February 13, 2012

CHAIRMAN:

Q. Good morning, everybody. I want to welcome you all here for these sessions. The word in French is "seance" by the way. My name is Andy Wells, and I'm CEO of the Board. On my left is Darlene Whelan, who is our Vice-Chair. On my far right is Dwanda Newman, a Commissioner, and on my right is Jim Oxford, also a Commissioner. I welcome everybody here this morning. I understand others will join us over the course of the next ten days or two weeks, and I understand also that we are being webcast, which is an interesting development, so welcome to - I'm sure there's a numerous viewing audience out there, a major viewing audience out there, and we hope the webcast will assist us in shedding some light on this issue.

The matter before us is a reference from the Government of Newfoundland and Labrador, which directed the board to review and report on whether the proposed development of the Muskrat Falls Generation Facility and the Labrador-Island Transmission Line represents a

least cost option for the supply of power to Hydro's Island interconnected customers over the period 2011 to 2067. I hope to be around for 2067. As compared to a specific isolated Island development. The Board's review is limited to examination of these two options; the Muskrat Falls Project, and the Isolated Island Development scenario. Upon receiving the reference from the Government in June, 2011, the Board started the process of gathering information in the form of our advise information request. Mr. Thomas Johnson was also appointed at the time as Consumer Representative, and also has been involved in directing questions to Nalcor and in seeking public input. Mr. Johnson, I'm sure there's not anybody who does not know who he is, but Mr. Johnson is here straight ahead of me, or slightly to the left, I should say. We have asked totally all the parties - over 500 questions have been asked of Nalcor, and these questions and replies to these questions can be viewed on the Board's website. Nalcor filed its required submission with the Board on November 10th, 2011.

In June, the Board also hired an independent expert consultant, Manitoba Hydro International, MHI, to assist us in our review and they were asked to review the technical feasibility and the cumulative present analysis for the two power supply options identified in the referenced question, and, of course, to do their work, MHI assembled a team of specialists with expertise in load forecasting, risk analysis, project management, utility resource planning, hydro electric and thermal generation, HDCDC engineering, hydrology, submarine cable crossings, wind power, and financial analysis, and their report was filed on January 31st, 2012, and, of course, was released publicly at that time. The Board has set aside the next two weeks for presentations and questions related to its review, and starting today, of course, Nalcor will make a presentation to the Board. Following the presentation, the Consumer Advocate will have an opportunity to ask questions, and thereafter Board Councillor and Commissioners will have an opportunity to ask questions of Nalcor. At the conclusion of

questions of Nalcor, MHI will make a presentation, and we expect this presentation will begin on Wednesday morning subject to how things proceed. As I said, that will depend on the timing of Nalcor's presentation and questions. Interested persons wishing to place a relevant question on the record may so do through the Consumer Advocate. Next week presentations from other interested parties will be heard by the Board and individuals wishing to make a presentation next week should register in writing no later than Wednesday, February 15th, 2012, directly to the Board's website. For further information on the process to be followed, and the requirements for making presentations, we'll post a schedule of the presentations on Friday, February 17th, on our website. As I say, the presentations will be webcast and will be available for viewing through the Board's website, and we will have transcripts of our proceedings posted on the Board's website daily. Nalcor and the Consumer Advocate will provide final submissions on Friday, March 2nd, 2012, and of course the

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Board will submit its final report to Government by March 31st, as dictated by the reference.

I would like to now introduce those who will be working and supporting the efforts of the Board over the next two weeks. Board Legal Counsel, Maureen Greene; Director of Corporate Services and Board Secretary, Cheryl Blundon; and Mike McNiven is our Technical Analyst on my right. If there's anyone who has questions or requires any particular assistance over the course of the review, you may direct your inquiries to Cheryl, and we will do everything we can to assist you. If you do not wish to make a presentation, you may wish to submit a letter of comment by email, mail, or on the feedback forum on the Board's webpage. The Board will continue to receive letters of comments and additional information until February 29th. It's a leap year, oh, okay. Upon receipt of all information, it will be our task as Commissioners to review the report and report by March 31st, as we said on the reference questions set out in the Terms of Reference.

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That concludes my general remarks. There are a number of other items, including some housekeeping matters which I should also like to cover. We will start each day at 9:30, except for today, I guess. The time for breaks during the day will depend on the presentations and timings. We're not hard and fast on that, so we will probably decide that collectively. There will be days when the Board will convene an evening session if necessary. Mike McNiven, who I introduced earlier is available to assist with any presentation on any electronic setup, any technical matters you may refer to Mike and he will certainly assist you. He knows precisely and exactly what he's doing at all times. The proceedings are being recorded by Discoveries Unlimited, Glenda Gibbons, under the supervision of the Board Secretary, Ms. Blundon, and will be transcribed overnight and posted on the Board's webpage for the next day. Persons addressing the panel may for the benefit of transcription services refer to Commissioner Whelan, Newman, or Oxford, by name, and myself as Chair. I was told to put

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that in there. Mrs. Blundon maintains the official record for this review with all documents format, including transmissions, and as I say, all documents and information are posted on the Board's website. The last important matter, of course, is with respect to fire safety. There are two exits in the room; at the front where you came in, and another here at the back, which leads to the Board's office corridor. In the event of any emergency, I ask you to proceed to the nearest exit and follow the signs. In closing, I would like to acknowledge the work of all participants in preparing for this proceeding. I fully realize the time frames, and I appreciate your cooperation in this matter. I think now I should perhaps turn it over to Nalcor. Mr. Thomas O'Reilly is the Board Counsel for Nalcor, and I understand he's assisted by Denis Fleming. Mr. O'Reilly, I'll turn it over to you, sir.

O'REILLY, Q.C.:

Q. Thank you, Mr. Chairman, Mr. Commissioners, this morning we're going to - Nalcor will make its presentation. We have

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making the presentation first, Mr. Ed Martin, President and CEO of Nalcor Energy Inc., and Mr. Gilbert Bennett, who is the Vice-President responsible for the Lower Churchill Project with Nalcor. The presentation by Nalcor will be divided essentially into two sections. What we will do is there will be a presentation, Mr. Martin and Mr. Bennett will deliver the presentation, and then in anticipation that there will be questions that may be directed from either the Consumer Advocate and/or Board Council. We will proceed to impanel a panel of people from Nalcor who will be in a position to respond to the questions. So it will take the form of actually two panels; one will follow the other after the presentation is submitted. So unless there's any further direction - oh, I should add, I guess, as well that the presentation that you have before you, it's undergoing a few editing changes. We expect to have hard copies of those available within the hour for circulation and delivery to the Board and for those that are in the room. So without any further ado, probably I could ask

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Mr. Martin, please.

MR. MARTIN:

A. Thanks, Tom. Mr. Chair, Commissioners, I'd like to take a few moments before I turn it over to Gilbert, Mr. Bennett, for the more detailed presentation, to offer, you know, some opening comments for your consideration. Primarily, I'd like to start out and address the question as to why do I believe this is the right time to build Muskrat Falls and a Labrador-Island link.

The first point really is if you look at the process we've followed, we have identified a need, and Gilbert will talk more about our demand needs for the province in the future, but we have identified a need. It's clearly there and we have to make a decision.

Point number two is we've done some extensive analysis of the options and we've come up with a recommendation that Muskrat Falls and a Labrador-Island link is the best option, it's the lowest cost option to meet this need over time by a number of 2.2 billion dollars, which is the cumulative present worth difference between the alternatives being

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considered. So this is not a trivial amount, obviously. There's a 30 to 35 present difference between the two options, and over time - as I mentioned, this is a present value number. Over time from a nominal perspective, this number will be even larger. So that's the basic primary simple fact of the matter is that there's a need and we have come up with a recommendation for the lowest cost option.

I'd like to add to that some additional factors. So we have a project that is the most economic to do at this particular time to meet our needs, but there are several other key points. With that decision made, I'd just like to add a few extra thoughts as to why I believe the timing is good and solid for now. First, in the analysis we have assumed in those numbers that we would only be using the power that the province needs. The additional power that would be surplus in the early days would not actually be valued for the purpose of the economic analysis. So there's additional power that's available, there's no use specified in the analysis, but it's there, and that obviously creates an opportunity -

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this surplus power creates an opportunity to meet potential demands in Labrador particularly with development of the potential mining opportunities there, as well as additional power to be used for other developments throughout the Island of Newfoundland if necessary. So the option creates additional power, creates surplus power for the province.

The second point is that an investment like this, if you look at the isolated island alternative, essentially the alternative where we head into a situation where we keep Holyrood open and we add additional thermal generation, in that particular scenario over the next period of time, many, many years, we are going to be spending a substantial amount of cash on oil and/or gas to be able to fire the thermal generation. So that's a huge amount of the isolated island cost expenditures will actually be expended outside the province, will not be here for the benefit of the province. You compare that to a Muskrat Falls Labrador-Island link, not only is it the cheaper alternative, but in addition

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to that the cash that is being spent over the next 50 years will actually be invested in an asset that belongs to Newfoundlanders and Labradorians and it will be there for a lifetime as generational asset, and I like to use the analogy sometimes that it's a rent versus buy decision. We have a situation here where we have an opportunity to rent that is more expensive than an opportunity to buy and own the asset forever.

The third thing is these benefits for a hydro project, I mean, hydro projects are inter-generational projects. I mean, these are lifetime projects, many lifetime projects. I think we like to think in terms of 100 year assets, but these are assets that last many, many, many years. They're the gift that keeps on giving when it's constructed, it's a renewable resource, and obviously will not only benefit this generation, but many generations into the future. It's clean power and what we'll see with the Muskrat Falls Labrador-Island link option and service is that Newfoundland and Labrador will be essentially 98 percent free of greenhouse gas

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emissions. We would have also addressed some of the concerns and issues that come with the nitrous oxide and other emissions at Holyrood, and we'll be in a situation where in this country and in this continent we'll be one of the leaders from a clean energy perspective with respect to electrical generation. In addition to that, I think we're fortunate at this particular time the interest rates are low. They're low for a variety of reasons with the worldwide economy in a situation where there's significant recession throughout the world. Newfoundland and Labrador, it's a bit of a turnaround for us, I think, for once in our history we're probably in the driver's seat more so than many other jurisdictions, but in any event, the culmination of a lot of what's happening worldwide has resulted in significantly low interest rates, which is a very significant component of the cost of building something like this. So we're in that low interest rate environment. How long will it last; well, indications are it's going to be several years into the future, but no one is ever sure, but we do know we're in a

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low interest rate period of time, and that's going to last - in the context of this project, it's going to be available to us at this particular time, and as the future moves on, we've seen it over time that as interest rates rise, and certainly they will at some point, it would have a very negative impact on a project like this and I think it's a good to be able to take advantage of the interest rate situation. Further comment on the interest rate situation, we have, you know - the province has actually come to an agreement with the Federal Government with respect to in addition to low interest rates, the Federal Government has also agreed for this option for the Muskrat Falls Labrador-Island link option, for the green option, they've also agreed to provide a federal loan guarantee on top of that. So not only do we have lower interest rates in general, on top of that we are going to be able to apply a federal loan guarantee which will lower the interest rates even lower, and that federal loan guarantee is tied to the Muskrat Falls Labrador-Island link green option, it's not tied to any other

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option.

In addition, from a provincial perspective, and fortunately things have - particularly with the oil revenues, things have changed in Newfoundland and Labrador, and for the first time essentially in our history we are in a situation where we have a strong revenue base driven by oil. It's a non-renewable resource. Over time, obviously, non-renewable resources go away and do not come back, but at this particular period in time we have that boost in revenue at a time when we'll be building a project of this nature. If you look at what's happened over the past four to five years, in particular, there's been three incremental oil projects; Hibernia South, Hebron, and West White Rose. Those are three incremental projects which have been agreed and put in place over the past five years, which are estimated to bring an additional revenue base of 38 billion dollars into the Province's coffer. So the timing once again is good from this project's perspective. It's happened over the past four or five years. Thirty-eight billion

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incremental dollars, and at a time when we're moving into a project of this nature, the timing once again suits the project. In addition to that, and not included in any of the economics, there are significant construction benefits for a project of this size. Particularly in Labrador, they're going to see a tremendous boost in activity, and from the province's perspective, I go back and make the earlier point, we need the power, so the cost options there's a series of benefits here, but on top of that, you know, the significant job opportunities for Newfoundlanders and Labradorians, particularly Labradorians. If you look at the tax revenge that will be generated by this project that will go directly into the province's treasury, all these benefits will accrue to the population, primarily to the population of Newfoundland and Labrador. We have in place for the first time a Water Management Agreement, and Water Management Legislation that the Province has passed, which requires any operators - any two or more operators on a single river throughout the province to come

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to a Water Management Agreement to make sure we maximize the resource availability to the benefit of the province, and that Water Management Agreement Legislation is in place and there's been a Water Management Agreement negotiated and in place between the Lower Churchill Project and Churchill Falls Labrador Corporation, which gives this particular project full access to the benefits of the very large reservoir up river, Churchill Falls, and that is a key element in making this project very viable.

We've also completed an agreement with the Innu Nation, and that agreement has been ratified by the Innu Nation, it's in place, it's there, and we're ready to go. Additional to that, if you look at a hydro plant and a Labrador-Island transmission link, these are large assets and they require expertise to build these assets, but from a technology perspective this is known technology. So we're taking on construction of a large project, but it is a hydro asset, and we understand hydro assets, this is technology that's been around for many, many, many

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decades. Similar to that, from the transmission side of things, transmission construction, it's big, it's long, but it is not complex. So this a technology we understand. In the province, you know, we have a strong workforce. I refer back to some of the large projects that have been occurring here, and we are one of the few jurisdictions in the country and in North America, again who has had a steady stream of large projects and it goes from Hibernia, to Terra Nova, to White Rose, to Voisey's Bay, to the Vale Plant, and what we've seen is the development of a labour force that's skilled in large projects, we know they're available, we know that the workforce is skilled and has the ability to produce these projects. In addition, we've developed the expertise and the management resources throughout the province that are available to us at Nalcor to be able to move into this next project.

From a base business perspective, this is a large project that's going to take significant resources, but we've also laid the groundwork and the base business at Nalcor,

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and if you look at our operating businesses with certainly Newfoundland and Labrador Hydro, Churchill Falls Labrador Corporation, our oil business, we have in all cases over the past five years we put - you know, we've prepared our processes to be able to take on a project of this nature and be confident that the base operating businesses will still be effectively run over this period of time. We've put in an improved safety program, we've improved our safety performance by over 65 percent statistically over the past five years. We've improved our environmental performance KPIs, we've moved from an average of 75 percent of our annual targets to consistently over 95 percent of our annual targets. Our up time measures have stabilized with respect to our transmission up time, our generation plant up times. We've put in an asset management program, an in depth program which - and reorganized the company to be able to accommodate the significant - you know, essentially a rebuild of the base system that has occurred after 30 or 40 years. So we're confident that we've put the processes in

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place as well, and have the people in place to maintain a clear focus on the base operating business in addition to being able to execute this project. So that's really what I wanted to say from the perspective of this the right time, and I believe it is. We have the need, it is the low cost option, and for the other points I mentioned, additional points as to why the timing is good for this particular project. On the flip side of that, the obvious question is are there risks associated with this decision, and absolutely there are risks associated with this decision, there's no question about that. There's risk associated with any decision naturally. When I sit back and look at a couple of points with respect to that, if I look at Muskrat Falls Labrador-Island link, it's a large construction project, and I think the key risk that we focus on there is primarily a cost risk, you know, will be have the ability to control the cost expenditures and the schedule associated with Muskrat Falls and LIL.

On the flip side, if you look at the alternative, an isolated island option,

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there's also risk there. There's also cost risks with respect to construction required in that side of the coin, but in addition to that, there's fuel cost risk in terms of what's going to happen to the thermal cost of fuel over the next several decades. So when I look at that, I believe we have the ability, more of an ability to control the cost of construction under either option, and granted Muskrat Falls LIL has a higher up front capital, and the alternative isolated case we looked at, there's significant capital, but it is spread out further, but nonetheless, there is construction and a cost risk associated with both, but that's cost risk - that's risk we can get our arms around, we can work on, we can mitigate, and we can minimize. You can never get rid of all the risk, but we can certainly identify, work on it, and have some ability to control and mitigate that risk. If you look at the fuel cost risk, we essentially have no control over that particular risk. It's a globally driven commodity. Our demands certainly is nowhere anywhere near any place that we could impact that demand, and on the

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isolated island side of the coin, we are totally at the mercy of the global markets with respect to fuel costs in the long term. So from that perspective, I say, yes, there are risks attached, but, yes, we can manage them. So what we need to do is identify these risks early, we need to respect these risks, know they're there, and we need to work to mitigate each risk to the extent possible so we minimize that risk and give ourselves the opportunity, the highest opportunity, the highest probability to deliver a project like this on time and on schedule.

So that really concludes my opening comments. We have a need, we have a low cost option, there's a lot of benefits that I believe are driving us to the timing is right now. There's risks associated with this project, there's risk associated with the alternative. We believe that we have the processes in place to manage those, and what I'd like to do now is turn the discussion over to Gilbert and he's going to expand on some of those and take us through a more extensive process that you'll be able to point to some

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specifics in terms of what I've already discussed. Thank you.

MR. BENNETT:

Q. Good morning, Mr. Chairman, Commissioners. It's a pleasure to be here, and as Ed pointed out, I'm going to build on material that Ed has covered in his opening remarks. This presentation is basically going to follow an overview of the material in our submission. So the same structure and order in this presentation will basically mirror what we have in the submission that we have filed with the Board.

Before I get into the presentation, however, I'd just like to briefly look at Nalcor's corporate structure. We have five lines of business. I think the important point here is that we are a Crown corporation owned by the Province of Newfoundland and Labrador on behalf of the people of the province, and our single focus is building a strong economic future for successive generations of Newfoundlanders and Labradorians. The team that will be presenting over the course of this proceeding

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includes myself, as Vice-President Lower Churchill Project, and in addition to myself, we also have Mr. Paul Humphries, our Manager of Systems Planning for Hydro; Mr. Paul Harrington, Project Director for the Lower Churchill Project; and Mr. Steve Goudie, our Manager of Economic Analysis; Jason Kean, Deputy Project Manager for the Lower Churchill Project, and Mr. Paul Stratton, Senior Market Analyst for Newfoundland and Labrador Hydro. So we assembled our panel to bring these representatives into the proceeding to assist in addressing any questions that may be raised. The presentation outline, as I mentioned, basically covers the submission format. At the end, we do have some comments on the MHI Report that was filed. However, the ten items cover the load forecasting process, our assistant planning criteria and need identification, identification of options and how we screen those, the description of the isolated island alternative, the interconnected island alternative, and how those two alternatives were developed as an optimized set of generation options from the

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initial group of alternatives that were created in the screening process. I'll run through the cumulative present worth or CPW analysis, a brief description of Muskrat Falls and the Labrador island link which are important parts of the interconnected island alternative, a brief overview of our decision gate process which we're using for our project planning, and update on project execution, as I mentioned earlier, some brief comments on the MHI Report.

Load forecasting is the foundation of all of our generation planning and our generation expansion process, and certainly we look at the processes that are within Newfoundland and Labrador Hydro, those processes have been established for many years and the process of assessing supply and demand for electricity within the province, and then making recommendations to ensure the system can meet that demand. It's a fundamental process that's embedded within our system's planning group. We recognize that there are long lead times for developing new generation and the associated transmission infrastructure that

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goes with that, so it necessitates that we have a long term planning process. This process ultimately delivers a Generation Planning Issues Report. That report is issued on a regular basis and identifies future work that would be required to expand the system. In 2010, our load forecast indicated that new generation would be required by 2015 in order to meet the capacity deficit on the island interconnected system. Our next release of this report will either be with decision gate 3 in our planning process and/or with the 2013 capital budget process for Newfoundland and Labrador Hydro. Our forecasting model is a comprehensive one. It's an econometric demand model. It's built on a 20 year forecast period for island interconnected load, and that load includes Newfoundland Power and our hydro rural load. The main drivers in that forecast include an econometric forecast from the Provincial Government, a fuel price forecast, as well as our own hydro rate projections which, of course, have impacts on consumer demand and, therefore, feedback into the process. Our industrial load requirements

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are captured through direct contact with our industrial customers.

Beyond 2029, given that I mentioned we had a 20 year forecast period, our forecast is completed by trend with growth adjustments for the penetration in electric heat that will be expected at the time. So here's a view of the 20 year forecast that was the beginning of 2010, Decision Gate 2 decision making. There are couple of important points here. First of all, if we look back over our historical view here from a utility load perspective, while our population during the 90s declined by almost 12 percent, the electricity use continued to rise during this period. You see in the middle part of the last decade, in 2005 and later in that decade, we can see the impact of the two paper mill shutdowns and a decrease in industry in industrial load over that period, and that looking forward into the future, we see the impact of the Vale facility at Long Harbour coming on line. In the long term, notwithstanding the issues associated with the fishery and other economic impacts that have happened during the 90s, we see over

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that period a continued increase in utility load on the system.

Looking forward into the future, we see that expected penetration and use of electric heat for space heating will continue to increase as that's a preferable alternative to oil heating. One question that has come up throughout the course of this proceeding in many of our public consultations is the question of meeting industrial load in Labrador, and I think it's important to point out that we are in continued and ongoing contact with proponents and developers in Labrador. At this point in time, we have no firm commitments from additional development opportunities in Labrador. Initially we will have surplus energy from Muskrat Falls, as well as additional resources to meet the needs of industrial development both in Labrador and elsewhere in the province, and those would include island hydro resources, other developments in Labrador, wind, recall power that we currently export into the market, as well as imports from the broader North American market. So those are all available

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options in a portfolio that we can use to meet those needs.

Having identified a requirement to meet additional demand on the system; in other words, an increasing load forecast, now we turn to our system planning criteria and the identification of the needs that fall from that. So if we look at generation and transmission planning within Hydro, Hydro has an existing set of generation planning criteria and those are designed to meet both capacity and energy requirements on the system. The transmission planning criteria focus on the bulk transmission system, our terminal and substations, and they consider contingencies, back up requirements, as well as emergencies on the system, and those existing criteria are optimized with minimal adaptations for our isolated system. So in general terms, our transmission and generation planning criteria are generally aligned with those of the North American industry. However, we do note that we have had to make some adaptations to reflect the realities of our isolated system.

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Strategist is a software application that we use for decision support and decision making during this process. It's an application that's used by many utilities in North America to enable decision making with respect to planning. It performs our generation system reliability analysis, we use it to project costs and generation expansion analysis, and it is a tool that we use to produce the least cost generation expansion plans, as well as our cumulative present worth, or CPW. The CPW is an important parameter in this proceeding and this analysis that we're undertaking. It's the present value of all incremental utility capital and operating costs that would be incurred to reliably meet the specified load forecast, given a prescribed set of reliability criteria. So criteria established, our analysis would look at the two generation expansion plans that have been developed with and without the interconnection, and then we calculate and compare the cost of both alternatives, so we can identify which one is the lower cost alternative. There's a broad

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set of inputs that go into this model. It includes all of the key functions that we used in the business. So we have our planning load forecast, we have a forecast period, we have an assessment of the shape of the load on the system, our escalation parameters, forecasted fuel prices, cost of capital and our discount rate, capital cost estimates for the various projects and developments that are used in the planning horizon, the terms of our power purchase agreements, information with respect to service life, potential retirements of components of the system, operating maintenance costs, heat rates for our thermal facilities, the generation capacity and energy capability of each of those potential resources, asset maintenance schedules, as well as forced outage rates. So you can see here that there's a comprehensive set of inputs that go into the Strategist model and evaluation.

Having established a load forecast and now having a framework for doing the analysis, it's important now to look at the alternatives and our screening process to see which

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developments and which projects and which alternatives and opportunities can go into the analysis. So we've looked at a broad portfolio of supply options to meet future needs. They include indigenous resources here in the province, facilities that are driven by imported fuel, as well as potential for importing energy from outside the province. The key point, however, is that the proper planning of the province's electricity system has to be based on proven technologies that are used in the utility sector where risks are reasonable and the probability of success is high. So there's a clear expectation that alternatives and options that are being considered are viable, are reliable, and will continue to keep the lights on here in the province. So we've developed a set of alternatives and we've taken those alternatives and run them through an initial screening process, and that screening is intended to identify and make sure that we focus on options that have the highest potential to ensure effective expenditure of rate payer's money. With those initial

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screened options prepared, we then develop an optimized least cost generation expansion plan using Strategist for the supply options that have advanced through our initial screening. So the important point here is that we look at that broad set of initial options, screen them down to a set that is technically and economically feasible, and then develop an optimized expansion plan using those in Strategist.

There's some important screening principles that are applied on that broad set of options. First, security of supply, reliability, technical feasibility, is first and foremost a consideration for us. Cost to rate payers is important. Environmental considerations associated with some of those options, as well as the inherent risks and uncertainties, as well as the financial viability of some aspects of the expansion plan that would be non-regulated. So with that screening process undertaken, the alternatives now group into two broad categories. We have a set of options that are applicable in an isolated scenario where the

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electrical system on the island continues to operate in isolation of the North American grid, and in this case new generation capacity is limited to what can be developed on the island. So if we don't have an interconnection to the rest of North American, we can't import, we can't get energy from other locations because we don't have the interconnection, which leads us to the second broad set of alternatives which looks at it on an interconnected basis, and now we're able to use generation sources that are off the island. So generation resources in Labrador, for example, now are available to the Strategist analysis. So we're using generation sources that depend on at least one transmission interconnection to the system. So the results screen down to in the isolated island case, our thermal alternatives are simple cycle and combined cycle combustion turbines, wind is a resource that we can develop, as well as the island hydro-electric alternatives. In the interconnected case, we have that group of options as well as the Labrador hydro-electric resources which could

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be brought to the island using a transmission interconnection. So the Labrador resources and the transmission interconnection are added to the set that's available, the isolated alternative. So at this point we have a set of supply options, and we're going to use Strategist to optimize that set into a least cost expansion plan for an isolated case, and a least cost expansion plan for the interconnected case. In other words, we have the best isolated alternative, we have the best interconnected island alternative, and then we're going to compare the costs in those two optimized alternatives. I think it's important to point out here that each of those alternatives is assembled with a set of generation options. So the isolated island alternative is not simply one plan, it's the best plan of a combination of wind and hydro and thermal resources that we can put together to meet our reliability criteria, and if it's also the least cost of all the potential configurations that you could build with those generation options. The same is true for the interconnected island alternative, that it is

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the least cost scenario that can be put together with the generation options available in that plan.

I think it's important to reflect on conservation and demand management. This is a topic that has come up on many occasions and our view, first of all, with respect to conservation and demand management is that our electricity supply sources, all of them are important resources, they're valuable resources, and we all need to use those resources effectively. We need to conserve these valuable resources. That being said, however, our response to date for CDM programs and initiatives has been modest, and it has lagged targets that we have established both between us and Newfoundland Power. We'll continue to pursue conservation and energy efficiency measures, but because of the uncertainty of the outcomes with respect to conservation and demand management, we have not incorporated specific targets into our load forecast, and we have not considered as an alternative to new generation. However, we have completed sensitivity analyses within our

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financial analysis to study and to indicate the effect of conservation and demand management programs in our analysis. So with the process now where we have the load forecast, we have a set of alternatives, and we've completed an optimization, I'd like to take some time now and talk about the isolated alternative and look at the optimized set of generation expansion options that falls out of our analysis.

So at the outset, the alternative includes proven technologies and supply options that have passed our initial screening, and secondly, have been sufficiently engineered to ensure that they can meet reliability, environmental, and operational requirements. So we have to set that as the initial test before we can move any further. It's also important to note that this alternative is heavily dependent on thermal generation, and with those two points in mind, there is at the end a high level of certainty that the elements in this plan can be permitted, constructed, and integrated successfully with existing operations. So the

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optimized isolated alternative sees a combination of wind and hydro, as well as thermal generation being added to the system. In this scenario, one of the first things we would do is put another 25 megawatts of wind on the system, followed quickly by construction of the small hydro resources that we've identified in our submission, that being Island Pond, Portland Creek, and Brown Pond. It's important to note that we would also - consistent with direction that's been provided by Government of the energy plan, install and commission pollution control technology on the existing Holyrood facility. That would consist of electrostatic precipitators and scrubbers for sulphur emissions, as well as low NOx burners for nitrogen oxide emissions. Beyond this initial work in the next decade, we see the first combine cycle unit being installed on the system for 170 megawatts, simple cycle combustion turbines for capacity, two of those are added, and the wind PPAs that we have would be renewed in the latter part of the next decade, and then post 2030, we would see the replacement of the Holyrood facility

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and additional thermal generation being added to the system.

As Ed pointed out earlier, the most significant consideration in this isolated plan is the considerable expense associated with fuel. So if we look at the cumulative present worth of this expansion plan at just over 8.8 billion dollars, almost 70 percent of that CPW is going towards fuel, imported oil onto the system. So when we look at the risk in this plan, the risk here is fuel prices, the risk here is fuel price volatility, and there's also a risk associated with greenhouse gases that we have not included in our model, but all of those considerations associated with thermal generation are inherent in this plan. So when somebody says that there's a risk in the construction associated with Muskrat Falls and the link, there is also a significant risk in this alternative as well.

In terms of fuel forecasting, we obtain our fuel price forecast from PIRA. PIRA is an international company whose business it is to provide fuel forecasts. Their work and their products are widely used in the industry, both

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in the utility sector, as well as in other parts of the oil and gas industry. So we have a 20 year fuel price forecast from PIRA, and beyond that forecast period, we held the fuel price constant in real terms. So the escalation of fuel prices beyond our 20 year forecast period is simply escalated at the same rate we're escalating our CPI escalation through the remainder of the study term. I think it's important to look at the expected escalation during the forecast period from PIRA. So from 2010 to 2025, the compound annual growth rate ranges from 3.5 to 4. 5 percent, depending on the fuel source. So whether it's #6 or #2 fuel in the forecast, the escalation rate averages around 4 percent. So beyond our 20 year forecast period, we're actually escalating beyond that at about 2 percent. We've included forecasts from the National Energy Board and the Energy Information Administration from the US, based on a request for information, and those forecasts extend to 2035, and the numbers in those forecasts are consistent with the forecast that we're using in our analysis.

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MHI tested the fuel forecast to 1 percent below our escalation rate, and we didn't see a material change in the CPW.

Given the reliance on thermal generation, it's important to reflect on the Holyrood Thermal Generating Facility. Of course, this facility is 40 years old, it's an oil-fired facility without environmental controls. As I mentioned earlier, the energy plan contains commitments for electrostatic precipitators and scrubbers for sulphur dioxide, and particularly the emissions at that facility at a cost of almost 600 million dollars, and to address nitrogen oxide emissions, low NOx burners have been included in the expansion plan. So these measures with a total cost of approximately 600 million dollars will not address GHG emissions at that facility. So while we haven't included any cost for carbon and GHG emissions in our analysis, we would note that that is a risk. The other consideration with respect to Holyrood is that we have identified an added life extension costs for the period between 2016 and 2029 to the tune of approximately 230 million dollars.

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So at the end of our study, the Holyrood facility will be approximately 70 years old; however, we have taken it out to that period, I think, as a reasonable and conservative view of that facility. Someone could debate that. Another risk here is the possibility of the imposition of greenhouse gas regulation. Those are potential issues that we've not included in our analysis, and probably are best handled as a sensitivity analysis as we've done at the end of the analysis.

If we look at the interconnected island alternative, now we have an alternative that's basically founded on an interconnection to Labrador, and then the availability of generation resources from Labrador. I think we see we have a scenario that's now to a large extent driven by the Muskrat Falls facility. Muskrat Falls Hydro Facility at 124 megawatts, a 900 megawatt Labrador-Island transmission link to deliver that production to the island. The average annual production for Muskrat Falls is 4.9 terawatt hours, and Holyrood in this scenario would be displaced by approximately 2021, and generators at that

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point in time at the facility will operate as synchronous condensers, and they'll provide voltage support on the eastern Avalon Peninsula. As with the isolated island alternative, of course, we're using proven technologies and supply options, but this scenario is predominantly driven by renewable energy. It does include some elements of thermal generation post 2033, and that's driven by capacity shortfalls in the system, and not energy shortfalls. So in our analysis we identified short periods where we would need additional capacity of the system, but we did note that the renewable resources had sufficient capability to meet our firm energy demands. This is a situation where we have very small fuel exposure, but a requirement to have capacity for short periods of time on peak. This scenario practically eliminates our dependence on fuel and the volatility of fuel pricing for energy supply and removes the exposure to GHG emissions and carbon costs.

Now if we look at the expansion plan, this expansion plan is primarily driven by Muskrat Falls and the link which will be in

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service 2016/2017 time frame. So we see it coming in service here, Muskrat at 824, the link at the same time in 2017. We have a short term capacity shortfall just before 2015, and we would see adding a single simple cycle combustion turbine in order to get by that capacity shortfall. Holyrood will go into standby with the commissioning of the link and would be taken out of service as a generating facility approximately 2021. At the latter part of the study period, as I mentioned, we do have some capacity issues and post 2030, we will see the addition of additional hydro and thermal resources on the system in order to maintain that capacity margin. So the transmission facilities that are associated with this plan include the construction of the 900 megawatt HVDC transmission line from Labrador to the Island, the installation of a converter station at Soldiers Pond, avoids a construction of 230 Kv transmission across the province if the transmission line were to be shorter and located elsewhere. We see the conversion of the Holyrood generators to synchronous

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condensers, and as well in our analysis we find that we need to replace circuit breakers at a number of facilities on the island system. Those are included in our cost estimates as well.

The interconnected island CPW at 6652 is the basis for the 2.2 billion dollar difference in CPW from the isolated alternative, and in this case the dependence on fuel and fuel cost is fairly dramatically reduced and we replace that fuel cost with imported energy from Muskrat Falls. So I think an important point here is that the 17 percent fuel allocation is primarily between 2010 and 2016. Post in-service of Muskrat Falls and the link, the amount of fuel used on the system is a very small number, it's about .4 percent of the total CPW.

A. So with those two alternatives established, now it's important to compare the cumulative present worth of both alternatives to explore which one is ultimately the least cost alternative. So, aligning the CPW components of the two alternatives, the key point here is that we see the fossil fuel expenditure in the

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isolated plant, just over six billion dollars, and the interconnected plant, just over a billion. Of course, the Muskrat Falls power purchases have CPW of approximately 2.7 billion dollars and when we compare the sum of the two alternatives, there's a 2.158 billion dollar preference for the interconnected island alternative.

Some sensitivity analysis. I think it's important to explore the risks of the two expansion plants. So if you look at the scenario where, you know, we go to a high fuel price scenario, so PIRA's high fuel price forecast and CPW, the difference between the two alternatives is over five billion dollars. You can see the exposure in the isolated plant to fuel costs and we've updated this analysis for a new PIRA forecast in May 2011. So if we look at the reference case, 2.158 billion compared to a new forecast from the middle of 2011, the preference for the interconnected alternative is over 2.8 billion dollars. The effect of the Federal loan guarantee over the reference case is approximately 600 million dollars and if we include the cost of carbon,

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we can increase that CPW preference by approximately 500 million dollars.

Now, looking the other way, if we added -- if we can find that we can add additional wind to the island system, the CPW preference is reduced from 2.1 down to 1.7 billion and here we can see the impact of substantial CDM savings. So we did two analyses for conservation and demand management, one at 375 gigawatt hours in 2031 and one at 750 gigawatt hours in 2031 and they also reduced the CPW preference. If the Muskrat Falls and little capital expenditure were to go over our current estimate by 25 percent, the CPW preference would be reduced by approximately one billion dollars. A low load growth scenario would see it further reduced and the PIRA -- finally, the PIRA low fuel price forecast sets the CPWs of both alternatives to be very similar.

So, I guess a key point here is that we look at these situations, and some of these are fairly high probability events. We're confident with the Federal loan guarantee. We think at some point in time carbon pricing

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could become a reality. So, we look at sort of the scenarios in either direction. We need to be careful that we balance these and that there's -- you know, when you look through them, there are both positive opportunities and there are both negative opportunities, but in each case in these scenarios, we find that there is preference for the interconnected island alternative.

Now as we move forward through our decision process, we will have further clarity on many of these components and we'll be in a better position to address those risks as the project definition and as the financial and economic situation becomes clearer as we get closer to a project sanction decision.

At this point, I'd like to take some time to just briefly look over the Muskrat Falls Project. The facilities that are included in this alternative, primary facilities, include both the Muskrat Falls generation facility with a capacity of 824 megawatts, 4.9 terawatt hours per year; we have two dams at the site, one powerhouse between the two dam locations; a reservoir, 60 kilometres long. We see

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construction starting in 2012; in service late 2016. The cost of the Muskrat Falls facility also includes provision for two transmission lines back to Churchill Falls and the construction cost of all of that work in Labrador is 2.9 billion dollars.

The Labrador-Island transmission link is the means by which we move that energy from Labrador to the island. It's a nominal 900 megawatt capacity line. It extends from Muskrat Falls to Soldier's Pond, which is near Holyrood. It's approximately 1100 kilometres long and includes 30 kilometres underneath the Strait of Belle Isle. Construction is aligned with that for Muskrat Falls, so start up in 2012, in service late '16 and the construction cost of this facility is 2.1 billion dollars. So those are the basic elements that are the major part of the interconnected plan.

The planning process that we've undertaken is what we call a decision gate or gateway process and there are some important elements in that plan. First, we provide checks and balances throughout the process that decision makers require in order to

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demonstrate that we have an acceptable level of readiness at each stage in the process. So, as we move through this process, we can make two general observations. First of all, the magnitude of expenditures increases as we move through each gate. So preliminary expenditures, you know, for initial screening and additional identification of opportunities is in the order of a million dollars per year. As we move through phase two and phase three, we're moving through tens of millions of dollars per year to hundreds and ultimately in construction, we'll be spending billions. So the significance of decisions as we move forward increases.

So it's important that we have steps in this process where we have a rigorous review of the work that's been completed and also a rigorous review of our preparation to take on the next step of work and that's what happens: at each gate in this process, we stop and take stock of where we are, what we've done and what we need to be able to do in the next stage. So the gateway process provides us with a systematic control process for managing

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the evolution of the project, and at each decision gate, we have a series of steps in the decision making process. So we move from the project team through an independent project review to a group of the Nalcor leadership team, which sits as executive committee, reviews the reports that come forward and ultimately we make a recommendation to our CEO who takes that recommendation ultimately to Nalcor's board and Nalcor's shareholder. At that point in time, a decision has been made to clear a particular decision gate.

So this process will be repeated at key points throughout our planning process as ultimately we would -- we've made a decision at Decision Gate 2 to undertake our phase three engineering work and our phase three preparation. At Decision Gate 3, a decision will be made to sanction. At Decision Gate 4, a decision will be made to put the plan into service and start operations. So each of those processes has a rigorous set of evaluations and approvals before we get through the gate.

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So, the project readiness, we look at all of the work that needs to be done, includes several key areas. First, from a business prospective, we have a series of formal agreements, include financing, governance, acquisition of funding and a cumulative present worth analysis or system planning and integration considerations, as well as our facility operations considerations.

From a project execution and construction perspective, have to look at project management controls, technical engineering and design work, construction execution, contracting and procurement work, health safety and environmental plans and considerations, as well as our operations and maintenance strategy.

And then finally, there are external factors that include regulatory, environmental and other authorizations, as well as our aboriginal and reviews that are undertaken as part of the process. So some of these processes are within our own control and we would prepare for those and others are external factors that we ultimately have to

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have clearance and approval before we can through.

Some of the major activities that are leading to Decision Gate 3 include our continued engineering efforts to increase the project definition and to obtain a class three capital cost estimate. The procurement and contracting of long lead items is important to us in order to maintain a project schedule, but it's also important to set aside risk. So, if we look at some of the major components in the capital cost estimate, for example, turbine generator sets and submarine cables, it's important for us to have certainty on those so we would start the procurement process in order to have accurate pricing to include in our new capital cost estimate.

Aboriginal consultation and the agreements that flow from that. So that consultation is an essential consideration in our project planning and it's an important factor in the environmental assessment as well that the environmental release is dependent on clearing and making sure that aboriginal consultation has been undertaken effectively.

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Commercial financing terms, system integration planning and the operations reliability, regulatory compliance are all steps that are currently under way that would lead us to preparation for Decision Gate 3.

Take some time to talk about project execution for a second. We come into this project from an execution perspective with an experienced team. The team that we've assembled includes both substantial operations experience within our Nalcor team, as well from a construction perspective, significant Canadian and international project execution experience. So we've assembled both of those competencies within our team and we now have over a hundred people working on project execution for the Lower Churchill. That internal capacity and capability is supplemented by an experienced international engineering, procurement and construction management contractor, that being SNC Lavalin. So between our own core competencies, capabilities that we've brought into the team from a construction perspective, as well as the assistance, advice and expertise that

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comes in from SNC Lavalin, I think we're well able to take on the project.

A fundamental part of our approach is that we're using proven practices here. Project execution approaches and practices, an important one being the notion of front end loading, is improving our cost and schedule predictability in our project planning and the independent reviews that have been undertaken by IPA, IPR, Navigant, as well as by MHI, confirm the use of best practices in our project planning approach. Some important success factors we look at from a project execution perspective include having a clear scope definition of the project, having a solid project execution plan, a realistic cost estimate basis, a straightforward optimal contracting strategy, use of proven technology, as well as a strong owner team that's applying controls to the execution of the project.

We look at our project planning, it's important that we undertake the work early in the project evolution to set the game or set the stage for project success; that the focus

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in the early stages of the project is on having an optimum strategy and an optimum project definition. Once we've defined the project and have started construction, we are going to build what we started out with the plan. So the value in project planning is in the early stages where we have the ability to influence and set the stage for project success. Once we've sanctioned, we're going to build what we had planned to build at that point and if that planning is ineffective, we're not going to have a satisfactory outcome.

So we are putting a significant amount of effort in our early project planning and the process is called front end loading. You have an opportunity to increase the definition of the project, to do field investigations and studies and engineering studies in order to increase the level of definition, you should do it early, so you don't have surprises when you're actually building what you're setting out to do and it's one of the key reasons why our expenditures in the early stages of the project are significant, but when we look at

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the total value that's being spent early in the project, that amount, that percentage, is consistent with what we see on other mega projects. Some well executed mega projects have substantial expenditures upfront to make sure the project is well defined and there's a good strategy in place for construction.

The capital cost on Muskrat Falls first is driven by favourable construction characteristics at the site. So we look at the physical characteristics of Muskrat Falls, the geotechnical conditions are favourable. We're on competent bedrock. We have minimal overburden to move out of the way and those conditions have been validated by a comprehensive set of site investigations on site. So we expect limited exposure with respect to quantity growth on the site. The site is constructible. The construction materials are primarily sourced from excavations on site. There's a good material balance. We have minimal excess material and spoils at the site, and we're using mostly conventional concreting methods and equipment in dry conditions.

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So other sites, you know, may not have the same characteristics. Certainly, if you look at some other hydro projects, Karahnjukar in Iceland comes to mind, which was a facility that has an extensive system of tunnels to get the water into the powerhouse. So the complexity and risk associated with that construction are different than what we see at Muskrat Falls. We're in a good situation in Muskrat Falls having access to the construction site from the Trans Labrador Highway on the south side of the river and that is actually a major improvement to the site that happened since early work was done on the site back in the late '90s where the project required three diversion tunnels in order to keep the water out of the powerhouse development area. So, when we look at the site specifics of Muskrat Falls, it's a very favourable site to develop.

Look at the physical layout. We have a relatively compact location. We don't have an extensive series of dikes and dams like you see at Churchill Falls, for example. The site is contained within a relatively small area.

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The flow on the Churchill River is reliable and predictable. We have a long record of hydrology for the site. We have a long operating history for Churchill Falls. We have the regulation from the Churchill Falls reservoir upstream on the facility. Power structures are located on one main site, robust and conventional designs for most of the components. As I mentioned earlier, there's no underground works on the site. So, when we look at the characteristics of the site, they're generally favourable.

From a project execution perspective, it's great to have a good site, but now we need to make sure that we have an approach that eliminates risks along the way as well. So technology decisions become important. We look at the elimination of VSC technology at this point in time in our basis of design that we're using robust, conventional line commutated converter, HVDC technology. We have included a spare cable on the Strait of Belle Isle, recognizing that that is a risk to be considered carefully. We've brought in SNC Lavalin as our EPCM contractor. Geotechnical

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baseline, the impacts and benefits agreement with Innu Nation have eliminated risks in the program as well. Our preliminary work in our pilot programs on the Strait of Belle Isle, undertaking horizontal direction drilling on the site have de-risked that because we now have, you know, hands-on familiarity with the conditions on the site, both the rock conditions as well as the subsea conditions in the Strait. Our turbine efficiency program and the preliminary turbine model RFV that's been undertaken is done early so that we understand the characteristics of the generating units at the facility.

So going forward we'll be using similar approaches to make sure that we can identify and mitigate some of the major risks that fall out in execution. So, again, it'll be, you know, early work for major RFPs. So contracting strategies that optimize competition and synergies in the work skill. Early award of bulk excavation contracts so we can maintain the schedule, these are all factors, approaches that we're using in order to mitigate risk associated with the

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construction of the Project.
CHAIRMAN:
Q. Can I just stop you there, Mr. Bennett? I think we need to take a break. Is that correct?
MS. BLUNDON:
Q. Yes.
CHAIRMAN:
Q. You're looking at me, so -
MS. BLUNDON:
Q. Yes.
CHAIRMAN:
Q. I'm listening to you. She's the real boss here, you know. So we'll take what? What do you -- how long would you like? Ten minutes?
MS. BLUNDON:
Q. Ten minutes.
CHAIRMAN:
Q. Ten minutes or so.
MS. BLUNDON:
Q. Ten minutes or so.
CHAIRMAN:
Q. Is that acceptable to everybody?
MR. BENNETT:
Q. Absolutely, great.

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CHAIRMAN:
Q. Okay.
(BREAK)
CHAIRMAN:
Q. I guess we're back to Mr. Bennett.
MR. BENNETT:
A. Thank you, Mr. Chair. So the question of strategic de-risk, this is a fundamental part of our project planning. The effort to identify areas where, you know, we can mitigate risks has taken up a considerable amount of thinking on the project team. So, you'll see here that there are a variety of strategies and approaches that we're using to lay down and to mitigate risks that have been identified in our project planning. So, it's a point I think I need to reenforce that we have a good site, but we also need to have good practice and good strategy to minimize our project risk.
Another important consideration is using proven technology, that we don't want to have serial number one or first-of applications of new technologies in our project execution. That, you know, at the end of the day we've

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looked at all of the components of the project and all of them have analogs and approaches and techniques and technologies that have been used elsewhere in the industry.
So if we look at the Muskrat Falls site, it is a generally conventional site. We're not stretching the limits of the state of the art, you know, across this project. It's a low head facility. It's a close coupled powerhouse, founded on rock. The Kapline turbines are well within their flow and head range that we see used on a global basis. The design philosophies are based on four decades of hydroelectric transmission engineering construction and operations. We have conservative efficiency targets for the equipment and that's supported by equipment redundancy and the operation of the facility, that's a core competency and a core capability of the Nalcor team.
On the transmission side, the conventional HVDC technology has been used in Canada for 40 years. The mass impregnated submarine cables have a demonstrated long term operating life and they've been used

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extensively in Europe and elsewhere. The cable protection methods that we're using for the Strait of Belle Isle crossing are proven and have been used in other applications here in the province, primarily in the east coast offshore. The overhead HVDC transmission line is a typical and commonly used arrangement. The horizontal directional drilling technology that we've selected for the Strait of Belle Isle crossing is well within the boundary of the state of the art, both for size of the bore hole, as well as the distance that we're drilling. We're using conventional AC technology and it's an extension of the existing Labrador transmission system.
So, it's important that we don't introduce two risks into the project planning by finding ways to bring in new technology unless we can clearly demonstrate that we've mitigated those risks and that the introduction adds value to the project. So, you may have seen in some of the material, for example, that the volt of source converter was excluded at this point in time because at this point in time, we don't see an advantage to

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bring that in and we don't need to introduce that risk. So, in all aspects of our planning, conventional, proven approaches, a fundamental part of our project philosophy.

The Strait of Belle Isle crossing is one that over the years, I guess, has taken -- has captured a lot of people's interest. We look at, you know, the northern portion of the island, the sea crossing there, the Labrador current, the extensive icebergs that come down the coast of Labrador through Iceberg Alley, I guess, is one area where people have looked at it and said "well, this is a significant risk" and I thought it would be helpful just to take some time and explore that crossing because it has, I guess, a number of unique features, but the crossing itself builds on our team's extensive experience in design and installation of subsea infrastructure in harsh environments and we've learned from other projects that have been completed globally.

So the team that's involved in this crossing has experience directly in the Newfoundland offshore. So, the techniques that are used on the Grand Banks for

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protecting subsea structures we've applied to our project planning. So, each of the three submarine cables on the crossing will have their own dedicated horizontally directionally drilled or HDD conduit that protects the cable on the shore. So, the shore approaches, we have the potential to experience pack ice. Pack ice pushing up against the shore would have the potential to damage a cable on the seabed. So our approach here is to use this drilling technology to get the cable out in deep water, so we avoid that failure approach.

The conduit that's drilled from the shoreline takes the cable out to a depth of between 60 and 80 metres and therefore we avoid the potential for iceberg scour and damage to the cable. So once the cable is out on the seabed under 60 to 80 metres of water, the cable is laid on the seabed and then each of the cables will be protected with its own rock berm which will protect against fishing gear and dropped objects on the seabed.

So these approaches are new for Nalcor, but are certainly commonly deployed on the Grand Banks. They're used by the offshore

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operators on the Grand Banks and the people that have designed and constructed those facilities on the Grand Banks are part of our team. So we're bringing that learning and that capability in to mitigate that risk.

We look at the Strait of Belle Isle itself, there's some important features associated with that part of the island and the province that afford protection to the cable as well. So northeast of our Strait of Belle Isle crossing, there's an area of shallow water. The water depth is about 60 metres. So if a large iceberg crosses that area, it will ground on that shallow water and it'll stay there until it either melts or breaks up. So by getting our cable into water depth that's below the depth of that shield, we'll protect the cable on the seabed and really the only failure mechanism that we're worried about at that point in time would be fishing gear and fishing activity that may damage the cable in deeper water. But the whole question of iceberg risk and the question of damage to the cable has been valuated. It's been analyzed and considered

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and mitigated so that we can remove that issue as a major risk factor for the project.

Procedurally, I guess, in terms of developing the DG2 cost estimate summary and the cost estimate that we have, I think it's helpful to look at the process that we used to develop that cost estimate. First of all, it was a detailed bottom of cost estimate. So in earlier work, we had taken previous estimates and scaled them up. This wasn't the case here. This estimate was built from the bottom up, line item by line item. Of course, that capital cost estimate report was issued at DG2 and that's been available to the Board and to the Board's consultant as a confidential exhibit and that report documents our assumptions, our pricing considerations, the risks associated with the capital cost estimate, as well as a contingency that's been developed. In places that -- and for key items, that estimate also included quotes from suppliers and equipment manufacturers. So we were able to supplement the knowledge and insight that the team had in developing that estimate along with specific information from

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our vendors in the form of budgetary quotations for major pieces of equipment in the project.

The estimate has been validated by independent expert external consultants who have been retained specifically to review the capital cost estimate. The escalation factors that are used in the estimate have been validated by external consultants as well and the whole effort of our detailed engineering activities that are being undertaken now is to take those base estimates, the escalation and contingency factors and then update them for DG3. So that we'll take all that work, undertake detailed engineering, update the quantities, materials and so on, and then build a new estimate for our Decision Gate 3.

So, the whole objective, the objective of this process is to continue to improve the accuracy of the capital cost estimate by completing our detailed engineering design and improving our level of project definition. So on this graph, we have our project at-cost estimate accuracy on the vertical axis and our investment in time and effort on the

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horizontal axis. So as we continue through our process, at Decision Gate 1, we would have had a class five estimate. At Decision Gate 2, we have a class four estimate that has a greater level of definition, that has improved cost estimates in the form of quotations and a more detailed capital cost estimate and therefore, we reduce the level of -- we improve, rather, the level of accuracy in that estimate. Decision Gate 3, we'll have more further engineering work done, quantities will be better defined. The execution strategy will be better defined and we can continue to reduce the level of error inherent in the capital cost estimate as we move through each decision gate. Ultimately, the objective is to predict the final cost of project closeout.

I won't go through all the detail on this slide because there are many factors here, but the point that I wanted to make was that there is a lot of information, a lot of material, a lot of analysis that goes into the work steps and the work process that takes us from the initial input, the scope of the capital cost estimate, all the way over to a base estimate

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at Decision Gate 3. So there are four key factors and a long list of individual components that go into those factors that are used to develop the DG3 capital cost estimate. So we have to define the scope of the project, the scope of the work. We have to identify and define the construction methodology and the schedule or time line factors associated with constructing the facility. Our price factors include the cost inputs into the analysis as well as then performance factors, where we start looking at productivity on site. So we have to have a complete view of those four categories of factors in order to ultimately determine what our base estimate will look like. So we've been undertaking this work as part of our phase three effort. There is a lot of analysis, a lot of detail, a lot of effort that has to be expended before we can create that new capital cost estimate.

And I should point out, before I step beyond that, that once we have the base estimate, then there is a series of work that has to be taken to evaluate the risks and contingencies associated with that base

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estimate. So the base estimate is actually an intermediate step in completing the final capital cost estimate with the contingency, with the escalation, with the probabilistic risk analysis assessing the accuracy of that estimate once the base estimate has been created.

The final topic that I'd like to talk about this morning is the MHI report and I think at the outset, you know, it's important for us to say that, you know, we respect and value MHI's assessment and expertise in this process. From a perspective of a project planner, having additional input, having an opportunity to have an evaluation of the work that we've undertaken is extremely valuable to us and we look at this in the same light as the external and third party reviews that we've done as part of our own internal planning process. Getting feedback from somebody who knows the business is very valuable and helpful for us because it always improves our project planning and our approach and we value that input and we actively seek issues and risks that we need to consider.

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We're not interested in spending a whole lot of time looking at what went well. We are really looking for opportunities for improvement and that's a fundamental part of our process as well.

But in summary, though, we're pleased that MHI concludes that Nalcor's analysis was reasonable, was appropriate and was performed largely in accordance with industry best practices. But that was our objective at the outset and we're glad to have validation that, in general, that those objectives were achieved.

There were some areas that were identified by MHI. I'll just take a few moments this morning and just review where we are with those. Those four items were the matter of transmission line design criteria, system reliability, AC integration and the application of NERC standards.

So with respect to transmission line design and the criteria that go into that, of course our objective at the outset is to ensure that the reliability of the Interconnected Island System remains, at a

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minimum, consistent with our historical experience and a fundamental principle is that we will not advance an alternative that does not meet an acceptable level of reliability. We complied with the CSA standard respecting design criteria of overhead transmission line and I think in terms of our approach to this, the Labrador-Island link was designed to a one in 50 year return period and that reliability is consistent with the current island system, and the reliability of that line was tested for compliance against our current generation and transmission planning criteria.

We've looked at increase in the return period of the Labrador-Island link. Certainly we could increase it beyond a target of 50 years to one in 150 years and beyond and that certainly does reduce the probability of a failure of that transmission line. But our observation here is that in the event that that failure occurs, the same number of customers will have unserved demand when it happens. So in addition to considering the impact of increasing the return period, an important part of our thinking was to look at

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the impact of the outage when it takes place. So the probability of the event is one consideration and it's a very important consideration. But the second important consideration, in our view, is looking at ways to reduce the impact of the outage. We think in this case that reducing the impact would have a greater customer benefit than reducing the probability of the outage in the first place.

So, if you look at, you know, a situation where enhancements to the transmission line were deemed to be necessary or enhancements rather to the Island Interconnected System were deemed to be necessary, we think that a better cost benefit option for ratepayers is the addition of standby generation on the island. This has a greater customer benefit than increasing the return period on the transmission line. We also note that the reliability of the system will improve with the construction of the new 230 kV line between Bay D'Espoir and Western Avalon and that line is required in both alternatives.

And another important point for us is

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that the addition of the Maritime link to the system further enhances the system reliability, that with the availability of import capability from the Maritime Provinces, we reduce our dependency on the transmission link from Labrador. So the Island system has the ability to obtain power from the Maritimes in the event of a structural failure. So our approach here is to minimize and reduce the impact of the failure by making additional supply available.

From a reliability perspective, our transmission planning criteria are evaluated based on a deterministic approach to modelling. Now our generation planning is evaluated based on a probabilistic model. So I guess to look at that in some more detail, everyone of our generation alternatives has a forced outage rate associated with it. There is a probability that it will not be available for service because of some unplanned event when it's called to. So we have to deal with that contingency. In terms of our planning here, we looked at the Labrador-Island link as being part of that generation analysis because

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it enables the delivery of Muskrat Falls power. The primary purpose of that link is to make Muskrat Falls energy and power available to the Island system from the generation source at Muskrat Falls. So we incorporate the availability of the Labrador-Island link in our probabilistic analysis for generation supply and in that analysis, we assume that the forced outage rate for the link would be 0.89 percent per pole. We're of the view that that was an appropriate number and I think MHI concluded that this was a number that was within the range of what they had seen and what they've used themselves, but building on that, beyond DG2, we are implementing a more advanced model and a more comprehensive reliability model that would incorporate all components of that link and that work will be done in contemplation of Decision Gate 3.

So this is an ongoing process. It's exactly the same process that we're using for our project construction. As we move forward with greater levels of project definition, we continue to tighten down the criteria and the modelling approaches that we're using in our

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planning.

And that probabilistic model will incorporate our transmission line design criteria, the continuous overload capability that we have in the Labrador-Island transmission link design, the installation of the spare cable in the Strait of Belle Isle crossing, as well as the availability of spare converter transformers and spare smoothing reactors at each converter station. So we are looking at the components that have significant probability for an extended outage and making sure that the spare parts are available to deal with that outage. Those factors will all be incorporated in our probabilistic model.

In so far as AC integration studies are concerned, we would agree that it's important that the system be modelled both in Labrador and on the island so that we're confident that the new DC link can be effectively integrated into the AC systems and for Decision Gate 2, we analyzed Teshmont's 1998 Integration Study. That report is filed as Exhibit CE-31 and that integration study evaluates an 800 megawatt

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point-to-point HVDC link from Gull Island to Soldier's Pond.

The Maritime connection is not included in that study, but that work was added as a later study and we built on the 1998 work with a 2007 study that did study Gull Island and a 1600 megawatt three-terminal HVDC system that included terminations at Gull Island, Soldier's Pond and New Brunswick. The analysis indicated or determined that the point-to-point link will have similar characteristics regardless of the change in generation source from Gull Island to Muskrat Falls provided we have transmission capability between the new generating site and the existing Churchill Falls facility, and as a result, Nalcor did have sufficient input data to move through Decision Gate 2 on the understanding and with the intention that the full integration studies for the HVDC system would be completed at Decision Gate 3.

NERC or the North American Electricity Reliability Corporation establishes reliability standards for the majority of electric utilities in North America and

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certainly it is a reliability organization or ERO that was certified by FERC, the Federal Energy Regulatory Commission out of the United States, to establish and enforce reliability standards for the US bulk power system and NERC has developed and enforces reliability standards under the definition of good utility practice. In many Canadian jurisdictions, government policy, government legislation and regulation have provided for reliability oversight by utilities boards in those provinces using the NERC reliability criteria. So that's the use of the regulatory legislative framework. It establishes a role for NERC in those utilities.

To date, that hasn't taken place here in the Province, but from our perspective, you know, we look at the situation in -- I guess in looking ahead of that expected regulatory oversight, we have established and instituted a system integration team to investigate the technical system operations reliability regulatory implications for the integration of Muskrat Falls, the link and the Maritime link into the North American system. We do know

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that our neighbours, both in Quebec, as well as in Nova Scotia, have regulatory oversight, have provisions for reliability standards and criteria within their respective systems and that both NERC and NPCC, the Northeast Power Coordinating Council, have a role in reliability standards in those neighbouring systems and it will be important for us to ensure that our planning and our operations don't affect the operations of those neighbouring systems and don't compromise the bulk grid in eastern North America.

So, we're engaging with those jurisdictions. We're also engaging with NPCC to understand how we fit into that regulatory framework and our objective here is to balance the requirements of those neighbouring systems with ratepayer interests here in Newfoundland and Labrador. So, as regulatory oversight, for reliability advances within our province, and understand that's a commitment of the Energy Plan as well, that that oversight will be evaluated and brought forward. We'll be participating in that process, but the most important question for us at this point in

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time is to absolutely assure that our interconnections with our neighbours don't result in a reliability problem or concern in those jurisdictions while at the same time making sure that our system here operates reliably and operates at a level of performance that we have used and has been implemented over the past number of years here in Newfoundland and Labrador.

Those are the key points that I wanted to address this morning in the presentation. So just to very briefly summarize.

Our analysis has indicated and concluded that new generation is required to meet load growth here on the Island system and that Muskrat Falls, the Labrador-Island transmission link, is our least cost solution. It's the most economic least cost option. It takes the Holyrood thermal plant off line and avoids the replacement of that facility with further thermal generation. It enhances our system reliability and security of supply by enabling interconnections both to Labrador, as well as to the Maritime Provinces, and in the long term provides rate stability for our

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customers and rates that ultimately will be lower than we would see in an isolated alternative.

I think that's my last slide. Thank you.

Thank you, Mr. Chair.

CHAIRMAN:

Q. Who's next, Madame? Mr. Johnson or does Mr. O'Reilly have some -

O'REILLY, Q.C.:

Q. Mr. Chairman, what we propose to do now, the second part of the -- that's the -

CHAIRMAN:

Q. Oh, okay, I'm sorry.

O'REILLY, Q.C.:

Q. The formal part of the presentation is concluded. What we're going to do now is we're going to add the panel, a five-person panel -

CHAIRMAN:

Q. Oh, okay.

O'REILLY, Q.C.:

Q. - which will include Mr. Bennett, but not Mr. Martin, and they'll come in and take their places here and then they're available to be - - to answer questions from the Consumer

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Advocate and counsel for the Public Utilities Board. So we'll need probably two or three minutes just for them to move in and then we're ready to go. And I also have some -- I have filed, given to counsel, some CV information about the panelists, so those would be available to the Commissioners as they go through, just for their information so they'll know sort of the areas of expertise and what they can expect. The areas of questioning, I assume, will come out of that. So, if we can have another few minutes, we're ready to roll.

CHAIRMAN:

Q. All right.

(BREAK)

CHAIRMAN:

Q. Sir.

O'REILLY, Q.C.:

Q. Mr. Chairman, thank you. Mr. Commissioners, we had gone through the logistical exercise of organizing the panel here and I'd like to introduce them to you. We've taken the liberty of filing a brief file on each of them, but starting at the table closest to me

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at my left is--and moving towards the Commission bench, Mr. Steve Goudie who is the manager of economic analysis investment valuation with Nalcor Energy and next to Mr. Goudie is Mr. Paul Humphries, P.Eng, who is the manger of systems planning, project execution and technical services, Newfoundland and Labrador Hydro. Mr. Bennett, you've met and next to Mr. Bennett's left is Mr. Jason Kean, P.Eng, MBA, who is the deputy project manager for the local, the Lower Churchill Project, Nalcor Energy; and last, Mr. Paul Harrington who is the project director of the Lower Churchill Project for Nalcor Energy. And not to be outdone, we have one more in reserve and sitting to my left is Mr. Paul Stratton who is the senior market analyst with the project execution and technical services with Newfoundland and Labrador Hydro. He's sitting here because we don't think we're going to get very--a volume of questions for him, but if so, we'll have to do a quick changeover and put him over there. So subject to that, Commissioners and Mr. Chairman, the panel is available to entertain any questions

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from the Consumer Advocate and counsel for the Board.

CHAIRMAN:

Q. Okay, it's Mr. Johnson, to you, is it?

MR. JOHNSON:

Q. Yes, it is. Thank you, Mr. Chairman, Commissioners, gentlemen. I should start today by introducing our advisors from the engineering consulting firm, Knight Piesold, who've assisted the Consumer Advocate in relation to this reference. Seated to my immediate right is Mr. Mike Robertson and to his right, Mr. Boris Fichot who is part of the people at that firm who have been advising us and they are joining us from the Vancouver offices, so they got used to some of the rain down here, as opposed to home for a bit. Mr. Chairman, just by way of brief introduction, as you've noted this review or reference is aimed at determining whether the proposed Muskrat Falls generation station and Labrador-Island link HVDC projects are the least cost option for the supply of power and energy to the island of Newfoundland, as compared to the isolated island option over the study period

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of 2011 to 2067. And as anybody, I think, who has joined in with the webcast thus far, would now be acquainted with, there are certainly technical issues involved in answering that reference question. There's concepts of cumulative present worth or CPW, there's load forecasting, hydrology, reliability studies, thermal generation, oil price forecasts, base cost estimates, contingencies, escalation allowances, then there's sensitivity testing and many of these topics, of course, were addressed in Nalcor's submission and in the Board's independent consultant's report, Manitoba Hydro International's recent report. And I suppose an observation at the outset is that you couldn't blame a customer for perhaps finding the concepts a bit mystifying, but we should assure them that these are indeed issues that relate to the Board's determination of what is the least cost option as set out in the reference. So hopefully my questions will try to shed some light on the project and why it is being put forward as the least cost option.

I guess I would start, gentlemen, with

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November of 2010, that was when Nalcor passed through decision gate 2 and recommended to its shareholder, being the Government of the Province of Newfoundland and Labrador, that indeed it would be the Muskrat Falls option that would be pursued over the Isolated option and as we've been told this morning and as outlined in the documentation, as of that point, Nalcor's best assessment was that based on the work they had done, this was showing a cumulative present worth preference over 2.2 billion dollars or approximately 2.2 billion dollars over the Isolated Island Alternative that was studied, so we're correct so far. And for the people in the room, for people who might be joining us, how did you, in general terms, come to put a 2.2 billion dollar advantage on the option at the time you recommended to government that this was the one?

MR. HUMPHRIES:

Q. Thank you, I'll address that question.

O'REILLY, Q.C.:

Q. Might be helpful if Mr. Humphries could identify himself for the purpose of the

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record, would that be helpful?

MR. HUMPHRIES:

Q. Okay, I'm Paul Humphries, manager of system planning and ultimately the decision on the requirement to move forward and the determination of the best alternative and the determination of the cumulative present worth between those alternatives is the responsibility of my department in system planning and based on the inputs to that analysis, coming out of the cost estimates and work as described by Mr. Bennett in the presentation this morning, we took those inputs, put them through the strategist analysis program and came up with the cumulative present worth difference stating that the Island Interconnective Alternative would be the preference by 2.2 billion.

MR. JOHNSON:

Q. And as between the two options compared, you--Nalcor made the determination that Muskrat was to be pursued, and how did you ensure that as between the two options you were comparing that you were dealing with the optimal, I think as your presentation put it, the optimal

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scenario under each one?

MR. HUMPHRIES:

A. Okay, as explained in the presentation this morning, within each of those, the Basic Interconnected Alternative and the Isolated Island, we had a number of scenarios and generation sources that fit into those, that were fed into the input and the strategist program then did an optimization to ensure that within each of these alternatives that the least cost scenario was developed for the Isolated Island, as well as the Interconnected case.

MR. JOHNSON:

Q. And this strategist program that is mentioned in the materials and which you referred to in your answer, Mr. Humphries, what is that?

MR. HUMPHRIES:

A. Well it's an industry accepted piece of software used to determine this exact question, to evaluate generation expansion alternatives on a probabilistic basis.

MR. JOHNSON:

Q. And just on the point for a moment, when Mr. Bennett was going through the presentation

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this morning, he referred to a sensitivity test where he said well, what would happen if we put on more wind, for instance, in the Isolated Option and would I understand by having that added to a sensitivity that that extra wind had been screened out, I take it, and wasn't found to be optimal through strategists in your analysis?

MR. HUMPHRIES:

A. Well in the particular case of wind, yes, it was screened out, but the initial screening was based on a technical--there are technical issues with wind as well in the Isolated Island Alternative, given the fact that we are isolated from the North American grid and the ultimate amount of wind that we could integrate into the system is limited. So that was also a factor that came into that evaluation.

MR. JOHNSON:

Q. And why would it be limited, given our configuration?

MR. HUMPHRIES:

A. Well the fact that we are isolated and the fact that wind generation is variable in

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nature, it only operates when the wind is blowing and the fact that when we look at our system, and our load is quite variable, it can be quite high on a cold winter day, but you know, a warm summer night, it is quite low, and so to be able to economically integrate the wind into the system, we do run the risk of, at times of the year, actually spilling water to take the wind or we would have to curtail the wind.

MR. JOHNSON:

Q. And what would be the issue for a customer out there about spilling the water?

MR. HUMPHRIES:

A. Well once the water is spilled, that's money gone over the dam and it will eventually correlate into additional oil production at Holyrood.

MR. JOHNSON:

Q. Okay. Now the 2.2 billion dollar preference that had--or approximately 2.2 billion dollar preference that you had landed on in November of 2010, that seems obviously like a fairly large figure and that's in 2010 dollars, I take it?

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MR. HUMPHRIES:
A. That's a cumulative present worth to 2010, yes.
MR. JOHNSON:
Q. Okay, but at that stage it wasn't sufficient to say well now let's proceed to sanction the project and why would that be? There just wasn't enough work done at that stage?
MR. HUMPHRIES:
A. Yes, I think that was evident from Mr. Bennett's presentation this morning.
MR. JOHNSON:
Q. So, tell me then when the decision is made in November of 2010 to tell the government that Muskrat Falls is the option over this Isolated option and you passed through decision gate 2, okay, what did that mean on the ground, as it were, over at Nalcor once that gate had been closed?
MR. HUMPHRIES:
A. Well, from the project perspective it meant that there was a lot of additional work that we had to do to close the loop. From my perspective in system planning, it didn't mean anything. I still had to continue to plan the

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system and it looked like that the Muskrat Falls alternative was the way we were going, but I wasn't confident yet, we had to do further work to ensure.
MR. JOHNSON:
Q. Okay, and the new gateway phase, this phase 3, this is as I understand it, the phase 3 engineering and procurement and contracting phase, that's the phase that--that would be descriptor. And when officially did that phase start?
MR. HUMPHRIES:
A. I think I would refer that question to Mr. Harrington.
MR. HARRINGTON:
A. This is Paul Harrington, I'll take that question. The engineering, as you said the phase 3 or the engineering and procurement contracting phase which takes us up to gate 3, decision gate 3, that commenced shortly after the decision gate 2 decision was made. Certain number of things triggered into action at that point in time. One of them was the fact that we needed to engage an engineering procurement and construction management

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contractor, so we did that, we went out and--went out with a Request for Proposal, we obtained bids in from various engineering contractors, we went through the process of evaluation and we landed on SNC Lavalin as being the group that would--that actually won that contract and we could start then to negotiate with SNC Lavalin for a final contract. That took the period between November and February of--November of 2011 to February--sorry, '10, to February of 2011. So then we were in a position, we signed the contract with SNC Lavalin and then we started to mobilize the resources and put an office in place. The office is, in fact, on Torbay Road. So that was one of the big steps that we took, we brought on that additional help because, you know, we got a good team in place, but we needed the additional horsepower that SNC Lavalin could provide to us on the engineering procurement construction management aspects. They then started the work.
MR. JOHNSON:
Q. And was there a ramping up of SNC Lavalin over

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a period of time?
MR. HARRINGTON:
A. That is correct.
MR. JOHNSON:
Q. Okay. And as we sit here, how many people in house are engaged in phase 3 activities, how many people are engaged at SNC?
MR. HARRINGTON:
A. I might have to consult with my colleague for an exact number.
MR. KEAN:
A. Yes, this is Jason Kean, I'm the deputy project manager for Muskrat Falls and the Labrador-Island Transmission Link. To answer your question, SNC Lavalin has approximately 220 persons in the office here on Torbay Road, further, Nalcor has approximately 130 persons. I might add to date that approximately 99 percent of the effort that has been expended, the engineering effort by SNC Lavalin, has been done here in St. John's.
MR. JOHNSON:
Q. And whereabouts is Nalcor in phase 3?
MR. HARRINGTON:
A. This is Paul Harrington again answering the

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question. Phase 3, well we're working hard to get all of the information together to be able to make that decision gate decision and within, within this kind of phase, we're trying to get what is called a class 3 estimate and a class 3 estimate has a range of between 10 and 40 percent of project definition. So obviously the more project definition you can get, the more accurate or narrower the range on your accuracy for estimate that you will get. So currently all of those folks are working towards to get all of the information together to be able to come up with a capital cost estimate for DG3 of class 3.

MR. JOHNSON:

Q. Once the current assessment as to when all of the studies and investigations will be complete for the purposes of phase 3, so that you have reached your goal on project definition and your goal as regards to DG 3 cost estimates.

MR. HARRINGTON:

A. This is Paul Harrington again. We are, you know, striving towards achieving all of that

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information to give us a quality estimate of a level 3 in accordance with the association of the advancement of cost engineers, and that-- our current target is we should have all of the information together by June of this year to be able to make that decision.

MR. JOHNSON:

Q. As I understand it with the gateway model and in particular the gateway model employed by Nalcor, that the decision gate 3 cost in schedule estimates having been described in Nalcor's submission, as being a key input to verify the financial viability established at decision gate 2, and the materials would indicate that the intended purpose of DG3 is to verify the decision gate estimate in the schedule, to provide an increased level of confidence in outcomes required to facilitate the approval to move forward with project approval or sanction, and to establish the project budget, am I right so far?

MR. HARRINGTON:

A. That is a good summary.

MR. JOHNSON:

Q. Okay. Could you expand then on the notion of

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gaining an increased level of confidence in outcomes to facilitate approval and in particular, the outcome part first, what are we talking about?

MR. HARRINGTON:

A. Could you repeat the last bit, I missed it.

MR. JOHNSON:

Q. Part of the purpose of the DG3 work is to provide an increased level of confidence in the outcomes required to facilitate approval or sanction, and I'm interested in what are those outcomes that we're talking about.

MR. KEAN:

A. Okay. Again, this is Jason King, the outcomes that are certainly of importance to us are certainly linked to cost in schedule, as well as overall safety and environmental performance, and further, the reliability of the plant. So the work during this gateway phase 3, provides us with a level of confidence that we have fully understood the characteristics of the plant, how it will be built and how it can be delivered on time and on budget, and of course, maintain Nalcor's target safety excellence. So those are the

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outcomes that we refer to.

MR. JOHNSON:

Q. On the confidence piece, how much confidence do you require? How do you measure that confidence?

MR. KEAN:

A. The level of confidence required, you know, it's a bit subjection, you know, we have been focused on front-end loading the project such that the outcomes are very predictable, there is minimal uncertainty as to what the cost, the out turn cost will be, what the out turn schedule will be. So the final decision at DG 3 is somewhat subjective, but what we are doing is following a solid and sound process, best practice in terms of establishing a cost in schedule basis. You know, we are collecting significant amounts of engineering data, construction planning data and so on to facilitate the culmination of a project cost estimate. That is an extensive process, it takes a lot of time, a lot of effort and through that process we will identify certain uncertainties, certain risk, we will have taken steps to de-risk the project, to further

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understand the project. And as we approach decision gate 3, we will have gone through a risk assessment process and understood what the implications of those uncertainties could be on the project. And when I refer to implications, I mean cost in schedule implications, so we're able to make a, what I refer to as a risk-informed decision, we're able to state with confidence what we believe the likelihood of achieving a target cost in schedule is and we are able to make, you know, an informed decision as to whether we need to have certain contingencies, be it cost or schedule included there. So that's really how the decision will be made at that point.

MR. JOHNSON:

Q. And in terms of the project definition output, what's the goal of DG3, somewhere between 10 and 40 percent?

MR. KEAN:

A. Yes, that is correct, we are striving for the upper end of that.

MR. JOHNSON:

Q. Okay, and as regards the accuracy of the costing at DG3, what are we aiming for?

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MR. KEAN:

A. Our target, as indicated by Mr. Harrington, is to product a class 3 estimate. A class 3 estimate is a control level estimate. It is an estimate that you manage the execution of the project against. It's the estimate that you do your reporting against. The accuracy of the estimate is certainly, will be much tighter than what we have at DG2, very tight, and that will be influenced by the amount of front-end loading we are undertaking. As for the actual accuracy of that estimate, that can only be determined as we work through our process and undertake a review of those uncertainties through risk analysis techniques. So a process of Monte Carol simulation will be undertaken to facilitate, providing clarity as to what the actual range of that estimate would be.

MR. JOHNSON:

Q. So, in other words, if one were to read in the AACE that a class 2 estimate or a class 4 estimate has a certain range, you know, in the textbooks, you are trying to narrow in on the--on what the true probability is.

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MR. KEAN:

A. Yes, that is correct.

MR. JOHNSON:

Q. Okay, and what would be the textbook range for DG2 verses DG3?

MR. KEAN:

A. I guess from a textbook perspective, we've stated that the DG2 estimate would have generally a range of minus 30 to plus 50, whilst a DG3 estimate should be in the range of minus 10 to plus 20. The actual variability would be confirmed at the point of when we've concluded our process and assessed the quality of the base estimate.

MR. JOHNSON:

Q. Okay, and DC4, then you're back to--you're commissioning then, right, okay. Now let me try a report as you're familiar with, related to the project components and costs as of DG2, because they indicate that they did not have access generally to information on the detailed engineering or financial work completed after DG2. Can Nalcor explain why information post DG2 couldn't be made available?

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MR. HARRINGTON:

A. You know, we made every effort to respond to all of the information requests to provide the information that we had available, but as you can appreciate, you know, the large amount of work sometimes just doesn't end up with a final report. There is ongoing activity where multiple disciplines are involved as well, so we are not in a position, even now, to actually provide you with a nice bound set of there are some final reports. It's ongoing work and just as an example of the complexity of the estimate that's being put together, there are approximately 50,000 line items with over 100,000 date points, so all of that information is coming together. So, you know, we've provided as much information as was available to us.

MR. JOHNSON:

Q. At DG3, I understand all inputs done to the CPW analysis are going to be updated with the latest available information, sometime in June or, I think would be the prediction, would that be right?

MR. HARRINGTON:

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A. Yes, we're targeting to get, well the capital cost estimate and the work that we are doing is just one element of the CPW analysis.

MR. JOHNSON:

Q. True, true, which leads to, I think where I was going, because up to that point, you're going to be updating your capital cost estimates, including your base costs, your contingency, your escalation allowance, you'll be updating where you think you will be on scheduling, update of fuel prices, updated demand forecasts, interest rates, exchange rates, and Power Purchase Agreement, all of those get updated at that point. And in terms of, there was some reference in the presentation this morning about the ability to incorporate responses to requests for proposals for major equipment deliverables, and I understand that will be taking place in DG3, but did it also take place in DG2 in terms of the cost estimates?

MR. KEAN:

A. No, it did not in terms of DG2. We did not have a sufficient level of engineering complete to be able to issue request for

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proposals, rather we did issue inquiries for budgetary quotes for major items, including our turbine and generators, submarine cable, convertor stations, key transformers, really the bigger pieces of hardware that would be required to construct the facility and for which there could be cost variability.

MR. JOHNSON:

Q. I guess the question would be whether there could be significant changes between inputs used at DG2 and inputs used at DG3? I presume that there could be.

MR. KEAN:

A. Yes, that is correct.

MR. JOHNSON:

Q. And is it possible to give us any insights as to where, you know, those changes might be found or what might be anticipated in that regard?

MR. HARRINGTON:

A. As I mentioned, you know, it's difficult to predict the outcome based upon incomplete activities, with you know, I wouldn't be doing my job if I were to second guess the work that's being carried out right now by a team

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of estimators and engineers to develop all of those data points, over a hundred thousand, as I mentioned earlier, to be able to guess or second guess what the capital cost outcome might be. I have to have faith in the process to get us to that point, so I have no indications either way at the moment.

MR. JOHNSON:

Q. At this stage we know from the record that there are some additional information to consider, there's an additional oil price forecast for May of 2011 and since DG2, there was also a commitment to provide a loan guarantee, and I guess in connection with the reference question that the Board has before it, what use should we make, the Board make, of this updated information, if any in the context of the review question?

MR. HARRINGTON:

A. I think that might be--not for me.

MR. HUMPHRIES:

A. Yes, this is Paul Humphries, there are a number of inputs, besides the capital cost that are going to go into this evaluation, there is the effect of the loan guarantee,

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there is the effect of a new fuel forecast and load forecast and there may be puts and takes on all, and to say with any level of confidence what that would have in the ultimate outcome, we're not in a position to do that now because we don't have all the inputs, but if you look at the sensitivity analysis that we did complete, that will give you an indication of the directions in those independent variables, good point.

MR. JOHNSON:

Q. What, as at DG2 there had not been a commission from Canada to provide the guarantee, so what use was made of the prospects of receiving the guarantee in relation to the Muskrat Falls Labrador-Island Link Project for DG2, from the DG 2 recommendation?

MR. BENNETT:

A. Yes, this is Gilbert Bennett, the DG 2 analysis did not assume that the federal load guarantee was in place and that we would be financing the project using a conventional project financing approach for the transmission assets and a hundred percent

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equity for the generation assets.

MR. JOHNSON:

Q. I want to zero in a little bit more on the cost estimate input, in particular in relation to the Muskrat Falls Labrador-Island Link, and just start with the general observation that was made in Nalcor's submission that it is typical for the capital cost estimate to evolve as the project definition matures, and of course, we know that the cost estimates are broken down into base cost, contingencies and escalation allowances. In terms of the contingency part, explain what we mean by "contingency" because I understand we have a 15 percent contingency on a big project and what would be captured by that contingency?

MR. BENNETT:

A. The contingency, the estimate of contingency is designed to address for unknowns in the estimate elements, basically. We talked about in the presentation the estimate having four major inputs, the base estimate, so as you can appreciate there is variability in each of those main elements. So in order to capture the variability we try to understand certainly

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the--try to quantify that variability and make an assessment of that through a process of Monte Carlo simulation. Now we have and continue to use an industry recommended practices for that process, further we have engaged our consultant, Westney Consulting out of Houston to support that assessment. So it's a fairly thorough assessment. In the case of DG2, our recommended contingency was validated by an independent project analyst during our decision gate 2 analysis and they indicated that we were where we need to be for the review and the level of maturity of the project.

CHAIRMAN:

Q. What do you mean by "Monte Carlo", I mean, that's not a--do you know what that means Mr. Johnson?

MR. JOHNSON:

Q. I think it has to do with dots being put on a page to give you a sense of the probability of where you're going to end up between ranges, would that be accurate or somewhat accurate?

MR. BENNETT:

A. Somewhat accurate, I think there are -

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MR. JOHNSON:

Q. I shouldn't have fallen (phonetic) it.

O'REILLY, Q.C.:

Q. Somewhat accurate means you're not completely wrong.

CHAIRMAN:

Q. You know what we all think of when we think of Monte Carlo, we think we're rolling dice or something else equally as -

MR. BENNETT:

Q. Well I can't speak to all of the origins of the technique, but it is a sampling technique whereby, you know, probability of events are evaluated and the culminated effect of potential events that occur, come up with a recommendation or a distribution of outcomes and you choose from an outcome based upon the level of confidence that one would wish to have.

CHAIRMAN:

Q. So it's a question type, probability, I guess, is it?

MR. BENNETT:

A. It is, P10, P90, those things.

CHAIRMAN:

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Q. Okay, that makes sense, I understand that.

MR. JOHNSON:

Q. This concept of capital costs evolving as the project definition matures, would--does that generally mean that the estimate typically increases as a project definition matures, albeit in a narrower range of accuracy?

MR. BENNETT:

A. No, it doesn't mean that the estimate increases, it means that as the estimate matures, there is less variability in each of the inputs, you have greater certainty on all aspects of the estimate, be it major quantities, you know, wage rates and so on, you've done the investigation to verify that.

CHAIRMAN:

Q. So, it's a rising P.

MR. BENNETT:

A. Yes. So it's an extensive process, and only by the process of front-end loading and undertaking necessary engineering investigations can you get to a point of having confidence in the inputs to your estimate.

MR. JOHNSON:

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Q. Could we turn up, Mike, page 71 of 92 of the Nalcor submission? In particular, it's Table 2. It's volume 2. And here we have a summary of the Muskrat Faffs and Labrador-Island Link capital cost estimates for DG2, which would indicate, as we can see on the screen, a base estimate for the Muskrat Falls generating facility of 2.2 billion, there was historical costs of 20 million pre to 2010 and then you minus those historical costs to come up with your adjusted base costs, you add your contingency and escalation allowance and we see similarly in the next line down, the Labrador-Island Transmission Link costs, which totalled to 2.06, but of course, that summary does not include the contingency or the escalation allowance and--no, I'm sorry, it does, it includes the 670 million combined estimate contingency and escalation allowance for Muskrat Falls in generating, and about 444 million in combined estimate, contingency and escalation allowance for Labrador-Island Transmission Link, so that's sort of the big picture of the costs and I want to drill down a little bit further now and a convenient

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place to do that is actually Exhibit 101, which is the Navigant Report on page 38, which gives a breakdown of the components of each of the projects or of the Muskrat Falls and Labrador-Island Link Project. In particular I'm looking at Table 4 on page 38 of the Navigant Report.

MR. HARRINGTON:

A. Excuse me, we don't seem to have that table. Is the reference correct?

GREENE, Q.C.:

Q. There may be a difference with the page reference on the exhibit, verses the page number in the actual report.

MR. JOHNSON:

Q. Okay. Oh, I'm sorry, so it would be page 38 of the exhibit then--no, page 31 of the report.

GREENE, Q.C.:

Q. You're looking for Table 4, keep going. There.

MR. JOHNSON:

Q. Thank you, so these would be the components of that cost estimate for Muskrat Falls and the Labrador-Island Link. Now, as we look at

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these, we can leave these on the screen for a moment and we'll get back to them, but I take it that it's true that as the project definition increases, so does the accuracy around the costs, I think we've established that. And I take it that there is a consensus that there were varying degrees of project definition as amongst the various components of the Muskrat Falls Labrador-Island Link Project at the time of DG2, would that be fair?

MR. KEAN:

A. Yes, that is correct.

MR. JOHNSON:

Q. Okay, and as a matter of fact, that's a point confirmed by Manitoba Hydro International's report at page 35, because they make the observation that DG2 used a class 4 accuracy level at the study or feasibility stage. At GD3, Nalcor proposes to use a class 3 accuracy level for the budget authorization or project sanction stage and they say "Typically in the early steps of a project's development, a mix of cost estimate classes would be used as evidenced by what MHI has seen in the case of

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Muskrat Falls generating station and the Strait of Belle Isle marine crossing which were studied more extensively than the other components." So would you agree with their characterization that these were studied in fact more closely than the other components?

MR. HARRINGTON:

A. I mean, studies are very difficult to compare, but I mean, I think it's fair to say that there's been different effort put into different areas.

MR. JOHNSON:

Q. And there's no disagreement, I was just--if we could turn up page 75 of 92 of the Nalcor submission for a second, there's reference made to, in the case of Muskrat Falls Generating Facility, Nalcor says that "In the case of the Muskrat Falls Generating Facility, where detailed definition exists, significant portions of the base estimate have been developed using a comprehensive and detailed approach working from the lowest level of detail and building the estimate up, using available information on quantities; unit cost; wage rates; bulk construction;

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consumables, example: Portland Cement; diesel fuel; rebar, et cetera; construction fleet cost; major permanent quotations and historical production rates. In some areas, such as the balance of plant and spillway gates, third party benchmarks from as-built plants combined with current unit costs have formed the basis of the estimate." And I guess the question that I would have is what degree of project definition would Nalcor ascribe to the Muskrat Falls Generating Facility, having regard to how you've described it in your submission?

MR. HARRINGTON:

A. So just repeat the question because we were just kind of bouncing--so what degree of completion at DG2?

MR. JOHNSON:

Q. At what degree of project definition.

MR. HARRINGTON:

A. At DG2?

MR. JOHNSON:

Q. At DG2.

MR. HARRINGTON:

A. Okay, at DG2, you know, I think we were

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consistent with a class 4 estimate and the class 4 estimate--if I have my papers together, is in the region of up to 5 percent of project definition.

MR. JOHNSON:

Q. If I could address your attention to figure 7 at MHI's report, which occurs on page 35 of their report.

MR. HARRINGTON:

A. All right.

MR. JOHNSON:

Q. Volume one. Right here at figure 7, we have a graphic representation of the AACE cost estimating accuracy classes.

MR. HARRINGTON:

A. That's correct.

MR. JOHNSON:

Q. And the way I read that graph along the horizontal access, is that a project that has somewhere between 3 to 15 to 18 percent degree of project definition would be considered class 4, would you read it the same way as I do?

MR. HARRINGTON:

A. I can't read it from this--okay, I'm trying to

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read it from that, but it's a little bit difficult. So in the middle of class 4, I see 10 percent, right?

MR. JOHNSON:

Q. Okay, yes. And so I guess what I'm trying to get at is that it seemed to me, based upon Nalcor's submission, where the submission spoke about detailed definition existing for significant portions of the base estimate, et cetera, I invite your comment on where you would find your Muskrat Falls Generating Project fitting on that degree of project definition as at DG2?

MR. KEAN:

A. Just from a degree of definition certainly suitable for a class 4 estimate in accordance to AACE international recommended practices. The graphic that's displayed there is representative of projects in the process industry and going back to Mr. Bennett's presentation this morning, many of the characteristics of our Muskrat Falls' site lend itself to much more predictable costs because of its--I guess it's not lending as much new technology and so on, so what you

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would see, you would see--if this graph was designed directly for Hydro projects, you would see this shrinking considerably and conveying that there is more certainty in the costs of a class 4 estimate than what this graph actually indicates.

MR. JOHNSON:

Q. I guess in relation then to the comment about the Strait of Belle Isle Marine crossing, as MHI referred to that as another example of use of mix classes of costing accuracy, and I think Nalcor's submission refers to the fact that there was extensive field work and studies completed for the Strait of Belle Isle cable crossing, a similar question would be what degree of project definition would Nalcor ascribe to the Strait of Belle Isle marine crossing as a DG2?

MR. HARRINGTON:

A. Okay, so with regards to the Strait of Belle Isle, you know, MHI were quite correct, you know, we did feasibility type work to arrive at the DG2 study--the DG2 estimate, so that included some site investigation work, but just to illustrate how we're moving from that

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DG2 to DG3, we're currently or we have carried out this year a marine survey work of the actual Strait of Belle Isle, which has allowed the feasibility engineering work to start moving into that detailed engineering work. We're also carrying out a, a pilot call for the horizontal directionally drilled holes that Mr. Bennett referred to in his presentation, which will get the cables down to a deep point in the Strait of Belle Isle which will then avoid iceberg contact and pack ice contact. So to give you an illustration of that, is that more than five, ten percent? That's--it's very subjective in that regard.

MR. JOHNSON:

Q. But certainly, you would have a lower -- to the left of the horizontal line, to the left side more to -- than to the right?

MR. HARRINGTON:

A. I think this one, you know, I think MHI also identified that, you know, we were pretty much on the class four estimate. So, I'm comfortable with the fact that with all of the puts and takes, you know, some areas may be a little bit more advanced than others, but

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overall, in the aggregate, I think we meet the class four estimate.

MR. JOHNSON:

Q. Okay, okay. Looking at PUB-Nalcor 42, and this is again a question that was asked from the Board having to do with degree of accuracy, if we could turn that up for a second? The question indicates that -- at page six of Exhibit 31, it stated that "the current capital cost estimates for the Muskrat Falls Project Labrador-Island transmission link were prepared for the purpose of Decision Gate 2" and on page seven it stated "this cost estimate is commensurate with an AACE international class four estimate." Then it just asks "what degree of accuracy is usually attached to the class four estimate?" and the answer goes on to indicate that according to AACE, you can have the recommended practice which is referenced there "a class four estimate can be minus 15 to minus 30 on the low side to plus 20 to plus 50 on the high side, depending upon the technical complexity of the project, degree of project definition, percentage of design complete, appropriate

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reference information," and then the answer goes on to indicate further down that "these ranges are not absolute and are not industry or project specific" and if you could go further down again, Mike, it says "in summary, the estimate accuracy will be generally correlated with estimate classification and therefore the level of project definition, all else being equal. However, specific accuracy ranges will typically vary by industry. Also, the accuracy of any given estimate is not fixed or determined by its classification category. Significant variations in accuracy from estimate to estimate are possible if any of the determinants of accuracy, such as technology, quality of reference cost data, quality of the estimating process and skill and knowledge of the estimator vary" and continuing on, "accuracy is also not necessarily determined by the methodology used or the effort expended. Estimate accuracy must be evaluated on an estimate by estimate basis, emphasis added, usually in conjunction with some form of risk analysis process."

And I guess, having regard to all that,

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because Nalcor went at some pains to explain that you must take an estimate-by-estimate approach and I understand that. Having regard to that, can you give us the degree or range of accuracy used by Nalcor with respect to its DG2 estimates for the Muskrat Falls Project Labrador-Island link that have been provided in this review on some sort of overall basis? Because you've said it's sort of an estimate by estimate, case by case, so can you assist us in trying to narrow in on that range of accuracy?

MR. HARRINGTON:

A. As you point out, the class four estimate range can go from a wide range of minus 30 to plus 50. So there's an equal probability of it being over 50 percent as it is to being under by 30 percent. In the narrower range because -- and again, this is the standard that's out there -- the narrower range is plus 20 percent to minus 15 percent. So there's equal probability. It's a distribution curve around that point. We carry out a risk analysis, as is recommended by the practice here, to be able to set -- and that's why we

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landed on our contingency amount of 15 percent. So, you know, we feel, based upon the industry and the amount of work that's being carried out, that we're, you know, within the class four estimate ranges of estimate.

MR. JOHNSON:

Q. So, I guess to zero in, your best assessment as at DG2 would be you'd be more in the middle of -

MR. HARRINGTON:

A. Not in the extremes. We're not at the -

MR. JOHNSON:

Q. Not at the extremes?

MR. HARRINGTON:

A. No, not at extremes.

MR. JOHNSON:

Q. Okay. And more around the plus 20 to minus 15 in your assessment?

MR. HARRINGTON:

A. You're pushing me a little one on that one, to be absolutely, you know, precise upon a DG2 estimate where it admits there's a range of things.

MR. JOHNSON:

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Q. I understand, and was the Monte Carlo type process -- at the risk of going into that again -- was that type of an analysis brought to bear on that particular issue?

MR. KEAN:

A. Yes, that is correct. In June 2010, we did undertake a risk analysis, full comprehensive analysis of tactical risk, i.e. those risks that the items of the estimate could be high or low, to understand the appropriate contingency to be used on the estimate.

MR. JOHNSON:

Q. And just to sort of circle back for a second, I take it you're getting your comfort level about that range not so much from the degree of project definition, because even at that time, you've indicated project definition, even on the things that you had most extensively studied, wasn't to the right too far on the graph. So you're getting that certainty or confidence from other issues and what are those other issues and considerations that are bending towards that middle of the road?

MR. KEAN:

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A. Through, I guess, having a thorough understanding of the estimate and its input, the quality of the input into the estimate, we are -- you know, we are confident -- I guess you might say much more confident in the quality of the range, what the range or variability may be around that estimate. So, we went through a painstaking process of doing a bottom up estimate in many aspects of the project to have clarity on that, on those input factors and by doing that assess the uncertainties associated with those input factors.

MR. JOHNSON:

Q. Can you give us like a concrete example of something that was a factor or an indicator that made you conclude "you know what, I think we've got a bit more comfort level because of X"? Can you put it in those terms for us?

MR. KEAN:

A. One aspect of that would be the benchmarking we had done with other hydropower developers in Canada, as well as with other companies on equipment, construction equipment, fleet hourly run rates and so on, so the cost to run

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an excavator every hour. We did a considerable amount of benchmarking on that with other developers in Canada. As well, in the context of productivity and performance, we engaged Caterpillar and did a fairly thorough modelling and assessment as to what productivities we may get for various excavation and backfill requirements. So activities such as that gave us good confidence in the base numbers that were provided in the estimate.

Further, in the context of labour, which is a fairly significant portion of the cost estimate, when we did our DG2 analysis, we did have the Vale labour agreement. It was negotiated. It did serve as good input into the estimate and it's provided clarity as to labour demarcation that we may expect to see at the Muskrat Falls site. So that was another key input, and you know, through, I guess, the numerous inputs of that nature we went through one by one looking at what would be the base case premise for that input, how solid a foundation was that input and what variability could we see in that input.

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So, through a process of benchmarking, engagement with third parties, third party specialists, you know, cold eyes review and so on, we came upon landing upon base inputs into the estimate and we also came upon an assessment of what the variability might be in each of those inputs and that combined variability gives us a view of what the overall accuracy of the estimate would be at DG2 and of course sets the work plan as we move forward into gateway phase 3 and to get the solid control level estimate in place for sanction.

MR. JOHNSON:

Q. This is probably a convenient time to break, Mr. Chairman.

CHAIRMAN:

Q. Thank you. What time are we reconvening? 2:30. Okay. Alright, 2:30 then, ladies and gentlemen.

(LUNCH BREAK)

(2:30 p.m.)

CHAIRMAN:

Q. Mr. Johnson, I think we back in your capable hands.

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MR. JOHNSON:

Q. Thank you, Mr. Chairman. To further develop the discussion around risk, and we will talk about the risk of the other option too, we recognize that there's risks associated with world oil prices and environmental costs associated with electricity generation through thermal means, and I want to have a discussion for a second about construction project risks, and tell us what are the elements of these construction project risks, what are you talking about?

MR. HARRINGTON:

A. The typical construction risks that we're talking about are any construction project has challenges. We like to look at Muskrat Falls, in particularly, and I think it was mentioned in the presentation earlier that it has a lot of positive attributes of the site. We know that site very well from a geotechnical perspective. We've carried out many, many years of drilling and coring and finding out what the bedrock is. So we have a good feel for that construction risk because it is - geotechnical is a construction risk. So by

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having a good knowledge of what the rock is that you're dealing with and how much overburden you have to remove, it mitigates that risk. So we've been carrying out a lot of work to be able to identify the rock that we're building the dams upon. Another construction risk is making sure that you've got the right physical layout of the facilities, making sure that the water flows are going to be correct. That's a construction risk. If you don't get that right, it's not going to give you the right amount of power output that you're predicting. So what do we do there, and what have we been doing over the last 12 months, is building a physical model of the Muskrat Falls site, so we can verify the mathematical modelling that's being carried out on water flows. We can actually see the physical flows using the physical model. So there's another construction risk that we've mitigated to that degree. The other construction risk that we are facing is having the labour force that we require because obviously labour is a commodity, is a resources that we're all

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striving for with lots of projects on the go in Newfoundland and Labrador, Atlantic Canada, and indeed in Western Canada. So all of these things we've looked at and we've mitigated that risk by identifying it early. So when it comes to labour, what we first identified is what is our demand, what does the project require with regards to form workers, truck drivers, you name it, all of the different national occupation codes. So we did that very early in the process at DG2. We provided that information to Government, so that they could then implement training schemes within their jurisdiction to try and meet the requirements of not only Lower Churchill Project, but indeed lots of other projects that were on the go. So they all provided a similar type of thing. These are the national occupation codes that we need to carry out the project over this period of time. They put all of those things together, so we as a project, by very clearly identifying our labour requirements, we were able to participate in that activity, skills gap workforce was one of the outputs of that. We

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also have met with a large number of educational facilities to give them prior warning as to what type of skillsets that we need, and again what we look at is what are the other projects on the go. Our project is primarily a civil project. So we don't require the skillsets that lots of other projects need when it comes to mechanical, piping, electrical, and instrumentation. Those are the ones that are more process orientated. So, for example, if you were doing an upgrader in Western Canada, you need a completely different workforce than we need, and that workforce normally requires four to five years extensive training and previous experience in that regard as well. So we identified there may be a labour risk, so we mitigated it by identifying our needs very clearly, working with the educational and government to try and address the training gap. We went further than that. We also realized that there were under-represented groups in the workforce who don't usually get the opportunity. In Labrador, for example, we have actively participated in the Labrador

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Aboriginal Training Partnership, LPTP, because we realized there's an untapped workforce there and we are pleased to say that over350 people in Labrador are being trained to be able to participate in not only our project, but other projects as well. So we tried to address all of the needs that we can by participating in all of these activities I've just described. So having the labour, having a clearly defined plan, and using the fact that we're on a good solid work site in one place, we'll come up with a very attractive camp, we have a decent working rotation, and we'll have a competitive remuneration package as well. So all of these things will contribute and mitigate in construction risk when it comes to labour.

MR. JOHNSON:

Q. There is mention, I think as well, of a project agreement with labour unions. Was that early enough in the works for DG 2 purposed?

MR. HARRINGTON:

A. In DG 2, we carried out a complete survey of all of the special project agreements that

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have put in place across Canada, and by taking all of that information, we've identified what we believe to be a very positive and constructive labour agreement strategy. We're in the process of going to enter into those negotiations with the appropriate union bodies.

MR. JOHNSON:

Q. What are - how about risks in relation to the so-called LIL, because we've - I'm sure labour comes into that as well.

MR. HARRINGTON:

A. Yes.

MR. JOHNSON:

Q. But you spoke about the geotechnical aspects of the dam site. How about those risks?

MR. HARRINGTON:

A. Okay, Labrador-Island Link, of course, one of the early identification of risk was the Strait of Belle Isle. So we established a team specifically to look at the Strait of Belle Isle to engineer our way around the pack ice issues, to engineer our way around the iceberg concerns that were in that, and we believe we've done a pretty good job of doing

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that, and I think MHI even recognized that in their report. So that was one of the biggest areas of risk. The other area of risk on the Labrador-Island Link, I would say would be the Long Range Mountains, and The Long Range Mountains and its particular ice conditions that it will be facing. So we looked at that area and said, yeah, that's an area of risk, so what did we do; we engaged some world class individuals from both Iceland and Norway who have got particular experience in the type of ice that will form in those Long Range Mountains. They've been extremely successful in engineering their way around those types of conditions. So we've taken that into account. They're still participating in our activities. We even put a couple of tests on in that area so that we can monitor the success, the idea of let's put a tower there, let's put a tower there. So all of those things are coming into mitigating the risk in The Long Range Mountains.

MR. JOHNSON:

Q. You mentioned a test carried out in that area. What did you refer to it as?

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MR. HARRINGTON:
A. We built a tower with a conductor string strung across it, so we're monitoring the ice build-up on it, and over time we'll be able to incorporate that into our future plans.
MR. JOHNSON:
Q. Because I - actually, it's funny you should mention that. I had a call from a gentleman from Carbonear and he wanted me to ask you whether you have undertaken any stress tests of, you know, the transmission line and whether that data would be publicly available and just some background on what you've done in that regard. So that stress testing, is that ongoing now?
MR. HARRINGTON:
A. It's ongoing every winter.
MR. JOHNSON:
Q. Yeah, okay, yeah.
MR. HARRINGTON:
A. Until we start building.
MR. JOHNSON:
Q. Okay. Let me ask you then what are the - what are the elements of risk that fall under construction project risks that are the most

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difficult to mitigate?
MR. HARRINGTON:
A. I might throw that one to - have you got any particular ideas, or have I covered all of them. I don't know.
MR. KEAN:
A. From my view, probably the greatest aspect deals with labour and labour productivity. You don't always know on a construction site the quality of the labour that you're going to attract and their capabilities and so on. Labour productivity is influenced by a lot of aspects. A lot of things that can be done in the office during the engineering phase, for instance, to enhance labour productivity, or the way we organize the site. You know, everything from winterization provisions or the way the site is laid out, the site services and so on. So we recognized early that labour productivity or the productivity of the worker can negatively impact the job unless we take proactive measures. So going back in actually 2008, we engaged a consultant out of University of Calgary to work with us to develop a productivity action plan.

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Through that and through evaluation of various work sites and lessons learned, we determined what are the key drivers of construction productivity, and how can we look at those in the context of our site, what can we do to mitigate those. So we're trying to get out ahead of the issue to understand, first, is it going to be an issue for us, and how can we knowing the issue, try to understand the implications of that, and then how can we mitigate it. Mr. Harrington spoke about some of the things on the mitigation perspective in terms of understanding labour supply and demand, training of individuals and so on, but there's a lot of things that we're doing in the engineering phase that will also mitigate that key risk.
MR. JOHNSON:
Q. Are there any others that fall under the category of difficult to mitigate?
MR. KEAN:
A. Probably, you know, you could classify weather type related issues in there. So, of course, from a planning basis, you know, such as in the Strait of Belle Isle, weather from a

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seasonality of construction installation is important. So that drives us to collect as much data as we can. This past year, for instance, we had undertaken a marine seismic program and it was the first time that what we refer to as work class ROV, remotely operated vehicle, was used in that area. It's very similar to the ones that you see downtown on back of the orange supply vessels. So we actually used one of those vessels in the area. So understanding the limitations of that machine in that terrain is very important, so we can plan our installation program very effectively. We can look at what the hours of work is going to be. You know, there's been concerns or there have been, I guess, concerns about currents in the past, so we've done a thorough understanding - thorough assessment of that. So we understand that very thoroughly what the limitations are.
MR. JOHNSON:
Q. In terms of, you know, if you see the Class 4 estimate and the textbook says, you know, it could be -30, +50, customers wouldn't really be worried about -30, but they would probably

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be quite concerned about a +50, and I'd like some - a bit more insight as to, look, what's the likelihood that this is +50 from DG 2 estimates, what's the likelihood of +25, you know, and, I guess, two neighbours on the same street could build the identical on identical land, and one fellow having a 50 percent overrun and the other fellow comes right in on target, and I'd like to know what are those probabilities, what are those likelihoods within that range?

MR. HARRINGTON:

A. Well, I would say that +50 percent, - 30 percent, are on the extreme edge. I don't believe that we will be there, I don't believe. I think we'll be closer to the narrower range, which is -15 to +20.

MR. BENNETT:

A. This is Gilbert Bennett. I just might add some broader context to that. I think at the end of the day if you look at the techniques and approaches that are used in the industry for estimating, there is a level of uncertainty, but there is a set of best practices, and the intent of those best practices is to pull

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yourself from the extremes of the range closer in, and as we progress with engineering definition, we reduce that uncertainty. As we continue to focus on issues that have been identified as risks early in the work program, and understand them better, the whole concept of front end loading, that serves to reduce that risk, but the establishment of what those risk ranges are, that comes from a probabilistic analysis and that's something that will continue to be done as we continue through the design progression. So it's not really appropriate for us to say, well, we think the range is this or that at this point in time, but to continue with the process that we're following and to continue to define the project, with a view to minimizing that range.

MR. JOHNSON:

Q. I guess what I'm trying to focus in on is as of DG 2, how likely is it in your assessment that we're going to pitch somewhere between the narrower range that Mr. Harrington spoke about?

MR. BENNETT:

A. We think there's a much higher probability of

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being at that point than being at the extreme edges using the techniques that we've identified and the practices that are being followed.

MR. JOHNSON:

Q. Okay. In terms of the risks of the isolated option, there is world oil prices and risk is not necessarily a bad thing because oil prices could drop, risk goes both ways, but I want to focus first on the environmental cost risks associated with the isolated option, and in relation to this greenhouse gas business that was raised in the MHI Report, I think MHI spoke about a likelihood of some greenhouse gas regulation that could impact upon Holyrood. What's Nalcor's assessment of that risk?

MR. BENNETT:

A. I think based on what we have seen, what we have heard from the Government of Canada, we agree that there's a risk. We've not quantified that risk in our analysis. Our analysis, our baseline CPW comparison did not include a cost for carbon, but the messages - I think there are fairly clear messages in my

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mind from the Government of Canada, so the introduction of greenhouse gas regulation for coal fired generating facilities in this country is a sign for us, and I think that there is - and the establishment of the emission limit of those facilities at the same level as a gas fired facility is a clear indication that the Government intends to do something about GHG emissions across our economy. Now we don't have complete clarity as to when they would do that for other facilities, but we have noted that the emissions intensity from Holyrood is greater than that of a combined cycle plant. So we think there's a concern or a possibility that that could happen. It's not in our analysis, but we did identify that the possibility exists.

MR. JOHNSON:

Q. And you added it as a sensitivity, and that would be - your sensitivity involved if there was basically a tax on carbon?

MR. BENNETT:

A. A cost of carbon, that's right.

MR. JOHNSON:

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Q. And when did you assume that that tax on carbon would come about for the purpose of your sensitivity?
MR. GOUDIE:
A. Steve Goudie here. I think it would have been earlier rather than later. I'm not quite sure of the exact date. It would not have been, like, in 2020 beyond, it would have been -
MR. JOHNSON:
Q. Prior to that, okay. Maybe you could - Mr. O'Reilly, if you could just see if Nalcor could provide clarity on when that date is, and I apologize if it's not on the record, or if it's on the record and I overlooked when that kicked in.
O'REILLY, Q.C.:
Q. Okay, we'll locate it. Thank you.
CHAIRMAN:
Q. When what kicked in?
MR. JOHNSON:
Q. When they are assuming that the carbon tax would have been applicable because they added their sensitivity - on their sensitivity, I think they said a half a billion dollars, and I'm just sort of interested when they were

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anticipating that carbon tax would have kicked in.
O'REILLY, Q.C.:
Q. So you want the date that they - for the purpose of their sensitivity analysis, the date that the thing went in?
MR. JOHNSON:
Q. Yes.
O'REILLY, Q.C.:
Q. We'll dig that out.
MR. JOHNSON:
Q. Thank you very much.
CHAIRMAN:
Q. And I guess you'd want it cost per ton too, wouldn't you?
MR. JOHNSON:
Q. Yeah, I think there was a cost per ton reference in the record, but might as well provide that as well. In terms of - that's the price risk, the obvious price risk is the carbon tax on per ton, and I understand MHI's Report made reference to the fact that over a five year period from 2005 to 2009, the Holyrood generating facility generated 866,000 tons per annum of carbon dioxide, and is that

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the number that your sensitivity test was built around or was it built around the projection going forward of the load that Holyrood was going to carry?
MR. BENNETT:
A. That sensitivity would have been completed based on the forecasted generation from Holyrood.
MR. JOHNSON:
Q. Okay. MHI's Report stated that - and just for the record, page 171, "The greenhouse gas emission standards are likely to be set by the Federal Government, and as such, pose a risk to the ongoing operation of HTGS, Holyrood Thermal Generating Station, as a generator". So is that suggesting or as part of your risk analysis is that there's a possibility that the Federal Government could say that place has got to shut down, and you can't be generating electricity like that in the future? Is that what we're talking about there? Would it be that stark?
MR. BENNETT:
A. Well, that possibility exists and the Federal Government has said that for coal fired

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facilities.
MR. JOHNSON:
Q. And how much time did they give these coal fired facilities to mend their ways?
MR. BENNETT:
A. They have - for facilities, as I recall now, it was the facilities that have reached a 45 year design life, if they've been in operation for 45 years, they're expected to shut down after 2015. So there are several other provisions in the regulations. If there's a commitment to implement carbon capture technology, they have some additional time, but in the 2015 to 2025 time frame, coal fired plant operators have to find a way to comply with those regulations. Now I think it's important to point out that those regulations have not been finally implemented. They have been gazetted, and they're open for comment, but have not been absolutely finalized, but I would agree with MHI that there is a fairly clear signal from the Government of Canada that it intends to do something with coal fired facilities.
MR. JOHNSON:

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Q. And I guess it's hypothetical, but for the customer who is watching the proceeding, explain that risk to them, what does that mean to them?
MR. BENNETT:
A. Well, the -
MR. JOHNSON:
Q. What is the cost implication of this if that were to happen and that you had to do something else on Holyrood?
MR. BENNETT:
A. The potential at Holyrood would be to replace that plant with a more efficient and less intensity - lower intensity facility.
MR. JOHNSON:
Q. And I guess your suggestion is that that would,I take it, further add to the economic cost of this isolated model?
MR. BENNETT:
A. Yes.
MR. JOHNSON:
Q. Is that what they take away from that?
MR. BENNETT:
A. It would further improve the preference for the interconnected alternative for that risk,

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as we talked -
CHAIRMAN:
Q. Excuse me, is that the two billion dollars you referenced, Mr. Bennett?
MR. BENNETT:
A. Yes. So if you imposed a cost for carbon or if you forced the early replacement of Holyrood, 2.2 billion dollars would increase - that preference for the interconnected scenario would increase.
CHAIRMAN:
Q. That's not the carbon price, that's what the cost would increase by?
MR. BENNETT:
A. It would increase over and above that amount. The 2.2 billion is the CPW difference between the two alternatives.
CHAIRMAN:
Q. So if I divide the number of tons into 2.655, I get the cost per ton?
MR. BENNETT:
A. No, sorry. The difference between the 2.2 and the 2.665 is the cost of carbon that's -
CHAIRMAN:
Q. Oh, yes, okay.

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MR. BENNETT:
A. All right.
MR. JOHNSON:
Q. And that's the - the Chair raised the cost of the carbon, how that would change the CPW preference calculation, and I guess my question is an order of magnitude of if you were - if some regulation came in, and said, look, you've got to retire this facility by 2025 or however, you know, what would that mean from a cost point of view?
MR. BENNETT:
A. We haven't specifically done the analysis to bring the replacement of Holyrood into 2025, but it would increase the cost of the isolated island scenario because you're forcing the replacement of Holyrood with a new facility and the number two fuel in that plant is more expensive than the number six fuel that's currently burned on a per megawatt basis.
MR. JOHNSON:
Q. And in relation to the isolated case, there is - in your isolated scenario there is spending a considerable sum of money on precipitators and scrubbers. When is it that you would

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propose to do that in the event that Muskrat is not sanctioned?
MR. BENNETT:
A. Well, in the event that Muskrat is not sanctioned, the province has indicated that we are to proceed with that immediately.
MR. JOHNSON:
Q. Okay, and I take it that has a 500 million dollar cost?
MR. BENNETT:
A. That's right.
MR. JOHNSON:
Q. Or something in that vicinity.
MR. BENNETT:
A. Approximately 600 million.
MR. JOHNSON:
Q. And I guess the question I would have is, as I understand it, that - those precipitators and scrubbers wouldn't take the greenhouse gases out of the air, and there's some suggestion in the MHI Report that, well, you know, does that make a lot of sense spending that type of money if you could just switch to the cheaper or the more expensive oil, the lower sulphur content oil. So the question is why would you

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go with precipitators and scrubbers if you can just stick with the lower sulphur content oil?

MR. BENNETT:

A. Today we do burn 0.7 percent sulphur fuel at Holyrood. I think it's fair to say that the Holyrood facility, emissions in particular from that facility have been of significant concern in the communities on the North East Avalon, particularly the Holyrood, Seal Cove, and Conception Bay South area, and in response to those concerns - they have been ongoing and we've heard about those for many years. The province have said if we continue to use Holyrood, we are to put emission controls on that plant.

MR. JOHNSON:

Q. Do we know whether - I know there is a statement in the Energy Plan to that effect and that's, I guess, provincial policy. Do we know, you know, from a cost benefit point of view how that would compete with just going all out and buying a lower sulphur content fuel?

MR. HUMPHRIES:

Q. Paul Humphries. I'll take that. Yes, we do -

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from the point of the analysis of the actual elimination or converting to a new technology earlier than the anticipated retirement of Holyrood, is it cost effective, barring any further sanctions on emissions, to continue to operate Holyrood until its normal retirement time.

MR. JOHNSON:

Q. Can I change gears a little bit and start talking about the HVDC overhead transmission line, and I understand from the record, MHI 71, that this design, the detail design is underway by SNC Lavalin, is that correct?

MR. HUMPHRIES:

A. Yes.

MR. JOHNSON:

Q. And it was supposed to be completed before 2012. What's the status of the design on that line?

MR. HARRINGTON:

A. The engineering is ongoing with regards to the design of that line. You know, there's a significant amount of work there to put it all together, and we are putting technical specifications together for converted stations

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and verifying that with our system planning group to make sure all of those design concepts are interlocked and we're going to get the best design possible.

MR. JOHNSON:

Q. How would you compare what you knew about the design of the overland transmission line, DG 2, versus to what these designers know now in terms of project definition and scope, costing, and things like that?

MR. KEAN:

A. Yes, with the engagement of SNC Lavalin, and a focused experienced transmission group as part of that team, there's been a considerable amount of effort expended to define the structures, to confirm the meteorological loading and to look at designing the tower families that are required for the transmission line. So now we would have structural drawings for the transmission line in various states of revision. We would have looked at the overall tower locations through the right of way selection between Muskrat Falls and Soldiers Pond. So we've seen a considerable amount of advancement in defining

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the number of towers, the tower foundation types, the size of those towers and the locations.

MR. JOHNSON:

Q. MHI has indicated that their assessment is that Nalcor's estimate of 400 million dollars to construct this overland transmission line - well, first of all, they say it's considered DG 2 capital cost estimate, falling inside a typical range of capital construction estimates for this type of length of transmission line, but as you're aware, they say that Nalcor's estimate appears to be at the low end of the range, and they say that they have - they make, I guess, this judgment by referring to industry benchmarks as a comparison. That's what they say that they looked at, and so before I get you to comment on what you think of that, the opening of it, I'd like to find out how is it that you guys at Nalcor established your DG 2 estimate for the overland transmission line?

MR. KEAN:

A. The process of establishing the DG 2 estimate for the transmission line is founded in the

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work that we did for the line from Gull Island to Soldiers Pond in terms of the overall components of the estimate. There was a slide shown earlier and perhaps we can - it talks about the four inputs of the estimate. It's used in the slide presentation. I don't know the number. Maybe if you could pull up that presentation. It's near the back end of the - just so I could use that to speak to, DG 3 estimate preparation. 60 or 61 - go back, 58 maybe. 56, sorry. This is the correct slide. Okay, have you got that?

MR. JOHNSON:

Q. Okay.

MR. KEAN:

A. So the process for establishing the DG 2 estimate for the overland transmission basically followed the same process in the context of there were four main inputs to the estimate, and the information for those inputs was collected over a period of time. It involved, you know, some of the - it built upon the work we had done for the Gull Island to Soldiers Pond transmission line, in which case we had done detailed field investigations

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over the right of way for the line routing. We had engaged a company called RSW to conduct a number of detailed studies, as well as work with us to develop a detailed cost estimate. That base material was used along with various pieces of market data for transmission steel cost, dollars per kilogram, for instance, for transmission towers, the cost for insulators, the cost for conductors, and so on, so there was a number of budgetary quotes sought from the marketplace and we used the bottom up estimate to work out an appropriate estimate for the current line that we have for the 320 kilovolt line that extends from Muskrat Falls through to Soldiers Pond. So it was somewhat of a reverse engineering, and then going from bottom up again to validate that it worked and that the numbers were well founded.

MR. JOHNSON:

Q. Just explain bottom up for a second?

MR. KEAN:

A. Certainly. So when I use the word "bottom up", I guess, or first principles, it is looking at all the various elements that factor into a cost estimate, i.e., what is it

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you have to build, the number of towers you need to erect, what does it take to erect the tower, and you have to prepare a foundation, what goes into the foundation, what type of equipment is required, what type of labour is required. So you look at all the lowest level of detail in terms of those elements to understand how they come together to facilitate the erection of that tower. So that's a principle bottom up estimate versus a top down where it would be more of a scaled. So we worked with bottom up.

MR. JOHNSON:

Q. More of a scaled, what did you mean by that?

MR. KEAN:

A. I guess a term often used in industry at a Class 5 estimate is a parametric based estimate whereby transmission cost "x" number of thousand dollars per kilometre, and you say, well, based upon my line, I think it's going to cost me "x" thousand dollars per kilometre. You can do that as a good process to benchmark, but it's always good to get right down into the detail, you know, so that gives you a sound foundation to understand

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your uncertainties.

MR. JOHNSON:

Q. Do you - I guess you would be familiar with industry benchmarks then regarding the cost of such lines, but that's not what you used for DG 2, I think is what you're saying me.

MR. KEAN:

A. Yes, that is correct.

MR. JOHNSON:

Q. Okay, and the - so in terms of MHI remarking that you're at the low end of the range, are you familiar with the range that they might be referring to, or where that range comes from?

MR. KEAN:

A. No, I'm not particularly familiar with the comment or the aspect of range in the context of what range it is. I would assume it would be a Class 5 range, if you would, that they're referring to, that -50, +30 again, - 30, +50 again.

MR. JOHNSON:

Q. No, no, they - what they were indicating is that in their view the Nalcor estimate appeared to be at the low end of the range of referring to the use of benchmarks that they

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had a look at.
MR. KEAN:
A. Okay, so it would be on the - I would assume in that regard, would be on the range of the benchmarks.
MR. JOHNSON:
Q. Okay, but you're not familiar with the -
MR. KEAN:
A. I'm not familiar with the particular benchmarks that Manitoba Hydro would have used, but we do appreciate their insights and we are undergoing a process now to confirm the design, to gather all the key data that is required in terms of pricing for tower steel. We just received a Request for Proposal Response for tower steel, for instance. So we will have the quality of information, and we've done extensive amount of work in the construction planning and execution in terms of how to best build the line, how much right of way clearing we need to do, and so on. So all that will come together in DG 3, as per Slide 56, to give us clarity as what constitutes a solid base estimate with great levels of confidence.

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MR. JOHNSON:
Q. So, I guess, just to make sure I understand it, you're aware of what MHI says about being at the low end of the range, but am I right that you really can't take disagreement with them because you don't know the range that they're referring to?
MR. KEAN:
A. Yes, that is correct.
MR. JOHNSON:
Q. Okay. If you took that top down thing - you know, they used to say asphalt was a million dollars a mile or something, you know. If you took it from a top down - and that's probably a good while ago, but from a top down point of view, if you said 1100 kilometres of HVDC transmission line all over there, do you have a sense of what we would be talking about on a per kilometre basis, you know, what these benchmarks out there might say?
MR. KEAN:
A. I can't - I really don't know. What I do know is that I spent a lot of my career looking at benchmarks for various facilities, and what I can say is that benchmarks, you need to really

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get into the details of what's included and what's not included to have a true comparison.
MR. JOHNSON:
Q. Okay. Then we also have the issue, which I suppose is a cost issue as well, but it's a cost that falls out of design loading criteria or, you know, the 1 in 50, the 1 in 150, that type of thing, and the Board's independent consultants made a finding in a report, that Nalcor's aware of, that the 1 in 50 year reliability return period is inconsistent with a recommended 1 in 500 year reliability return period outlined in the international standard for this class of line without an alternate supply, and in the case where there is an alternate supply, they say that the 1 and 150 reliability return period is acceptable. Now first of all, explain for us the 1 in 150, what does that mean to someone, a 2 percent chance per year that something happens?
MR. KEAN:
A. Well, 1 in 50 would be a 2 percent chance of failure; 1 in 150 is 1/150th, which would be .16 percent.
MR. JOHNSON:

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Q. And failure would be caused by weather events, is that what we're talking about?
MR. KEAN:
A. Generally in our environment, yes, it would be a weather related event.
MR. JOHNSON:
Q. So they talk about, like, a 50 year storm, a 100 year storm, that's a storm - a 50 year storm is a storm that has a 2 percent chance of occurring every year, would that be -
MR. KEAN:
A. Yes, there's a 2 percent probability.
MR. JOHNSON:
Q. So if it's a 1 in 50 year design, would it withstand that particular storm or would it falter under that type of storm?
MR. KEAN:
A. Under the 1 in 50 year?
MR. JOHNSON:
Q. Yeah.
MR. KEAN:
A. In theory, it should stand.
MR. JOHNSON:
Q. Okay, but if it's more intense and severe -
MR. KEAN:

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A. It could fail.
MR. JOHNSON:
Q. It could fail, and you've got a long transmission line of 1100 kilometres, and Newfoundland is a big island and different weather conditions and meteorological conditions presumably all the way along, where do - how do we assess what a 1 in 50 year storm is? Like, is there one storm event or weather related event that we're assuming that would be applicable to the whole area, how does that work?
MR. KEAN:
A. No, we would basically look at the climatological patterns along the whole length of the line and they are different in different regions, you know, and the extreme case as we spoke of earlier would probably be on the Long Range Mountains. We know we have an extreme ice load on the Avalon Peninsula. There's other areas where icing is not as significant. We would divide the line into segments and the 1 in 50 year design, or the 1 in 150 year design, for those particular areas would be different based on those anticipated

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loadings.
MR. JOHNSON:
Q. Okay. So would that mean then in terms of looking at the physical line for the course of the 1100 kilometres, are we looking at different configurations and strength as we go in different areas?
MR. KEAN:
A. That's correct, we would.
MR. JOHNSON:
Q. So for Avalon ice loading, that's going to look different than a place where the meteorological conditions are not known to be so severe based on - what is it, historical records?
MR. KEAN:
A. Yes, that's correct.
MR. JOHNSON:
Q. And how far back do your records go? Do you have equally quality data over the length of this line or are some areas better than others?
MR. KEAN:
A. Some areas are better than others, but we have been monitoring the path, and also we have our

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experience of existing lines in areas that would be common.
MR. JOHNSON:
Q. Who's right on the issue of whether or not an international standard is being met, because, you know, MHI seem to say, you know, this is what the standard says, you know, 500, you know, if you don't have alternate, you got to be 500, and if you do have alternate available power, you can be 150, but as I understand it, you're saying, no, we meet the standard by being 1 in 50, and I'm just wondering can both of you be right?
MR. KEAN:
A. It's possible we both could be right. We have assessed the standard and looked at the recommendations that minimum design should be 1 in 50, and then there are conditions were it's suggested it be a higher designer, whether it be 1 in 150 or 1 in 500, and then we've taken that and looked at that line and looked at it in the situation of our system, and looked at it from the perspective of providing an acceptable level of reliability to our customers, what is our best approach.

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Reliability is very important to us, always has been, but also cost is as well.
MR. JOHNSON:
Q. Yes.
MR. KEAN:
A. And we try to do and ensure that we are placing our reliability dollars in the proper place, so that we're not overcharging our customers. From the perspective of the island system and the loss of the link from Labrador, we've come to the conclusion that we need to make a balance between the reliability of the line and the level of backup generation that's available to support the load in the event the line goes out of service.
MR. JOHNSON:
Q. As at DG 2, are you describing a line that for the whole course is 1 in 50?
MR. KEAN:
A. 1 in 50, yes.
MR. JOHNSON:
Q. And if it's in Daniel's Harbour, that 1 in 50 could mean something - I'm making that up now, but somewhere it could mean something else.
MR. KEAN:

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A. Yes.
MR. JOHNSON:
Q. So that's what we're talking about as of DG 2?
MR. KEAN:
A. That's what we're talking about.
MR. JOHNSON:
Q. Okay. Are you - is Nalcor fitting within some sort of tolerance within these international standards that allows you to add small pockets of thermal generation as a means of not having to comply with the 1 in 150 standard? Is that how it works?
MR. KEAN:
A. Well, it comes down to a balance of what is right and what limits the impact to your customer.
MR. JOHNSON:
Q. And, I guess -
MR. KEAN:
A. In our view and in our interpretation of the standard.
MR. JOHNSON:
Q. So there is a difference in interpretation in the standard?
MR. KEAN:

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A. I'm not sure if there is.
MR. JOHNSON:
Q. I understand, in any event, that beefing up the line to 1 in 150 year return period adds 150 million dollars to the cost of the transmission line. I think that's a figure that came out of an RFI. Are we on the same -
MR. KEAN:
A. Yes, that's right.
MR. JOHNSON:
Q. And if we went further and said, you know, 1 in 500, what would be the incremental cost versus your existing DG 2 design?
MR. KEAN:
A. I don't have that number right now.
MR. JOHNSON:
Q. Okay. Is it a number that you would have available over at Nalcor or somewhere?
MR. KEAN:
A. I think we should be able to, yes.
MR. JOHNSON:
Q. I think it would be useful to have it for the record just to see what the number is. I understand the idea that extra reliability costs more money, and getting that last bit of

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reliability is the most expensive part, I suppose, you know, to rule out all possibilities, but I want to try to understand for the customer how your approach to adding on some small generation where need be is to the customer's advantage as opposed to spending the money on beefing up the line to 1 in 150?
MR. KEAN:
A. Well, in the event we beef the line up to 1 in 150, that line can still fail. The probability is lower, but it can still fail. When the line goes out, it doesn't matter whether the design was 1 in 50, 1 in 150, or 1 in 500, the line is out of service, and the customer is conceivably without power. So from the perspective of the balance between adding generation on the island, what the generation on the island does is basically reduce the reliance on the link for supply. So in the event the line fails, the customer left without the line is in a better position, we have more generation to serve the load, so the impact on the customer is less.
MR. JOHNSON:

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Q. So just give us, if you could, like, a concrete illustration of where, for instance, you might put an extra small thermal generator? You know, it's hypothetical, but some insight in how that would be a benefit?
MR. KEAN:
A. More than likely we would establish it somewhere on the Avalon Peninsula because that is where our load centre is, but it could be anywhere on the island. We have them here in the St. John's area now, we have one at Stephenville, the Holyrood site, we might establish them there, they could be anywhere on the island actually, but more than likely we would choose a site on the Avalon Peninsula.
MR. JOHNSON:
Q. As I understand it as well, Nalcor -- according to MHI's report, Nalcor has said if we spend the money and bring it up to one in 150, if we have an event that knocks out the line, that line is gone and the rest of our system is not built to one and 150 anyhow and as I understand it, you know, you're saying what are we accomplishing by having the robust

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-- the more robust 1100 kilometre line when the rest of the line infrastructure would fail in any event under that type of circumstance? More or less have I got what your position is?

MR. HUMPHRIES:

A. Yeah, and that applies if the storm is in an area where we have common transmission, like on the Avalon Peninsula, for argument sake. If there were that level of an event on the Avalon Peninsula, there's a very high probability that the link would remain standing and the supporting 230 kV transmission that supplies the local load would be flat.

MR. JOHNSON:

Q. And so is there no -- there's no line on the island, I take it, that is in excess of the one and 50 year return at this point?

MR. HUMPHRIES:

A. That's correct.

MR. JOHNSON:

Q. And how old is the newest transmission line?

MR. HUMPHRIES:

A. The newest one would probably be seven years old.

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MR. JOHNSON:

Q. How old?

MR. HUMPHRIES:

A. Seven years.

MR. JOHNSON:

Q. And where does that line run?

MR. HUMPHRIES:

A. That's the line that supplies -- it connects Granite Canal to the grid.

MR. JOHNSON:

Q. I had a question put to me by a gentleman here earlier who wanted me to raise with you, you know, the possibility of a Montreal ice storm and I think he was getting at, you know, the lessons from the Montreal ice storm where there was outages for a considerable period of time and my understanding is following that, they had a different look at, you know, what the return period should be and the design criteria, loading criteria, and can you comment on that aspect? It's a fairly recent example. Dramatic, but recent.

MR. HUMPHRIES:

A. Yeah, and they are -- that is an issue and there's no doubt that there are critical

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transmission lines out there that may be the sole source of supply and that if they come down, everyone is without power and it makes sense to invest more in these lines to increase reliability and reduce the probability of these risks. In lots of cases when these storms happen, the bulk transmission remains standing. There's still severe power outages because of downed under distribution lines and lower voltage supply lines. So, it's a mixed bag from that perspective.

MR. JOHNSON:

Q. Did they adopt a higher standard in Quebec after the storm?

MR. HUMPHRIES:

A. For their major lines, yes, they have.

MR. JOHNSON:

Q. To one in 500, was it? Is that -- did they go that far?

MR. HUMPHRIES:

A. I think they're at one in 500, yes.

MR. JOHNSON:

Q. I guess a question related to the Labrador-Island link is a question of a cable failure

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and a gentleman in Carbonear, Mr. Graham Moores, said that I could use his name, so I'll use it, and he wished to know if there were to be a cable failure for the Strait of Belle Isle, what would be the plan and how long would it be to fix it?

MR. HUMPHRIES:

A. Well, if there were -- to begin with, there will be spare cable on the link so that if we have a single cable loss, it's business as usual. From the perspective of the repair of a damaged cable, that could take up to six months to repair a damaged cable.

MR. JOHNSON:

Q. Coming back then to the transmission line, say what's the part of our geography in Newfoundland where this line is going to run through that has the Nalcor, the Hydro people the most concerned?

MR. HUMPHRIES:

A. Well obviously the main area of concern is the crossing of the Long Range Mountains. You know, that's new terrain. We've done a lot of study on it, but we have no transmission in that area at this time. And again, the Avalon

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Peninsula, we've had a history of icing events on the Avalon Peninsula and we've beefed up our line designs considerably in recent history to mitigate those outages.

MR. JOHNSON:

Q. Did you -- but you didn't beef them up beyond a one in 50, I take it?

MR. HUMPHRIES:

A. No, in fact they're only at one in 25.

MR. JOHNSON:

Q. Okay. And how did you beef them up?

MR. HUMPHRIES:

A. We actually -- we changed out conductors, put in midspan structures to strengthen the line. We put in anti-cascading structures so that if we have a failure to limit the amount of damage, that we would lose fewer spans and those types of things.

MR. JOHNSON:

Q. Yeah, that's -- I guess I should have probably asked that question. What does it mean -- let's say, let's take the Avalon situation and we know what a one and 50 year storm is and we know what sort of configuration you have for that and then we'll say, okay, now we're going

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to have a design for a one in 150 year event for that section of the Avalon. Sort of explain to me how it might look differently in terms of the beefing up. More towers? More steel?

MR. HUMPHRIES:

A. The spans could be shorter. The towers would be heavier, heavier steel. The conductors would be stronger. You know, it would have a general overall different appearance.

MR. JOHNSON:

Q. The same gentleman also wanted me to ask you a question and he asked if the transmission line goes down, and I take it he's referring to the HVDC, goes down and we can't access power from Muskrat Falls, is Nalcor planning to have backup generation on the island on account of the fact that the plan is to retire Holyrood as a generating facility? I think the record would indicate in Exhibit 106 that there's no plan for backup, but I'd like for you to discuss that.

MR. HUMPHRIES:

A. Yeah, well, again, I think we need to go back and consider the overall scheme that we're

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looking at. We are confident and hopeful -- or it's hopeful that the Maritime link will progress after Muskrat Falls and we will have a second connection to the North American grid via Nova Scotia. That will be a bi-directional connection meaning that power can flow in either direction. So, that will be a great benefit to mitigate the risk of the loss of the Labrador link and it would cover off -- give us the ability to cover off the loss. So in effect, that would be a backup source of generation.

MR. JOHNSON:

Q. And I guess that leads me to a question I think I got over the weekend from a gentleman and I think I filed it this morning or asked my office to file it, and that is whether or not this proposal, Muskrat Labrador link, depends upon successful conclusion of the Maritime link and that was, I think, the gentleman's question.

MR. HUMPHRIES:

A. And my answer is no, it doesn't.

MR. JOHNSON:

Q. While I have these questions, there was some -

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- I'll put them now. They don't particularly tie into what I've been -- we've been discussing thus far, but I have a question that arises out of -- from a gentleman that arises out of the presentation this morning that said that by going with the Muskrat Falls option, we are going to be, in relatively short order, largely clean energy as opposed to 35 percent thermal now, roundabout, but the individual pointed out, well at 2067, we're all 35 percent thermal at that stage, so you know, what are -- I guess the implication is, you know, you're planning to bring us back to 35 percent thermal by 2067. What's the answer to that concern?

MR. BENNETT:

A. It's Gilbert Bennett. Our answer is a distinction between capacity and energy on the system and there will be thermal capacity on the system, but it's only used when the system is under peak loading. So, the amount of energy produced by that thermal generation is very small. There are two places we can look at that. The pie chart that I had this morning in the presentation with the CPW

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breakdown, if you pull that one up, if everybody can bear with me for a moment, please. So on page 33, the fuel bill post 2017 is a very small sliver that's extended out of the pie and it's .4 percent of our CPW.

MR. JOHNSON:

Q. Okay.

MR. BENNETT:

A. Very small amount of fuel that's burned from that thermal generation.

MR. JOHNSON:

Q. So the thermal we have at that point is for peaking purposes?

MR. BENNETT:

A. That's right.

MR. JOHNSON:

Q. Not to be used very much?

MR. BENNETT:

A. That's right, and I think if we refer to Exhibit 99, we can see the fuel expenditures in there and there's a stark difference between the two, the two plans in the latter years.

MR. JOHNSON:

Q. Exhibit 99.

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MR. BENNETT:

A. So if we go right to the last page of this spreadsheet, the fuel expense in the Interconnected scenario is actually right here on -- you can see under the heading, the red heading, total fuel expense, there were four rows underneath there and if you go over to 2067 on the bottom row, that's the total amount of fuel burned or forecasted to be burned in the Interconnected scenario. That's 176,000 barrels.

MR. JOHNSON:

Q. Okay.

MR. BENNETT:

A. So, very small amount.

MR. JOHNSON:

Q. Okay. Yeah, okay.

MR. BENNETT:

A. I think just for reference, the equivalent number in the Isolated scenario is about 6.1 million barrels.

MR. JOHNSON:

Q. Yes, okay. Question sort of having to do with the addition of Portland Creek. I think Portland Creek would be an addition that would

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be contemplated under the Muskrat Falls Labrador-Island link scenario and the question was what would be the purpose of building the Portland Creek hydro facility? Is it for peaking use or is it for energy?

MR. BENNETT:

A. The predominant driver is for peaking capacity, but when we look at Portland Creek, Portland Creek is a very attractive hydro site. It has a competitive price, so when the strategists program was looking at the resources available, we had a capacity deficit, but because the energy price was also attractive, it was chosen to fill a double bill.

MR. JOHNSON:

Q. So, did the attractiveness of the energy have anything to do with water flows during the critical heating period with Portland Creek? You know, some -- as I understand it, some small hydro, they don't have water when you need it and they got water when you don't need it, you know, May-June type of idea. How does Portland Creek profile?

MR. BENNETT:

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A. We would have the ability to be able to access peak capacity at Portland Creek.

MR. JOHNSON:

Q. Okay, yeah, and also, this individual indicated to me that isn't this also a major salmon river, Portland Creek? I guess it's one of the few that I haven't fished, I suppose.

MR. BENNETT:

A. We have done the environmental screening on Portland Creek. We've had feasibility studies completed and we don't anticipate it being a significant environmental issue.

MR. JOHNSON:

Q. On the topic of Portland Creek, because while the Portland Creek shows up in the Muskrat Falls Labrador-Island link scenario, it also obviously figures prominently in the Isolated scenario and that along with Island Pond and thermal and et cetera, and in terms of -- as your presentation indicated this morning that the bulk of the bucks being spent in the island Isolated scenario is oil, but there's obviously capital costs associated with not only remediation at Holyrood, but building

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these hydro electric facilities as well. In terms of the numbers on the hydroelectric capital additions, how old are these numbers? How solid are these numbers? Are they conservative?

MR. BENNETT:

A. The Island Pond and Portland Creek are based on studies that were completed in the early to mid 2000 time frame and have been updated regularly to reflect current trends in the industry. The actual Round Pond estimate is more dated, but it has been updated, but on a -- based on current escalation indices, but it hasn't been reviewed in detail since -- in a number of years.

MR. JOHNSON:

Q. A question also put to me was what is the current status of decision making regarding the Federal loan guarantee for the project? Is that a question that anybody can answer on this panel?

MR. HUMPHRIES:

A. I think all I can say is that discussions with the Government of Canada are ongoing.

MR. JOHNSON:

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Q. A question also was the Government of Canada commitment at at least one point had been put in terms of a Federal loan guarantee or the financial equivalent and the questioner was interested in knowing whether the financial equivalent would be to have the Federal government, in essence, be in the exact same position as they would be had they provided a guarantee and there was a default. In other words, I think the implication of the question was, to this person's thinking, that if the Federal government guarantee is worth 600 million dollars in 2010 dollars, according to your sensitivity test, getting a cheque from the Federal Government for 600 million is not the same as having them give a guarantee and he was interested in knowing if there was any thoughts on that concern.

O'REILLY, Q.C.:

Q. Mr. Chairman, I don't know how this is helping us. I mean, I can understand that this is a part of the equation and it's been out there that there has been, you know, negotiation as a part of it, it might affect the status of negotiations on the progress of the project

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and so on, but the nature and extent of negotiations between the Government of Canada and say the Province or whatever, I don't know how that is really helpful to inform this process. I'm having some difficulty in that.

CHAIRMAN:

Q. What have you got to say for yourself?

O'REILLY, Q,C.:

Q. Put his credit card on the table.

MR. JOHNSON:

Q. I asked the person's question and I realize issues between government to government negotiations are not something that Nalcor can be expected to speak too much in detail about, I would think, but in fairness to the gentleman, I put the question there.

CHAIRMAN:

Q. Put the question in the record.

MR. JOHNSON:

Q. Yeah, I put the question on the record.

CHAIRMAN:

Q. What do you think, Madame?

GREENE, Q.C.:

Q. I guess one of the challenges for all of us is interpreting the Terms of Reference and the

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mandate question. There have been instances, for example, the Maritime link has been excluded from review, but yet there have been references to it with respect to reliability. So I guess it would be a challenge for all of us as we move forward to stay within the mandate. The issue of the loan guarantee was not included and was excluded from the reference before the Board.

MR. JOHNSON:

Q. Turning then to the -

CHAIRMAN:

Q. I mean, would it have any effect on the final cost, I guess is the question. Would it affect this two billion dollar difference?

MR. JOHNSON:

Q. It certainly will affect the 2.2 billion as pointed out in the sensitivity and I think from what I understand unless something is more certain -- if something is less than certain, it's used as a sensitivity. I think that's the approach that's been taken in the materials. But certainly for the purpose of the sensitivity, there's a dollar figure on it.

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The issue of the integration studies, the AC integration studies, I'd like to try to address that. As I understand it -- well, why don't we just start bottom up. The integration study is aimed at finding out what?

MR. HUMPHRIES:

A. It's aimed at looking at and identifying issues with the integration of the Muskrat Falls and Labrador-Island link with the Island system, operational type issues.

MR. JOHNSON:

Q. And what are the operational type issues?

MR. HUMPHRIES:

A. Well, there may be equipment, for argument sake, that would need upgrading because of the integration of the project. There may -- how the system is going to react to contingencies, being outages, be they trips of transmission lines on the island or loss of link, those types of things and ensure that the system operates in an orderly fashion.

MR. JOHNSON:

Q. And just could you give us some examples of, you know, problems that may have to be

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overcome and how you would overcome them through the suggestions in an integration study?

MR. HUMPHRIES:

A. Well, one obvious thing that's come out from previous studies that as we integrate the link and we add all this additional synchronous condenser capability at Soldier's Pond, that basically increases the strength or the fault level of the system and there's a number of circuit breakers in the system that are -- existing circuit breakers that are no longer adequate and they have to be changed out because of this increased fault level.

MR. JOHNSON:

Q. And is that something that's been costed in DG2?

MR. HUMPHRIES:

A. Yes, it is.

MR. JOHNSON:

Q. And who is completing the integration studies? Are they being completed in house?

MR. HUMPHRIES:

A. No, they're being completed by SNC.

MR. JOHNSON:

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Q. Okay. And they have -- Manitoba Hydro International, of course, has identified the integration study issue as a gap that they indicate they would have expected to be completed as part of the project screening process at DG2 and I'd like your assessment as to whether is this a gap or not a gap or what's Nalcor's position on it?

MR. HUMPHRIES:

A. Well, I'll first fill you in and tell you what we've done and what we've assumed. If you look back over the history of the integration of a DC link into the island of Newfoundland, we've been looking at it for a number of years and there have been a number of varying integration studies on different schemes, as was indicated in the MHI report. The most recent of those would have been in 1998 when we looked at the integration of a bi-pole point-to-point HVDC link from Gull Island to Soldier's Pond. There was an extensive integration study done on that configuration. And in the 2007 time frame, we also completed an integration study based on another arrangement which was a 1600 megawatt larger

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arrangement. It was what you call a multi-terminal and which there was a link to New Brunswick. We have the results of those studies. We are of the opinion that the 1998 scheme is very similar to what we are looking at today and further, we compared the results of the integration study from '98 with the 2007 and from the perspective of the integration impacts into the island system, they're practically identical. There were -- the differences were insignificant.

MR. JOHNSON:

Q. Could I stop you there for a second, Mr. Humphries, and what were the things that you were finding practically identical?

MR. HUMPHRIES:

A. Well, the circuit breakers that I spoke of earlier that needed to be upgraded, they were the same. The overload conditions we may have had on transmission lines were the same. The system performance for various contingencies, that be line trips or generator trips, were practically the same. Actually, more than practically, they were the same.

MR. JOHNSON:

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Q. And so that was the knowledge that was used by Nalcor in terms of coming up with the features -

MR. HUMPHRIES:

A. For DG2.

MR. JOHNSON:

Q. - for project definition for the system to successfully integrate the power coming down from Muskrat?

MR. HUMPHRIES:

A. Yes.

MR. JOHNSON:

Q. And you're telling me that got costed in?

MR. HUMPHRIES:

A. All those items are costed in, yes, to the DG2 basis of design.

MR. JOHNSON:

Q. Okay. And when you say all those items got costed in, would that have contemplated costing in any backup generation or beefed up lines?

MR. HUMPHRIES:

A. No, the system integration does not address system reliability issues.

MR. JOHNSON:

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Q. Okay. So the items then, can you be specific about what got costed in at DG2 as a result of where your analysis had led you to on the integration needs?

MR. HUMPHRIES:

A. We costed in three additional synchronous condensers at the Soldier's Pond converter station. There were a number of circuit breaker upgrades that were identified. And those are the bulk of the items that are in the plan right now.

MR. JOHNSON:

Q. And I take it your presentation indicates that as a result Nalcor had sufficient input data to move through DG2 with the intention of completing the full integration studies for DG3?

MR. HUMPHRIES:

A. That's correct.

MR. JOHNSON:

Q. So that's the one that are still ongoing. I do have to ask you a question though. The bullet point before that said "analysis determined point-to-point link will have similar characteristics regardless of change

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in generation source provided there is a line to Churchill Falls," and how did the AC line to Churchill Falls figure into that?

MR. HUMPHRIES:

A. Well, basically, with a strong connection back to Churchill Falls, Churchill Falls is the dominating force in Labrador from the perspective and whether the generation source at the converter location, whether it be Muskrat Falls or Gull Island, is not significant in the overall performance.

MR. JOHNSON:

Q. Okay.

CHAIRMAN:

Q. Does anybody feel inclined to a break? I'll speak for myself, I don't, but -

MR. JOHNSON:

Q. No.

CHAIRMAN:

Q. - somebody asked me whether -- but I mean, I'll defer to the - I don't -

MR. JOHNSON:

Q. I don't require one.

COMMISSIONER:

Q. What about the panel?

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CHAIRMAN:

Q. How are you guys?

MR. BENNETT:

A. I think we're okay.

MR. HUMPHRIES:

A. We're okay.

CHAIRMAN:

Q. Well, let's keep her going.

MR. JOHNSON:

Q. I'm now in trouble. Someone wanted one, didn't they?

CHAIRMAN:

Q. Does anybody want a break?

VICE-CHAIR WHALEN:

Q. Hearing none.

CHAIRMAN:

Q. Carry on.

MR. JOHNSON:

Q. Okay. Bringing it -- you know, all these things obviously are important from my point of view in terms of looking at the costs, right, and I'd just like to get your comment on MHI says that there may be additional risk factors that may impact cumulative present worth of the in-feed option. That was their

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conclusion based -- you know, you're all familiar with the AC integration comments, and so, you know, I would be worried if there was something there that we don't know about as of DG2 and I'd like you to address that. You know, is there a known unknown or an unknown unknown?

MR. HUMPHRIES:

A. Based on -- it's our view, based on our understanding of our system and the previous studies, that the items identified in these studies were representative of what we would be faced with with the integration of the Muskrat Falls scenario and further to that, the studies, the current studies are ongoing and while they're not complete yet, we have seen some preliminary results or indication -- I haven't seen them, but I've talked to -- some of my staff are participating and we have not identified it and don't expect to.

MR. JOHNSON:

Q. MHI refers specifically, and I'm not taking away from your answer, but they refer specifically to possibilities such as installation of backup supplies to cover

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operational limitations in the Labrador-Island link system maybe required and additional transmission lines may be needed or spare equipment, and I guess I'd be interested in knowing are those the type of things that you could get into at the stage that -- at DG3?

MR. HUMPHRIES:

A. We don't think so, no. We don't think we would get into those.

MR. JOHNSON:

Q. The other issue regarding system reliability had to do with probabilistic modelling and everything. Now I understand that in your presentation this morning, you've indicated that Nalcor is implementing a more advanced and comprehensive reliability model that incorporates all components of the Labrador-Island link HVDC system for DG3. However, I'm interested in knowing, as at DG2, the numbers we have, are there any cost implications that we are not aware of or not on the record that may be -- that may grow out of DG3 efforts as relation -- in relation to the system reliability piece?

MR. HUMPHRIES:

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A. No, I do not think so. The probabilistic model that we're speaking of that we're developing is a refinement of -- well, the result and a refinement of the forced outage rate for the Labrador-Island link which Manitoba Hydro has already commented the number we're using appears to be in an acceptable range. So I don't expect any issue.

MR. JOHNSON:

Q. I've got two questions. The number that you're using is .89 percent.

MR. HUMPHRIES:

A. Yes.

MR. JOHNSON:

Q. On a per pole basis, and I understand the presentation this morning indicated that was an assumed figure?

MR. HUMPHRIES:

A. It was based on a previous probabilistic assessment of a similar arrangement, yes.

MR. JOHNSON:

Q. And MHI, and I just want to see where the points, if any, of disagreement are. MHI, I believe, going on memory, said that they

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accepted .89 percent as being, you know, a decent value, didn't quibble with that, but found that in the information that they had seen, they couldn't determine that number on their own. They couldn't, I guess, validate the number. Is that a fair comment from MHI?

MR. HUMPHRIES:

A. Yeah. We've accepted that and the work that we're currently carrying out will address and the model will be specific to the scheme we're looking at today.

MR. JOHNSON:

Q. I'd like to turn to system upgrades pertaining to the Muskrat Falls Labrador-Island link scenario and I believe that's a 194 million dollar component to the scenario and first of all, what are we talking about in terms of system upgrades? What falls under that?

MR. HUMPHRIES:

A. These are the items that we identified previously. I spoke of the synchronous condensers, the circuit breaker upgrades.

MR. JOHNSON:

Q. Okay. Now MHI indicated that they found that Nalcor's DG2 estimates for the converter

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stations and electrodes were found to be reasonable for DG2 purposes which they compare to industry benchmarks. However, at page 60, I think it's of Volume 1, they state that "Nalcor's estimates for system upgrades, including the three 300 MVA synchronous condensers, plus the conversion of the two generating units at Holyrood, as well as the addition of several high voltage breakers were low" and they said they're low but are within the bounds of cost estimate variability, and they found them to be reasonable inputs to the DG2 screening process and the CPW analysis. So I guess, first of all, how did you guys at -- or I shouldn't say you guys -- how did Nalcor, at DG2, come to put your estimate in place for these components?

MR. HUMPHRIES:

A. I'll get Mr. Kean to address that.

MR. KEAN:

A. Thank you. Yes, we appreciate Manitoba Hydro's insight in this regard. I recall having some discussion with them during the interview phase. At Decision Gate 2, for the synchronous condenser component, we looked at

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two aspects. The largest cost aspect of that is the machine itself and we went and requested budgetary quotes. The quote that we selected to use in the estimate is from Toshiba, Toshiba out of Japan. Further, we looked at the civil and site works associated with that structure. So we looked at the size of the yard, the concrete, and got some basic structural dimensions and did a review of what the cost of the civil works would be. So that's the primary basis of the DG2 estimate.

Since that time, we were doing, you know, fairly detailed layouts of that site at Soldier's Pond and verifying the machine characteristics and we're in the process -- we've actually gone out and are requesting new up-to-date budgetary quotes that we will be able to incorporate in the Decision Gate 3 estimate.

MR. JOHNSON:

Q. So as at Decision Gate 2, what was left to be done or what had to be done to get to DG 3 level? I guess what I'm getting at, in terms of putting a cost estimate in place for these system upgrades.

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MR. KEAN:

A. The DG2 estimate would have been fairly preliminary in many aspects, in particular on the civil works, as well as the associated electromechanical works for the facility. The synchronous condensers are housed in a large structure, so we would have not had, let's say, detailed drawings to support a quantity take off of concrete, nor would we have details on overhead cranes or electrical mechanical outfitting that would be required for that facility. So between -- over the last year with SNC's engagement, we've worked on defining that much further and of course, having greater clarity on the characteristics of the machine so we can go out and get further and more advanced budgetary quotes.

MR. JOHNSON:

Q. And are we expecting an increase in the cost between DG2 and DG3 or can you state?

MR. KEAN:

A. A little bit difficult to comment on the machine aspect. The DG2 was done in a Q1-2010 economic environment. We're gone out today to get new budgetary prices. That is the largest

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cost element of that, of the synchronous condensers, the machine itself. I really can't speculate until we go through the process and look at in the entire picture of the DG3 estimate.

MR. JOHNSON:

Q. MHI indicates that they -- this is, for the record, page 112 of Volume 2. They say that for the purpose of developing a cost estimate comparison, MHI used data from similar prior projects. Are you familiar with what prior projects they were referring to or have you -- did you look at other projects yourselves in terms of coming up with DG2 numbers?

MR. KEAN:

A. Yes, we did. With actual engagement of Manitoba Hydro a couple of years back and some visits that we had to Dorsey and so on.

MR. JOHNSON:

Q. Okay.

MR. KEAN:

A. So we did look at some of that, as well as engagement with Toshiba.

MR. JOHNSON:

Q. Okay. I'm going to put to you some concerns

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that have been raised from commentators that I've been following, monitoring commentary from citizens about Muskrat Falls and I know there's been a considerable amount of back and forth over the issues and I want to take this opportunity to put to you some concerns that have been expressed for your response in this forum as certainly some of these concerns would seem to go to the matters raised in the reference.

One concern I saw expressed in an October 8th commentary from 2011 in The Telegram was that projects like Muskrat Falls are known for cost overruns. One commentary, the commentary cited a World Commission on Dams report which according to the commentary concluded that building dams had overruns on average of 56 percent. There was also reference in the commentary to a proposed site sea dam in British Columbia which started at a three billion dollar cost estimate and on May 2011, the new price was almost eight billion dollars. And this is a concern that goes to the cost estimation and the prospect for overruns and I'd like for you to speak to that

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concern.

MR. KEAN:

A. Yes, we are aware of this phenomena. It's actually an area that I've published a couple papers on myself. Mega projects are challenging, but as we indicated in our presentation, there are some key things that one can do in planning a project of this size and magnitude that can get things going well. A key aspect of that is front end loading. Front end loading is the number one predictor of success of a mega project. So many of the things that we've been focused on throughout the last four years, four plus years, is to ensure we're well established in that regard. We've engaged independent project analysts out of Virginia to come in and assess, using their proprietary technology and proprietary methods, how well defined our project is and are we on track in terms of being for front end loading. They said we were -- at DG2, we were best in class at that point and we were on track to being in very good shape for DG3. Further, I guess the project has very well defined objectives. We know what we need

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to do. We have a team that's been together that is -- and we further have engaged a world class EPCM consultant to work with us. The plans and targets are realistic. They're based on well founded engineering and work that we've undertaken extensively over the past few years and they're achievable.

MR. JOHNSON:

Q. A question I'd have coming out of that concern would be the -- has Nalcor looked at where these other projects seemingly -- and I'm not familiar with some of them, but the horror stories are out there, but has Nalcor looked at what went on in those projects to figure out where these drivers happened?

MR. HARRINGTON:

A. Nalcor is part of the Canadian Electrical Utilities Project Management Network. That's quite a mouthful for me to say, but anyway, so we meet twice a year to go through lessons learned from different projects and, you know, we take all of those lessons learned under good advisement. We listen to what the other challenges are on different projects and you made a reference to site sea and the evolution

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of that project. Well, that project has changed significantly from that which was originally contemplated. So, those things have to be taken into account when you review how a cost estimate changes over time. In addition, I mean, if you look at site sea and compare it to the Muskrat Falls Project, just from a -- just one metric, for example, how much material you have to move. In site sea, it's over 48 million metres cubed of material and of that, over 20 million metres cubed of material has to be moved off site. Whereas Muskrat Falls is in the two, two and a half million metres cubed of material. So from a scale perspective, we're dealing with -- we're one of the best sites in North America that's never been developed before, from a hydroelectric perspective, and that was an NEB report. I can't remember exactly the year, but you know, it's still a great project. So you know, we have certain physical conditions that Mr. Bennett pointed out in one of his slides, which escapes me, but I'm sure somebody will help me out but going to it.

MR. BENNETT:

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A. 48.
MR. HARRINGTON:
A. 48. These are the things that give me comfort, right, and should give us all comfort from the fact that we're dealing with a site that has competent bedrock. It doesn't have this massive amount of overburden or clay seams that we have to remove. We have this minimal overburden to remove and dispose of. We have conditions that have been validated by site investigations going over 20 years. We have constructability aspects which are beneficial. All of the materials that we've got are sourced from site excavation. So we're not dealing with massive amounts of trucks moving backwards and forwards to get the right type of material. We have this very good material balance, so we don't have to remove 20 odd million metres cubed of material off site, and we're dealing with basically conventional concrete methods.

We go to the next slide, please. Thank you. We don't require a massive amount of additional dams and dikes. It's all in one place. If you look at Romaine or East Main

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projects, they required additional dams and dikes to be able to form the reservoir. Muskrat Falls does not require that. We also have the reliable hydrology aspect. So you know, that's another fantastic benefit for the project. We've got robust, conventional designs for all the structures. We're using conventional methods. We don't require underground. We don't require temporary diversion tunnels which also add costs. Some projects are dealing with one and a half kilometres of diversion tunnels. We've got conventional equipment. We're using the TG sets, the gates and the cranes that's been tried and tested and we're close to Happy Valley Goose Bay. We're, you know, within 20 minutes of a major facility with a airport and port.

So all of these things give us a great comfort that we believe that we understand the risks of our project. We are not complacent with regards to other projects and other mega projects that have gone off the rails. We listen to what those other mega projects had to say and we've incorporated that in our

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project execution by embracing the concept of front end loading.
MR. JOHNSON:
Q. Another concern expressed in the commentary -- and it's a bit of a different concern. I don't know who will field this one -- was that in this province, since 2006, over 85 percent of our electricity had been produced by Hydro and less than 13 percent by the Holyrood generating station with presently two percent being wind generated. The commentary further stated that Holyrood's oil consumption was 3,678,183 barrels in 2002 and in 2010, this had decreased to 1,362,373 barrels of oil; in other words, the implication I think from the concern is that we are not using Holyrood like we once were, so I think that's what the implication was. Could someone address that concern?
MR. HUMPHRIES:
A. That is true, we are not using it like we once were, but based on our forecast on a go-forward basis, we are predicting that we will be using it and using it more than we probably we ever have.

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MR. JOHNSON:
Q. I guess it gets at a bigger issue in terms of what, you know, we can talk about when we get specific into the load forecast with the drop off of the industrial load that we saw, starting with Abitibi Stephenville in 2005 and continuing on. But, so we can come back on that, the other concern raised in the commentary had to do with, was that the Holyrood generating station will be needed, even with Muskrat Falls because it is our only backup generating facility, that goes to another concern expressed earlier. The commentary went on to say that as Nalcor has stated in a recent capital plan, this is now a quote of Nalcor in its capital plan, "It is important to consider that whichever expansion plan occurs, an isolated island electrical system or interconnected to the Lower Churchill via HVDC link, Holyrood will be an integral and vital component of the electrical system for decades to come." And apparently taken from one of Nalcor's documents. What's the reply from Nalcor to that concern?
MR. HUMPHRIES:

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A. Well I think to begin to answer that question, let's go back to a point where we were earlier on this whole issue of level of backup and the critical nature of the line and the supply from Muskrat Falls. If we look at our load profile on the system and how much we really depend on that line to contribute to the overall reliability, if we look at starting in 2017, all but approximately 600 hours of the year we would be able to supply all of the requirements on the island without the link. It's not the most economic way of doing it, there's enough capacity on the island to supply the needs. So as load grows, the line becomes more significant, that peaks at just under 3,000 hours in 2036 where we would have an exposure. The other remaining 6,000 hours, if the line came out, we would still be able to supply all the requirements on the island with the existing generation that's in place. Post 2036, it tends to moderate because we do start adding capacity to the island to maintain our reliability, generation reliability level, the LOLH and that sort of moderates 2,000 hours, there's a 2,000 hour

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exposure that we would be at risk of not being able to serve all our load if we lost the lake.

MR. JOHNSON:

Q. And when would those 2,000 hours occur?

MR. HUMPHRIES:

A. Well, they're going to occur in the winter periods.

MR. JOHNSON:

Q. Yes.

MR. HUMPHRIES:

A. There's no argument about that and from the perspective then when we look at and we--as we stated earlier, to provide a level of reliability whether that be through the line or through generation to the customer, if we looked at--let's just take the 150 million dollars for argument's sake that we're going to invest in the design upright from 1 to 50, to 1 to 150, in round dollars, that could add in the range of 125 to 150 megawatts of combustion turbine generation on the island. Because that extra 150 megawatts is there, the hours of exposure that we've had, have now decreased from 2,000 down to 1,000, there's

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less risk of not being able to serve the load. And in the event that the line does fail, we're in a much better situation with the generation than we were with the line design, so from the perspective of the level of backup, we are covering off load probability events. We have to have a failure at the worse possible time to have these exposures, right.

MR. JOHNSON:

Q. The commentary also went on to state that since 2004, electricity demand is down 15 percent on the island and there has been negative electricity growth of minus two percent over the last six years, again I guess a demand observation, and I guess the implication being, well why would we do Muskrat if that's what's happening with the recent demand?

MR. BENNETT:

A. Maybe I can take that one, it's Gilbert Bennett. If we can turn to page 8 of the presentation this morning, hopefully I can put this in perspective. So on this slide here, there are two points that are noteworthy. The

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first one is that our utility load, both historically and through our forecasting period is expected to increase on a continual basis. As I pointed out this morning, notwithstanding a population decline that happened during the 1990's, this trend of increasing utility usage has continued through that period. The second noteworthy point is that during this period two pulp and paper mills in Stephenville and Grand Falls-Windsor, respectfully, shut down and we could see those drops in demand on the industrial side. In the 2014 timeframe, we can see the increase that's expected from the Vale facility in Long Harbour, so most of this fluctuation in electricity consumption has been from the industrial sector. Over this period we see continuous and expected continual increase in utility requirements over the forecast period.

MR. JOHNSON:

Q. A concern was also expressed in a commentary in the Telegram on December 17th, 2011, a concern about PIRA's oil price forecast and the commentator noted that PIRA only provided a forecast to 2025 and that for the year 2025

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onward, Nalcor's forecast is "little more than an extrapolation of PIRA's last 2020 to 2025 forecast period, combined with an estimated inflation factor." So a concern about relying on the PIRA forecast and the extrapolation, what's the reply to Nalcor about that?

MR. GOUDIE:

A. Steve Goudie. PIRA does forecast out to 2025, that's certainly true for its crude oil and its oil product slates (phonetic). Beyond 2025, what we do for our long-term calculations is to hold that price real in constant dollars, hold it constant in real dollars, I should say, sorry, so all we're adding after 2025 is a nominal inflation rate every year. We're not assuming that that price increases in real terms.

MR. JOHNSON:

Q. And would Nalcor--in Nalcor's judgment by holding it constant, except for CPI, I guess.

MR. GOUDIE:

A. Right.

MR. JOHNSON:

Q. In Nalcor's judgment is that conservative or is it--is that conservative or -

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MR. GOUDIE:

A. Yes, that's conservative. If you look at the average annual compound growth rate of the nominal prices during their forecast period, that would range between three and a half and four and a half percent. I believe that was in Gilbert's presentation this morning.

MR. JOHNSON:

Q. I think there was reference as well to MHI did a little, sort of test, if you will, around one percent either way on the inflation.

MR. GOUDIE:

A. They did and their results indicated that there wasn't a material difference in the preference for the Interconnected Island case as a result of that assumption.

MR. JOHNSON:

Q. How long has Nalcor been using PIRA?

MR. GOUDIE:

A. We have been using PIRA since 1998 actually.

MR. JOHNSON:

Q. And they only forecast out for a certain period of time, that's as much as they'll forecast out, I think.

MR. GOUDIE:

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A. That's correct.

MR. JOHNSON:

Q. In the same commentary the writer expresses a concern as follows: "Furthermore, Canada's own national energy board in its Canada's energy future, energy supply and demand projections to 2035, November 2011"--that's how it's described, this is the report, I guess they issued on November, 2011, they say that "The NEB also forecast oil prices, but only out to the year 2035. For the year 2035, the NEB forecasts that oil prices will only be about one half of Nalcor's most recent year, 2035 forecasts." And I want to put that concern to you to address.

MR. GOUDIE:

A. I haven't seen the NEB numbers exactly and I'm not sure specifically what your reference is, but what it sounds like to me is that the NEB has a constant dollar forecast that they're presenting in their reports, and what you would see in our exhibits would be nominal dollar forecasts, inclusive of inflation; whereas the NEB may be reporting their long-run crude price, excluding inflation.

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MR. JOHNSON:

Q. Okay, and maybe if you could confirm that, I think the NEB material is in one of your exhibits that were filed recently, so it might be useful to have some definitiveness on that issue.

O'REILLY, Q.C.:

Q. So the question is, is there a different formula for reporting in on the NEB forecast prices for oil, as opposed to what Nalcor uses?

MR. GOUDIE:

A. Well essentially the question is whether NEB who is using inflation adjusted prices.

O'REILLY, Q.C.:

Q. The same as Nalcor's, okay.

MR. GOUDIE:

A. Yes.

MR. JOHNSON:

Q. Just going in to load forecast, just on the domestic side, MHI has indicated that you are using a methodology which is acceptable, but which consistently underpredicts future energy needs at a rate of one percent per future year, and I just want to get your comment on

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that finding by MHI.
MR. HUMPHRIES:
A. Do you want me to comment on it?
MR. GOUDIE:
A. Yeah, we should switch out, I suppose, because load forecasting would be Paul's.
MR. HUMPHRIES:
A. On the construction issue, Mr. Chair, would it be okay to switch back?
MR. CHAIRMAN:
Q. Oh absolutely.
O'REILLY, Q.C.:
Q. Paul Stratton, you have his bio there.
MR. STRATTON:
A. It's Paul Stratton, could you just refresh the question for me.
MR. JOHNSON:
Q. Yes, Mr. Stratton, I wonder if you could comment upon MHI's finding that your domestic forecast methodology is acceptable, but consistently underpredicts future energy needs at a rate of one percent per future year. Any comment on that observation?
MR. STRATTON:
A. Well the one percent error that they've seen

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over that historical period would reflect both the--any modelling error, that would be in the model, as well as any assumptions that go in to feed that model. I mean, it's also an indication of bias and as a load forecaster, I am very concerned that there would be any bias in the model, but at the same time, I'm less concerned because over that period it's underforecasting and over that time period our models would be continually updated to adjust and to correct for any errors that would occur over that time.
MR. JOHNSON:
Q. So does the--I understand the load forecast is going to be updated for DG3 in any event.
MR. STRATTON:
A. That is correct.
MR. JOHNSON:
Q. But in terms of the DG2 forecast, does that embed an over estimation or an under estimation of future load for the domestic class?
MR. STRATTON:
A. No, it does not necessarily mean that that forecast would under forecast load or in--

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towards the future, no.
MR. JOHNSON:
Q. Okay, all right, they were just talking--okay, I understand. In terms of the industrial forecast, you know, we have a small number of industrial customers. Tell us how you get a handle on industrial energy demand forecasting at Nalcor?
MR. STRATTON:
A. We request from our industrial customers, typically twice a year, what their requirements would be. We assess those requirements against any recent load that they have. If there are variations that we see, significant variations in the history verses where they expect to be, we would communicate that with them, and have probably, you know, discussions with them probably over the phone. And based on those assumptions, we may make minor adjustments to their projections, but otherwise we--they are the keepers of their load, they understand their load, so we typically take, primarily take their loads.
MR. JOHNSON:
Q. So they have a sense of what they're going to

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be doing in terms of production, shutdowns, maintenance, all that type of -
MR. STRATTON:
A. That is right because we're not inside looking at those operations and they understand how they're--how the changes in their operations would affect their loads and we wouldn't be in tune to that, so -
MR. JOHNSON:
Q. So just to get a sense then, as between DG2 and where we sit, when was the last time you had a chat with each of the industrial customers about what their load requirements were going to be?
MR. STRATTON:
A. Well, as part of our, Hydro's operating review, we've just recently completed an assessment of the industrial forecast, so we just heard back from them within the last month.
MR. JOHNSON:
Q. And this is a normal twice a year thing?
MR. STRATTON:
A. That would be part of a twice a year forecasting process that we undertake.

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MR. JOHNSON:

Q. Okay, and I guess relative to where they thought they were going to be at DG2, is there any material changes?

MR. STRATTON:

A. There are no material changes in the industrial outlook for many of those customers that has been provided to us.

MR. JOHNSON:

Q. And how far are they--when you go to them, say recently or they come to you, how far out are they looking?

MR. STRATTON:

A. We typically request a detailed monthly forecast for a two to three year period and then just, their annual requirements up to five or six years after.

MR. JOHNSON:

Q. So that's information that they provide twice a year and each time it looks out four or five years.

MR. STRATTON:

Q. That is a request that goes out to the industrial customers twice a year, yes.

MR. JOHNSON:

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Q. The industrial forecast has been wrong over the past number of years. I presume it's been wrong. I think it's been wrong because of the, sort of, unprecedented happenings in the pulp and paper industry, at least in this province with Stephenville and Abitibi in Grand Falls, et cetera. So, there is some interest in the forecast assumption for, particularly Corner Brook Pulp and Paper because the DG2 forecast would, sort of, embed an assumption that Corner Brook more or less continues rate out for the duration of the sunny period. And just give your comment on that in terms of whether that's unduly optimistic or reasonable or what's the thinking on that?

MR. BENNETT:

Q. This is Gilbert Bennett. I think that the facility is in operation, existing facility, they're continuing to run their business, so that's one aspect, that's one aspect of the industrial forecast. The other forecast of the industrial forecast is we did not forecast any additions to industrial demand in the form of new customers, so with the information

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that's available to us, we have a customer who is signalled to us that they're continuing to operate their business, so I have difficulty forecasting that that mill is going to disappear, I mean, that action of itself has significant consequences and that's something that we have no basis to do. We have the customer there, they're in operations and I think the best way to address, you know, those kinds of potential changes in demands is using the method that we did, through a sensitivity analysis to test what would happen if in the long term any of the forecasts were to vary, so as we can come at it that way from a probabilistic perspective and just see what the impacts are, as opposed to identifying, you know, the future of a particular individual customer in our forecast.

MR. JOHNSON:

Q. You mention "probabilistic", is it probabilistic is the sensitivity test?

MR. BENNETT:

A. Well I guess it is in the sense of we've looked at a couple of scenarios where, for example, 374 gigawatt hours per year of demand

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disappeared, another one at 750, so we look at that in the same was as CDM. We also did another sensitivity analysis where we said let's see how much demand would have to disappear in order for the CPWs to be the same, so there's a combination of approaches there.

MR. JOHNSON:

Q. Just back up for a second, just so we can understand because you referred to the loss of 375 gigawatt hours or, I think in sensitivity tests you term that conservation, CDM et cetera, and now you just linked that to the Corner Brook situation in a sense, what were you getting at, how are they thematically linked?

MR. BENNETT:

A. I think the question was what's happening with the load forecast.

MR. JOHNSON:

Q. Yes, that's what I meant, I don't mean that means Corner Brook, I'm just -

MR. BENNETT:

A. Right, so there were three sensitivities on the load forecast, one was how much load would

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have to disappear immediately in order for the CPWs to be the same, and then the other test that we did on the load forecast was a more gradual reduction in demand over a longer period of time and that's the 375 and 750 gigawatt hour per year loss in, I guess, forecasted demand out to 2031.

MR. JOHNSON:

Q. So in terms of, just to flip around the other side for a moment, the pessimistic view of not having any more industrial load than what we've had now going out to 2067, is that--is that what you're supposed to do to say basically, look, there's no one here in the immediate offing (phonetic), we've got no firm commitment to take power energy from us, so let's just assume that it doesn't exist for the planning period, you know, why did you pitch on that assumption?

MR. BENNETT:

A. Well I think we have had--I mean to be candid, we have had comments raised in our public consultation that we're overstating our forecast, so coming at this from the perspective of saying, you know, we think this

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is a reasonable utility forecast, we're not going to make any significant variations in our industrial forecast and we've looked to sensitivities and see what happens when demand decreases off our forecasted amounts.

MR. JOHNSON:

Q. I'm looking for the--the sensitivity on the 880 gigawatt hour load would be in -

GREENE, Q.C.:

Q. Nalcor's submission, page 126 and 158 has the loss of 880 gigawatt hours.

MR. JOHNSON:

Q. Yes, thank you, Ms. Greene. If we could pull that up, Mike?

GREENE, Q.C.:

Q. Page 126 of 158.

MR. JOHNSON:

Q. It's table 29.

GREENE, Q.C.:

Q. Volume 1 of their submission.

MR. JOHNSON:

Q. Okay, so you indicated, Mr. Bennett, that you tested basically how much load would have to come off the system for the two CPWs to draw even and that comes out to zero, lost of 880

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gigawatt hours assumed starting 2013.

MR. BENNETT:

A. Now that sensitivity was updated, so this analysis was updated in response to the RFI.

MR. JOHNSON:

Q. Oh, I'm sorry, yes, I'm sorry, it's on the flip and I have it there, I'm sorry, because that was a bit surprising, actually. So, yeah, if we lose 880 gigawatt hours at 2013, there is a preference, a much reduced preference for the Muskrat Falls option, down to 400 million dollars and basically give us an overview on the math of what's happening to shrink the preference and we know there is oil implications, just walk us through that.

MR. GOUDIE:

A. I can speak to that, it's predominantly oil, that's how much leverage oil has in that case because it's 880 gigawatt hours of our marginal production coming out of the production costing, so it is oil -

MR. JOHNSON:

Q. So you would be able to meet the island load with your Hydro electric resources, which is cheaper than oil and that's the big difference

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in the seeping up -

MR. GOUDIE:

A. You're going to draw up your most expensive generation source and that's going to be oil and in the Interconnected case, because that sensitivity starts in 2013 and we're still burning oil right through to 2017 when we commission the in feed, so that's why there's a reduction in the interconnected CPW from 6652 down to 6217.

MR. JOHNSON:

Q. Right, okay. And is there any assumptions being made about what the cost of the replacement hydro electric energy is?

MR. GOUDIE:

A. Not in that load sensitivity, and in fact, just to follow up a little bit, there was a PUB RFI that requested that we run this particular sensitivity through the strategist program so that we could take account of the capacity impacts on the system, and that was subsequently done for PUB 51, I believe, or 52, and the preference for the Interconnected Island option would have increased from 408 to around 550, I believe.

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MR. JOHNSON:
Q. Do you want to bring that one up?
MR. MCNIVEN:
Q. I wasn't sure which one -
MR. JOHNSON:
Q. PUB 51, I believe.
MR. MCNIVEN:
Q. Sorry about that.
MR. GOUDIE:
A. So you can see in this RFI that if you take into account the capacity impacts on the CPW analysis, in addition to just the fuel savings, that the preference for Interconnected Island actually increases to 545 million dollars.
MR. JOHNSON:
Q. So just translate for us the capacity impacts, why would the preference increase by a hundred and some odd million?
MR. GOUDIE:
A. Well you would expected it maybe to go the other way, that on the isolated island case we dropped 880 megawatts or 880 gigawatt hours of energy and you would expect that that would have pushed out the timing of our energy

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requirements, so that any capacity additions that we would have coming down the pipe, they would get pushed further in time and that would decrease their cost from an economic point of view. But what happens here is that because those hydro plants, essentially are pushed out in time that we would have built sooner under the Isolated Island case, there's now going to be additional oil burnt on the Isolated case than otherwise would have been the case. And that actually increases the preference for Interconnected Island marginally.
MR. JOHNSON:
Q. So the strategists, your strategists can tell you what's the optimal roll out?
MR. GOUDIE:
A. Yes.
MR. JOHNSON:
Q. Okay.
MR. GOUDIE:
A. And again, this was not a case that was specific to Corner Brook Pulp and Paper.
MR. JOHNSON:
Q. If it were made specific to the case of Corner

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Brook Pulp and Paper, what would be the difference?
MR. GOUDIE:
A. Under the Isolated Island case, there would be--well, there's a lot of different kind of outcomes here now, right. Assuming that the Deer Lake Power Plant continued to be operating and I don't think it really matters whether the owner of that resource today or whether we own the resource, but there would be some kind of transaction cost that has to be accounted for under the Isolated Island case, because if that power is going to come into the grid, then it has to be acquired and paid for. It's not going to come into the grid free, so that's an important consideration. So what that will do, obviously, will again increase the preference for the Interconnected Island case.
MR. JOHNSON:
Q. In terms of the sensitivity test, again going back to your sensitivity test on page 126 of 158, volume 1, Mike.
MR. MCNIVEN:
Q. I'm sorry, the reference again?

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MR. JOHNSON:
Q. It's page 126 of volume 1.
MR. MCNIVEN:
Q. Of the submission?
MR. JOHNSON:
Q. Yes. The testing, I'm just interested in the sensitivity testing on moderate conservation and aggressive conservation, how did you decide what was moderate and what was aggressive for purposes of your sensitivity?
MR. GOUDIE:
A. Those targets would have been identified in a study that Hydro and Newfoundland Power commissioned, I believe in 2007 or 8 regarding conservation potential.
MR. JOHNSON:
Q. Could you put the aggressive conservation of, by 2031 having taking 750 gigawatt hours off the system, can you put that into some sort of context of what that would mean? Can you translate that for us, in terms, you know, put it in maybe less load per year going forward or, you know, how significant is it?
MR. GOUDIE:
A. Well cumulatively it's very significant,

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obviously. I don't have a calculator and I shouldn't be making calculations up here, so -

MR. JOHNSON:

Q. Okay, no.

MR. GOUDIE:

A. But you could relate that to the number of barrels of oil at Holyrood quite readily.

MR. JOHNSON:

Q. Yes, the heat rate and calculate it up. And so what do we see, just walk us through the numbers, if you will. I see that through the rest of conservation, is this just pure oil savings again?

MR. GOUDIE:

A. In the moderate conservation case, it's pretty well fuel savings only.

MR. JOHNSON:

Q. Yes.

MR. GOUDIE:

A. But we would allow for some program costs on the cost side, so we got a benefit side that's fuel, we got a cost side that will be program. In the aggressive conservation, sensitivity, there was an additional credit provided that reflected basically deferring a gas a turbine.

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MR. JOHNSON:

Q. Okay.

MR. GOUDIE:

A. So there was some capacity credit given to the aggressive conservation.

MR. JOHNSON:

Q. So embedded in the numbers which lead to the preference number, there are assumptions and inputs as it relates to the costs of actually achieving the energy reduction?

MR. GOUDIE:

A. Yes, that's correct.

MR. JOHNSON:

Q. Okay. Mr. Chairman, I'm thinking at this point I probably would like to take a break and have a look at it and start again fresh in the morning.

CHAIRMAN:

Q. Okay, we will start at 9:30? But before--can I piggyback on one of your questions to Mr. Bennett on this carbon business. You used a number with respect to 100,000 tonnes and you used a number with respect to dollars. So, can you convert that into a, I guess it would be a carbon charge per tonne? Do you know

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what I'm talking about?

MR. BENNETT:

A. Yes, I know where you're going. Maybe if it's helpful, I can come back tomorrow morning with a sheet.

CHAIRMAN:

Q. There's no hurry, I mean, whenever you're--I just -

MR. O'REILLY:

Q. I think that's your question too, isn't it.

CHAIRMAN:

Q. I think it would help, like, I believe in trying to keep things simple, but I don't think I'm a simpleton, but I like to try and understand it in terms of numbers and when I think about carbon and consumers think about how much is going to cost me. And you got to think of how much per tonne, I assume, and then you, you know, that's on a yearly basis. Do you know what I'm talking about?

MR. BENNETT:

Q. I understand where you're coming from. S, we can report back.

CHAIRMAN:

Q. And on the 1 in 150, 1 in 50, 1 in 150 and 1

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in 500, I mean, what you guys are saying there is that from the point of view of marginal efficiency or marginal cost, it's better to be spending your last dollar on backup gas generation on the Island, rather than going, saying, from 1 in 50 to 1 in 150, is that your basic argument?

MR. BENNETT:

A. That's the basic point. We prefer to invest in additional generation locally, so that we reduce the impact of line failure.

CHAIRMAN:

Q. Cause you still got to have your backup generation, even if it's 1 in 500? You still got to have some -

MR. BENNETT:

A. That's right, because it still would be a consumer effect if we did lose the line in that very unlikely event.

CHAIRMAN:

Q. And on the point with the federal loan guarantee, I mean, there's no downside risks. We can take it off the table because there's no downside risk to the federal--if it comes in, if we get a federal loan guarantee, it can

only enhance the viability of Muskrat Falls, is that what you're saying, it won't make any different to the Isolated Island?

MR. GOUDIE:

A. That's correct.

CHAIRMAN:

Q. So 9:30 tomorrow morning? We'll adjourn until then.

Upon conclusion at 4:45 p.m.

CERTIFICATE

I, Judy Moss, 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 Pubic Utilities on the 13th day of February, A.D., 2012, 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, Newfoundland and Labrador this 13th day of February, A.D., 2012

Judy Moss

-F-

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