with the configuration, the earlier configuration was valid enough for you. I'm trying to understand the difference.

MR. BENNETT:

A. I just think from a global perspective, I don't think you can draw an engineered conclusion from one group of studies to compare to another group of studies. The specifics of each situation, the factors under

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consideration in each study had to be looked at individually and consideration has to be -- a conclusion has to be drawn from the specifics.

(4:00 p.m.)

GREENE, Q.C.:

Q. So it was that various aspects were deemed necessary to look at it because you changed the configuration. Mr. Kean was -- it was good enough of him to bring to all of these studies that you actually did do with the change in the configuration, but system integration wasn't deemed important enough to have that updated to reflect the previous configuration for DG2?

MR. HUMPHRIES:

A. As we said before, based on our previous studies and our familiarity with those and the fact that we had in-house people very familiar with those studies and the abilities to be able to represent the new configuration from an integration, system integration perspective, we did enough preliminary work, yes, to determine that we did not feel that that was critical to DG2.

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GREENE, Q.C.:
Q. But in any event, they will be complete for DG3 and any potential cost identified or changes in project definition as a result of those studies and therefore any changes in the project cost, all of that will be reflected in our new DG3 project definition, new project DG3 cost schedule and estimates, et cetera? Is that correct?
MR. HUMPHRIES:
A. Yes, that is correct.
GREENE, Q.C.:
Q. And we won't -- the full update on the AC integration studies are available in March, but the full impact on the cost estimate and the schedule, et cetera, will not be available until we go through DG3, which is anticipated to be midyear?
MR. HUMPHRIES:
A. Yes, that's my understanding. Jason can confirm that.
MR. KEAN:
A. Yes, Jason Kean. That is correct. It's an extensive process to pull together the cost estimate as we discussed yesterday.

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GREENE, Q.C.:
Q. Okay. Just moving to a new topic and it's the power purchase agreement which is Mr. Goudie. Just a few questions to explain the nature of that contract and I know Mr. Johnson has already asked a number of questions. I just have a few additional ones. That contract or the agreement between Hydro and Nalcor has not been finalized, has it?
MR. GOUDIE:
A. That's correct. The agreement is not finalized.
GREENE, Q.C.:
Q. So when we talk about these terms, these are anticipated terms. Is there even a term sheet for it?
MR. GOUDIE:
A. Not that I'm aware of.
GREENE, Q.C.:
Q. Okay. So when we talk about the terms of the PPA, it is what you use for your analysis or what you -- or what you anticipate is going to be reflected in an actual contract or where are you getting the terms from?
MR. GOUDIE:

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A. It's just a generalized reference, the term PPA, power purchase agreement, with respect to the parameters that we used in our modelling for DG2.
GREENE, Q.C.:
Q. So it may -- at the end of the day, it may not reflect what you've used in your analysis? Is that what you're saying?
MR. GOUDIE:
A. Could you repeat that? Sorry, I'm having trouble hearing you.
GREENE, Q.C.:
Q. This is what you use for the analysis, for your financial analysis, and whatever the real terms are will be reflected when the power contract is actually put in place between Nalcor and Hydro? Is that correct?
MR. GOUDIE:
A. That's correct.
GREENE, Q.C.:
Q. Okay. So if I were to ask you, the anticipated term would be the term that you use for your financial analysis? Is that correct?
MR. GOUDIE:

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A. Yes. We used a 50 year term.
GREENE, Q.C.:
Q. Sorry, was it 50 or 60?
MR. GOUDIE:
A. We used a 50 year term for the analysis.
GREENE, Q.C.:
Q. And the term anticipated for the PPA to recover the cost?
MR. GOUDIE:
A. Was from 2017 to 2067.
GREENE, Q.C.:
Q. The price that we've talked about to recover the cost of the full analysis period, the 76 dollars a megawatt hour escalating at the rate of two percent a year over the entire 50 year period, is that what was built into the financial analysis?
MR. GOUDIE:
A. Yes. Well, the 70 -- the reference to 76 dollars per megawatt hour would be a 2010 dollar figure and that would escalate from that base.
GREENE, Q.C.:
Q. And for the analysis purposes, two percent was used?

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MR. GOUDIE:
A. Two percent was used, yes, that's correct.
GREENE, Q.C.:
Q. Okay. You don't know what's going to be in the actual PPA, but this -
MR. GOUDIE:
A. The two percent was chosen as the midpoint to the Bank of Canada inflation target range, between one and three. So it would be expected to be two.
GREENE, Q.C.:
Q. But again, it was just used for financial analysis to illustrate what it could look like?
MR. GOUDIE:
A. Yes, that's correct.
GREENE, Q.C.:
Q. Okay. It's been referred to as a take or pay contract. What does that mean?
MR. GOUDIE:
A. It would basically mean that regardless of the amount of energy that Hydro would need, it would still have to pay the contracted revenue.
GREENE, Q.C.:

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Q. So once the terms are agreed, regardless of the amount of power that's taken, Hydro would have to pay Nalcor a fixed amount?
MR. GOUDIE:
A. That's the way we've modelled it at this time.
MR. BENNETT:
A. Just to clarify, Ms. Greene, when you said "when the terms are agreed." Are you asking us to speculate on what the terms of the PPA are or what we used for our analysis? Those are two very different things.
GREENE, Q.C.:
Q. Yeah, and I should say, for the purposes of the analysis, and I wanted to make the distinction earlier that we're talking about something that you created for the purpose of the financial analysis. At the end of the day, the PPA will be whatever the PPA is negotiated and because it's done on a PPA basis and not a cost of service basis, that particular arrangement, the costs that go into it will not be regulated by the Public Utilities Board, will they?
MR. BENNETT:
A. No, that's right, they won't.

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GREENE, Q.C.:
Q. Do you know if that will be the same arrangement in Nova Scotia with respect to regulation of the Emera project in Nova Scotia?
MR. BENNETT:
A. I understand that a proceeding is contemplated before their Utilities and Review Board. I don't know the terms of reference of that reference.
GREENE, Q.C.:
Q. But would it be on the basis that Nova Scotia Power -- I believe one of the terms of the term sheet was that they had to get approval from the regulator.
O'REILLY, Q.C.:
Q. Mr. Chairman, I don't know how informative this is going to be to inform the reference question about what's going to take place and what the reference question or whatever the Public Utilities Board of Nova Scotia is going to be doing. I mean, it's just that it's an area of speculation and I don't think that -- I think it's putting too much on these witnesses to expect them to respond to that.

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GREENE, Q.C.:
Q. No, that's fair. It's only to -- I was trying to explain what is the difference between a PPA and the role of the regulator and the cost of service. I don't have to go to Nova Scotia where I understand they're doing it on a cost of service basis, right.
O'REILLY, Q.C.:
Q. I think you probably have the answer to it.
GREENE, Q.C.:
Q. But so the terms that we're talking about, the 60 -- this was all used for the financial analysis and I guess it draws me to another point. Everything we've talked about actually, DG2, the project definition and the cost estimates, may not be the reality of where we end up, are they, any more than the power purchase that we just talked about is? Because at the end of the day, we will have a different project definition than we're looking at. We will have a different cost estimate than we will look at. We may or may not have a Maritime link that may or may not affect reliability. We may or may not have a Maritime link where the revenue received gets

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applied to any of this as it applies to Newfoundland. So for the purposes of the reference before the Board and the information we have as of DG2, isn't that also correct as what you said about the PPA?

MR. BENNETT:

A. Well, I think it's fair to say that the Decision Gate process, the project definition that we have, the general concept, the notion that Muskrat Falls as a generation source and the Labrador-Island transmission link as being the preferred supply option are being evaluated in this proceeding and I guess, you know, those basic concepts are the ones that are moving forward in our continued work. So I think that -- you know, I think that those are -- that those fundamental constructs will remain through our project definition unless, you know, something changes fairly dramatically.

GREENE, Q.C.:

Q. But again, it's DG3 where we will see the project definition and full revised capital cost estimates, et cetera, but anyway -

O'REILLY, Q.C.:

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Q. We've been there.

MR. BENNETT:

A. I would characterize it as refined, as opposed to revised. It is a continuing evolution in our project planning, project definition preparation for project execution.

GREENE, Q.C.:

Q. And like that issue we just talked about that's outside of our purview, there's other issues that aren't before the Board because of the terms of bank which impact on where we end up.

MR. BENNETT:

A. I think that there are some other questions, I would agree.

GREENE, Q.C.:

Q. In the financial analysis that you did for the power purchase agreement, was there any contemplation of changing in price? It was just all you did was escalate it by two percent and you assumed there would be no off ramps. If there was any change in market conditions relating to pricing that Hydro would be locked in to paying this as a take or pay?

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MR. GOUDIE:

A. If Hydro required less power than provided for in the supply arrangements, then Hydro and Nalcor would work to monetize that differential and supply requirement in order to minimize any ratepayer benefits.

GREENE, Q.C.:

Q. Remember I said earlier sometimes I ask a question and I expect two and two is four and I get three. You just did it to me, Mr. Goudie, so can you explain that a little bit more to me?

MR. GOUDIE:

A. Well I mean, if Hydro is contracted, say in the first year to take 2 terawatt hours, it only requires say 1500--oh I'm sorry, gigawatt hours, say 2 terawatt hours and it only takes one and a half, then you would expect and the assumption has been throughout that given that Hydro has the take or pay arrangement, that that 500 gigawatt hour differential, then Hydro would try to ensure that it disposes of that energy in a way to minimize the obligation of the ratepayer or to help to mitigate, I should say, yes.

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GREENE, Q.C.:

Q. But the first, as a normal take or pay, Hydro would still be committed for it?

MR. BENNETT:

A. Right, and maybe to build on my previous comment, I mean that's one of the things that could change once we actually get to a scenario where we have a PPA and then you can explore the terms of the PPA and understand how, you know, any surplus energy would be monetized. That would be a question to be resolved in the PPA. It's not one before us because our analysis is the terms of reference, all the costs for both Muskrat Falls and the Labrador-Island Transmission Link are recovered from the Domestic supply. That's one of those evolution things that I was thinking about earlier.

GREENE, Q.C.:

Q. And that was one of the things that I was referring to where I said what we're talking about may not end up being a reality.

MR. BENNETT:

A. But I think maybe to build on that, I think that what we're seeing here is what we expect

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to be a very good definition of that reality is a fundamental question, you know, do we conclude that Muskrat Falls and the Labrador-Island Interconnection is a preferable option to one where we see dependence on fuel and the Isolated-Island scenario, I mean, that's the fundamental question that we have to reconcile. How we evolve that alternative in the future and how we refine it to continue to advance it, that will be reflected in our future work.

GREENE, Q.C.:

Q. Moving to another topic it's a follow-up to questions Mr. Johnson asked yesterday with respect to the environmental upgrades at the Holyrood Thermal Plant. There's approximately six hundred million dollars cost included in the Isolated-Island option to add scrubbers and precipitators and Low NOx burners to the Holyrood plant in the Isolated-Island option and I just wanted to explore with you what those upgrades were to address. My understanding is that with burning lower sulphur fuel, a .7 percent fuel, Holyrood will meet all environmental requirements with

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respect to SO 2 for the life of the plant at, even at full load, is that correct?

MR. BENNETT:

A. Yes, that's my understanding that SO 2 emissions are addressed with low sulphur fuel based on the regulations we currently see.

GREENE, Q.C.:

Q. Okay. With respect to particulate, my understanding is of a low sulphur content fuel, burning that fuel for the life of the plant will address all of the targets Hydro had established for particulate?

MR. BENNETT:

A. While they may address Hydro's targets, they don't address the commitment made on the Province's energy plan and the commitment made to the residents in the area where particulates have been an ongoing concern and I guess that's where we get to the commitment to install additional pollution controls on that facility.

GREENE, Q.C.:

Q. And you jumped ahead of me, so in terms of that, I take from your answer--am I correct in stating that from a utility perspective,

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there's no legislative or environmental legislative or regulatory requirement that would require the utility to put in those pollution control upgrades at this point in time prior to knowing what the environmental regulations would be for the future. For example, are you now complying with your Provincial Certificate of Approval?

(4:15 p.m.)

MR. BENNETT:

A. We are complying with that certificate of approval today.

GREENE, Q.C.:

Q. And all environmental legislation and regulations that are known for the foreseeable future, we'll come back to what may happen -

MR. BENNETT:

A. Well I think there's a clear statement of policy by the Province of Newfoundland and Labrador and it is an environmental one, that there is a clear statement of policy that in the event that the system remains isolated and Holyrood continues to operate, that Nalcor and/or Hydro will be directed to install pollution controls on that facility, so I

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mean, the energy plan is very clear, so on that point, I would look at that statement of policy and the direction provided there as being ultimately direction to us.

GREENE, Q.C.:

Q. So the reason that Nalcor is doing--putting in these upgrades for 600 million dollars is in response to a policy directive from government, which, of course, as government and as a shareholder they have every right to make.

MR. BENNETT:

A. Right.

GREENE, Q.C.:

Q. Now looking at what you're installing, what do precipitators and scrubbers actually address?

MR. BENNETT:

A. Those two pollution controls address particulate emissions as well as sulphur dioxide emissions and one thing that we do note is that with the installation of those pollution controls, we do have the ability to move back to higher sulphur content fuel for the Holyrood facility.

GREENE, Q.C.:

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Q. On the issue of the fuel, a question I wanted to ask, again Mr. Johnson asked this yesterday and in reading the transcript I wasn't totally clear on the answer, but the question was had a cost benefit analysis been done to show whether it was cost effective to install the upgrades or to use the lower sulphur content fuel and it was Mr. Humphries who answered the question and my understanding from the answer is that it is not cost effective to install the pollution control upgrades, it is more cost effective to continue to use the lower sulphur content fuel which does address all current requirements. Did I state that correctly? I can take you to the transcript?

MR. HUMPHRIES:

A. No, you may have stated it--the intent of the question and I may not have addressed the question properly, but what I intended it to mean at that time from the perspective of the continued operation of Holyrood with the addition of the pollution abatement equipment as opposed to building a new facility today with a different fuel source, it was cost effective to continue to operate Holyrood to

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the end of its current life expectation with the additions, as opposed to putting in a new combined cycle facility that would burn No. 2 fuel and have lower emissions.

GREENE, Q.C.:

Q. That's helpful, it helps clarify the comments which--in terms--have you done the other analysis then of looking at the .7 percent fuel because the intent is to put in the pollution control upgrades and to go to then the 2.2 percent sulphur. Have you done the analysis to show what is more economical?

MR. BENNETT:

A. Burning the low sulphur fuel doesn't address the policy direction from the province, so we have not studied the implications of continued use of low sulphur fuel as an alternative to the installation of pollution controls.

GREENE, Q.C.:

Q. So if you look at the CPW for the Isolated-Island option, there is 600 million dollars in there for the environmental upgrades, which is one of the capital cost components. There's the other cost components as well, but I believe you indicated from the analysis it

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shows the biggest driver is the fuel component at 70 percent.

MR. BENNETT:

A. That's right, yes.

GREENE, Q.C.:

Q. So barring significant change in the fuel component, there's very little that would draw the Isolated-Island option down in isolation if there was only one factor, is that correct?

MR. BENNETT:

A. I'm not sure I follow.

GREENE, Q.C.:

Q. The preference for the infeed over the isolated depends mostly on the fact that so much fuel is burned to the Isolated-Island option.

MR. BENNETT:

A. Fuel is the majority, the significant majority of the total CPW for the Isolated alternative, yes.

GREENE, Q.C.:

Q. So while we have--we've looked at a number of sensitivities and I won't go there now, but it does illustrate your analysis, in fact, it's one of the first times I've seen CPW analysis

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where it was all positive, because usually I've seen a range, some are negative and some are positive, but the ones that Nalcor filed all showed a preference for the infeed. If we look at one factor is isolation, there's not much you can do to shift that preference because of the huge fuel component in the Isolated-Island, is that correct?

MR. BENNETT:

A. Yes, you would have to do something with the fuel bill.

GREENE, Q.C.:

Q. Right.

MR. BENNETT:

A. Yes.

GREENE, Q.C.:

Q. And how do you use the sensitivities, we've had a little bit of discussion around it--the purpose of sensitivities is to illustrate the degree how--what are the key variables and what impact a change in a key variable can have on your outcome, so therefore, helps with your assessment of the risk, is that -

MR. BENNETT:

A. I'd generally agree with that, yes.

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GREENE, Q.C.:

Q. Okay. So in coming to looking at the 2.2 billion dollar difference on the basis of what's in the CPW, analysis submitted in support of the infeed option, when we look at some of the sensitivities, we see that changes in those--and key variables can significantly impact the outcome and one of the biggest variables is fuel, which is the uncertainty that it's, we're trying to forecast out over the 57 year period and we talked about that earlier, another uncertainty is the construction costs and we talked a little bit of that yesterday where we looked at the sensitivities for the 25 percent increase in capital cost and we saw that if capital cost for the infeed, including the Link, go up by 50 percent, then the preference is essentially eliminated, right, so if we have a fifty percent overrun, both options come back roughly being equal. And we looked at--so capital cost is one of the drivers that is significant. We've looked at the load, we see if there's a drop in the load of 880 gigawatt hours as slight more, again it has a

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significant impact and we're down again to they're almost equal. One of the questions that I've heard and that I wanted to put to you is we have some big key inputs. I just mentioned three of the key ones we've talked about here, we have load, fuel price, construction costs and of those, I guess fuel is the most risky that you don't have control over. How do you weight that when you do this analysis with this length of period and you have such potential variability in some of the key assumptions?

MR. BENNETT:

A. I think another way of stating that is if we look at sort of--your comment about the negative and positive sensitivities, and I think his phrase has been used in our analysis that the sensitivity analysis indicates a preference for the Interconnected scenario over a broad range of conditions and I think, you know, one way to characterize that is the Interconnected alternative as a robust alternative, but when you look at, you know, a broad cross section of sensitivities analyses, there is still a preference for the project.

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Now there is--we would acknowledge that there is variability in fuel pricing, but this may be an area where a forecast, that fuel is simply going to stay at the same price in real terms over a very long forecasting term, that maybe, you know, I'd be surprised if that played out in the long term, in the absence of a clearer trend, you know, we've elected to use what we think is a reasonable number. But if we look back over history, we have seen fuel prices escalate, you know, at greater than that rate over time and certainly in PIRA's forecasting period out to the middle of 20's, they're seeing an escalation rate that's approximately double that. So I guess we have to trade off collectively, you know, do we believe that fuel prices are going to moderate from where they are today and that's the fundamental question and the insight we're getting from our, you know, from the industry and from PIRA and from the other groups who are forecasting energy prices, is that does not appear to be the case.

GREENE, Q.C.:

Q. So, that's on fuel which is one of your big

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variables. So, the level of comfort that you're making this decision given the uncertainty over the length of the forecast period, you test that through sensitivities to give you a level of comfort as to whether you're making your right assumptions. I guess, one of the other factors, approaches, and I wanted to give you the opportunity to explain why Nalcor hasn't chosen it, is to look at this incrementally. I mean, we've heard comments and one of the--again, taking page from Mr. Johnson, one of the issues in the media is it's too rich, we can't afford to pay for it, you will bankrupt the Province, that type of thing. So, why don't you take an incremental approach? Why don't you put in a couple of little gas turbines or do another 170 cct's, buy us time, let's see what's happening with the load in Corner Brook. Let's see what's happening with the load down in Labrador. Let's see what's going to happen with natural gas and the impact of fuel prices. So, even though it may be more expensive in the long term with a higher CPW, you're biting off smaller bites at a time and

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you're buying time.
MR. BENNETT:
A. I guess the question is, buying time for what? I mean, if you go down that road incrementally, I think you will continue to go down that road. And what we're effectively doing by not making a decision is continuing down the isolated path. Doing so will not develop power for industrial development in Labrador. We will have no surplus generation for Muskrat Falls in that scenario. We will have to do with what we have and we will remain isolated. So, I think Mr. Martin has pointed this out on a couple of occasions, doing nothing and not making a decision, effectively is a decision. It puts us on the isolated path.
GREENE, Q.C.:
Q. So, Hydro has considered and rejected the incremental approach. It's kind of a this is the time to do it and now is the best time. If we don't do it, the water will flow forever.
MR. BENNETT:
A. There are a lot of good things at this point in time. Interest rates are attractive; the

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federal loan guarantee appears to be lined up; we have the potential for demand in Labrador. We've done a analysis comparing the cost of Muskrat Falls to the Isolated alternative. There is a CPW preference. There is a growing concern about greenhouse gas emissions. There is a fear that oil prices will continue to escalate. So, those concerns are there and we think this is a good answer.
GREENE, Q.C.:
Q. Switching hats, one of the other concerns is your load forecast shows the capacity deficit in 2015 with an energy deficient in 2021 or so. We also know that you're not where you had wanted to be with the decision to proceed with construction. What is your backup plan if you get further delayed? How will you address the capacity and energy deficits that you are now forecasting to meet, you obligation to serve? What's your backup plan?
MR. HUMPHRIES:
A. We will, on a regular basis as we do all the time, continue to evaluate and monitor the situation and compare our requirement with our capacity and energy. The 2015 deficit will be

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addressed with the combustion turbine. On an annual basis, if we get through, for argument's sake, some time later in 2012 or into 2013 and we still not--have not sanctioned Lower Churchill, that will be reflected and updated every year in our regular generation expansion issues report that we file with the Board, and there will come a point that if the schedule in service for Muskrat Falls comes out of step with our requirement, that we will have to do or develop either one of the items in the Isolated plan, or add a thermal source, depending on what the prospects are at that time for Muskrat Falls and the length of delay we could be looking at.
GREENE, Q.C.:
Q. Have you looked at doing your wind you had planned to do and advancing Portland Creek to get you over the capacity and energy -- I'm sorry, have you looked at advancing Portland Creek and doing your wind and to see how far that would take you, because you were going to do Portland Creek anyway in the infeed option.
MR. HUMPHRIES:

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A. We haven't looked at it, but in the event, like we will be redoing the generation issues report and the intent, as we didn't file a report in 2011, as everyone knows, and the intent was to file that with DG3, which is still the case. If DG3 advances beyond our normal 2013 capital budget exercise, there will be an update of the issues report filed at that time with the capital plan.
GREENE, Q.C.:
Q. I was going to say can we have an undertaking that there will be an updated generation plan and a load forecast plan filed with your capital budget--Hydro's capital budget in the summer of 2012, even if DG3 is not passed? I'm only joking.
O'REILLY, Q.C.:
Q. Okay, I'm glad.
GREENE, Q.C.:
Q. Mr. Humphries just said it was, I was just -
O'REILLY, Q.C.:
Q. You know, this process is to inform, is to reference question and not to get commitments about required filings before the Public Utilities Board on regulated activities.

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GREENE, Q.C.:
Q. The issue is the Board's regulatory oversight and one of the tools used is the generation expansion issues in a load forecast which wasn't filed with the Board in 2011 to allow them to assess it, so that's--Mr. Humphries took me there, so I couldn't resist.
MR. HUMPHRIES:
A. The intent is that we will do an update in 2021, if not at DG 3, with the capital budget submission and that will address if there are risks and concerns regarding the timing of any of the alternatives, whether it's in the Isolated or in the Interconnected, we will address those and have a plan.
GREENE, Q.C.:
Q. That concludes all my questions except the one with respect to the change in the return period and I don't know--if you haven't had time to review it, I will accept an undertaking to file the response to that question.
O'REILLY, Q.C.:
Q. In the change?
GREENE, Q.C.:

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Q. My question, when the return--at one time my understanding was that Hydro had been using a return period of one in 150 years for the DC line into the Island. My understanding was that that was changed sometime in 2010 and -
O'REILLY, Q.C.:
Q. That may be contained in a confidential exhibit, that information, but anyway, if you're finished and the Commissioners have questions of the panel, it probably would be a good time to move on. I ordinarily would probably have some questions just to clarify some things, but what I would need to do, I would rely upon getting the transcript and what I want to make sure is that when I come back, I will probably only be concerned to the extent that the questions that were asked end up in a summary of several questions for which the panel are asked to either agree or disagree, I want to make sure that--because they had some difficulty in hearing some of the things you were saying, I want to make sure that what they've said, that they're comfortable with agreeing with your summary of the question. And I will review that

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overnight and then we can decide.
GREENE, Q.C.:
Q. Well I can ask the question again, the return period designed for the line, was it ever at any time one in 150?
O'REILLY, Q.C.:
Q. No, that's not my point.
GREENE, Q.C.:
Q. That's the only answer, but anyway.
O'REILLY, Q.C.:
Q. Well do we have the answer or is it--it's in an exhibit.
MR. BENNETT:
A. So if we an take that one away and bring it back tomorrow morning, that would be great.
O'REILLY, Q.C.:
Q. Sure, they can bring it back.
CHAIRMAN:
Q. So you're finished, are you?
GREENE, Q.C.:
Q. Yes, I am, thank you Mr. Chair.
CHAIRMAN:
Q. So do you have anything you want to--additional now or -
MR. JOHNSON:

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Q. I don't know about now to be honest and perhaps tomorrow morning I'll have a look at it because it was quite an extensive and thorough examination done, taken on board.
CHAIRMAN:
Q. Madam Newman, do you have any questions?
COMMISSIONER NEWMAN:
Q. Do we want to wait -
CHAIRMAN:
Q. I'm sorry.
GREENE, Q.C.:
Q. I understand that Nalcor may wish to have some additional questions.
CHAIRMAN:
Q. Oh, okay.
O'REILLY, Q.C.:
Q. Just for clarification and what I've outlined, I'm going to review the transcript, the area where I am concerned with is the area where a number of questions are summarized, at the end there's a summary of the questions, what counsel interprets the answers to be and I want to make sure that the witnesses are comfortable with that because there was some difficulty in hearing, you know, so I just

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want to make sure that we're comfortable with that and that's it. So I will need a little bit of time tomorrow.

CHAIRMAN:

Q. So are you suggesting that we just postpone all questions until Mr. O'Reilly is finished or -

O'REILLY, Q.C.:

Q. No, I don't think so, I think if the Board has questions, we can proceed with that.

CHAIRMAN:

Q. Okay, do you have any questions?

COMMISSIONER NEWMAN:

Q. Not at this time, no.

COMMISSIONER OXFORD:

Q. Mr. Chairman (unintelligible - audio feedback) okay, whatever questions are left to be asked by the two parties.

CHAIRMAN:

Q. Okay, how about you?

VICE-CHAIR WHALEN:

Q. Is it the intent to reconvene the panel in the morning?

CHAIRMAN:

Q. Will you be reconvening your panel in the

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morning was the question, Mr. O'Reilly, or will you just be making summary?

O'REILLY, Q.C.:

Q. Well I only intended to bring back--I only asked if there was witnesses whose answers were -

CHAIRMAN:

Q. Whose answers are--there's some ambiguity or lack of clarity, you will -

O'REILLY, Q.C.:

Q. Try to get some clarify on that, I didn't intend to come back, but I mean, these people, you know, are available. If the Board requires them to come back because they have questions of the panel, we will do that.

GREENE, Q.C.:

Q. Excuse me, I understood Mr. Johnson also may have questions of the panel.

O'REILLY, Q.C.:

Q. And Mr. Johnson may have some questions too, so that's fine.

MR. JOHNSON:

Q. I think that we should preserve the panel for tomorrow morning.

CHAIRMAN:

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Q. Well okay, well I had some questions but I think in the interest of sanity, we will save all the questions for tomorrow morning, how about that? Would you find that more acceptable or--because I could stay here for another hour if you want, but I don't think I would be very popular. So let's, Mr. O'Reilly, bring back the panel in the morning and we'll continue with the exercise.

O'REILLY, Q.C.:

Q. Fine, thank you.

CHAIRMAN:

Q. All right.

Upon conclusion at 4:37 p.m.

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CERTIFICATE

I, Judy Moss, do hereby certify that the foregoing is a true and correct transcript of a hearing of the Muskrat Falls Review, heard before the Board of Commissioners of Public Utilities on the 14th day of February, A.D., 2012, in St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, NL this

14th day of February, 2012

Judy Moss

Discoveries Unlimited Inc.

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