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LIST OF UNDERTAKINGS

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(9:04 a.m.)

CHAIRMAN:

Q. Thank you. Good morning. Adjusting to the post election drama that's unfolding and will be, I guess, over the next little while. Good morning, Ms. Newman. Are there any preliminary matters before we begin?

MS. NEWMAN:

Q. Good morning, Chair and Commissioners. Yes, I did want to mention there was a document circulated the last day which was the key performance indicators. There was a response to an undertaking from Hydro and there was an inquiry as to the number, that is U-Hydro No. 3 response. Also, I understand that counsel for Newfoundland Hydro does want to address a couple of preliminary matters. But before we do that I did want to mention that we have a couple of special visitors here today. I don't know if everybody can see them in the back there. Mr. Michael Browne and Mr. Jeremy Power are here to observe our proceedings and I thought we should welcome them appropriately.

CHAIRMAN:

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Q. Oh, absolutely. Welcome. Hope you find the proceeding here this morning of interest. We'll try to make it as interesting as possible for you in any event.

MR. KENNEDY:

Q. Explained it wasn't a murder trial, yet.

CHAIRMAN:

Q. Anyway, welcome. Sit back and relax and hopefully you'll learn something. We can't promise that, but hopefully you will. Good morning, Ms. Greene.

GREENE. Q.C.:

Q. Good morning, Mr. Chair, Commissioners. There were three undertakings provided on Tuesday, October 21st and Hydro is in a position to respond to them at this time. And I've discussed this with counsel for the Industrial Customers and he has agreed, as we have done in the past, to do it in this manner. The first undertaking is found on page 138 of the transcript of October 21st, and it relates to the minimum storage target illustrated on Schedule 4 to Mr. Haynes' evidence. And you can see the specific undertaking is provided there at line 19, and it relates to the green

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line on Schedule 4 of the minimum storage targets, and that's Schedule 4 to Mr. Haynes' evidence. The specific undertaking related to the inputs to determine the shape of the green line. And I wonder, Mr. O'Reilly, if you could bring up Schedule 4, please? We've had some discussion, Mr. Haynes, about this particular schedule. And I wonder again if you could indicate first what the red line is there on that?

A. The red line is basically the maximum storage that we can physically contain in any particular given time, given the, you know, the PMF or the peak maximum flood expectations or projections for the island. So it's basically the physical implications of the reservoirs, the heights of the dams and so on.

Q. So if we get--the water is near the red line, Hydro staff get nervous, is that correct?

A. Well, we are very nervous because, you know, any kind of a change in the system at all can precipitate a spill from the reservoir system.

Q. The green line, first what does the green line represent?

A. The green line is the minimum storage target

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MR. HAYNES:
in terms of energy that all our major reservoirs on the Island Interconnected System can contain at any given particular time in order for us to meet the firm sequence. So it's the amount of energy that we target to have in storage in the hydraulic reservoirs that along with the Holyrood and the NUG purchase contracts will allow us to meet the firm sequence which we anticipate could start at any--you know, it's planned to start at any particular time.

Q. And what are the inputs that determine the shape of that green line?

A. There are several. The inflow sequences that determine the target are by definition, obviously as we mentioned a couple of times, a particularly dry sequence which was basically 1958, late 1958 to the spring of 1961. And there were some other lesser significant but noteworthy dry sequences since then that had some influence on that curve. The shape of the minimum storage curve is dictated by the pattern of inflows experienced during the vary low inflow sequences. And it's also largely

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dictated by the actual firm forecast load that we anticipated seeing. In fact, that's a very big driver of the shape, it's the--you know, it's the--our planned firm load commitments during any particular time given all the other circumstances. As we add generation sources such as Granite Canal or power purchase agreements, such as the NUGS, it does impact that particular curve. And if we were to--for instance, when we changed the Bay D'Espoir runners, it would have an impact or if we up--you know, if we upgraded Holyrood unit one and twos, we did quite awhile ago, they also impact that shape. And it does change from year to year, particularly during my load forecast. And we did present in IC-160 a series of curves from 1994 to 2002. And if you were to refer to those, it actually does show variation from year to year of that green line.

Q. And the blue line and the magenta line represent 2002 and 2003 to date where the storages have been, is that correct?

A. The blue line is 2002 and the magenta line is actually up until April. And there was an RFI

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requested by Newfoundland Power which updated it to July or August. I forget the number; I apologize. But the magenta line is our track record this year.

Q. Now, in his cross-examination Mr. Hutchings suggested that the minimum storage target green line there would be the sum of individual reservoir target lines. Is that correct?

A. No, that's not correct. There is no minimum target for our reservoirs. Basically we have, as we talked about the red line, the maximum storage capability. We do not have minimums on any particular reservoir. We try to manage the whole. I think if you were operating a single plant where you may employ a guide curve in a traditional way because you had a fairly base load and there's no opportunities for inter reservoir optimization. And we take a fair bit of time to basically maximize the hydraulic production to minimize thermal production and to basically maximize the overall, the overall economics in favour of our customers.

Q. So that green line, the minimum storage target

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line is not the same as a guide curve for the system, is it?

A. No, it's not.

Q. The next undertaking that we'd like to address is found on page 154 of the transcript, and I don't think we need to go to it, but it relates to the load growth. And first I did want to refer to page 33 of Mr. Haynes' evidence, line 6. Beginning there on line 6, Mr. Haynes, is a sentence that states that Hydro's current ten year annual average load growth projection for the Island Interconnected System is 1.3 percent. Could you explain what period of time is represented by that sentence?

A. Yes. When we discussed this on Tuesday, I did reference the load forecast payable, which I wasn't fast enough to find. It's actually Schedule 14. And the 1.3 percent is the anticipated energy requirements in 2012 compared to the actual experienced in 2002. And those numbers are in the table and it is 1.3 percent, the average annual growth.

Q. The specific undertaking related to the average annual growth for the period from 2003

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GREENE, Q.C.:

to 2011 prior to the Voisey's Bay nickel load. What is the projected average annual load growth for that period from 2003 to 2011?

A. It's 0.6 percent per year for that eight year period.

Q. If we compare that now for the period from 2002 actual to 2011 forecast, what is the projected annual load growth for that period from 2002 actual to 2011?

A. And that was 0.8 percent per year.

Q. The last undertaking that was given on Tuesday is found on pages 168 to 169 of the transcript. And the specific undertaking related to providing an explanation given by Newfoundland Power for their revised load forecast provided during the 2001 General Rate Application. And here I do have some documents to distribute. What I'm distributing are extracts from the transcript and from final argument from the 2001 GRA where this issue was raised. And they haven't been filed to date, so they're not part of the official record for this hearing, so it's necessary to distribute them in hard copy.

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MS. NEWMAN:

Q. Ms. Greene, do you wish to make them exhibits to the testimony of Mr. Haynes?

GREENE. Q.C.:

Q. I'm going to speak to them; Mr. Haynes is not, so perhaps if we--the purpose of distributing these hard copies is to illustrate that this issue was raised during the 2001 General Rate Application and it was decided by the Board. And in light of the Chair's comments at the beginning of this hearing, I question the merit of raising an issue that has already been reviewed at length in the 2001 GRA and decided by the Board.

The first document that I'd like to refer to is the transcript of November 6th, 2001. Mr. Budgell was the witness for Hydro at that time. And beginning on page 19 of the transcript of November 6th you will see that Ms. Henley Andrews questioned Mr. Budgell with respect to the revised load forecast that had been provided by Newfoundland Power and was filed by Hydro in its update that was provided in October of 2001. And in fact, the questioning was at length. I didn't provide

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the whole transcript, but the balance of the day of November 6th was with respect to this issue of the reasonableness of the revised forecast from Newfoundland Power. The specific undertaking that was asked on Tuesday was to provide the explanation that was given by Newfoundland Power for the revised load forecast in 2001. And I have provided to you page 19 where the exact same question was asked of Mr. Budgell in 2001. And I guess the answer doesn't change in 2003. When you look at line 60, you'll see Ms. Andrews ask Mr. Budgell "What's your understanding of Newfoundland Power's rational for the change?" The answer that Mr. Budgell gave is then contained, "I haven't got any explanation other than that fact that the new forecast reflects an update to the load. Newfoundland Power normally reflects their energy usage and then applies a load factor on their, I guess, on the individual energy demands on the system and they do every time, I believe, they do a forecast, they do an update to that. I'm assuming that the sample that they're using reflected this change." And I won't read

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others, but I have provided some pages where there was cross-examination at length on this issue. And as I said, it actually took the rest of the day of November 6th with respect to historical load forecast of Newfoundland Power and how it compared to the revised 2001 load forecast. And in fact, there was additional cross-examination on November 7th on the issue.

The next document that I have circulated, there's no heading on it but the page No. is 111. And this is an extract from the written submission of the Industrial Customers in the 2001 General Rate Application. And the section that I have provided an extract of relates to 2002 forecast load. And you will see on page 12 in the second full paragraph where the issue of Newfoundland Power's revised load forecast is raised. And then from page 112 to 113 there is the argument as to why the load forecast was not reasonable and should not be accepted by the Board to be used in setting the 2002 rates. And you will see on page 114 of that submission where the Industrial Customer submitted that

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GREENE, Q.C.:

Newfoundland Power's revised demand and energy forecasts are not reasonable and should be rejected. So that was their written argument.

The third document I have circulated is an extract from the transcript of January 28th, 2002 which was the oral argument at the conclusion of the 2001 GRA. And I have provided pages 34 and 35 of the transcript. And I would draw your attention to line 100 where again we get the specific reference to the Newfoundland Power revised forecast. And you'll see there that in oral argument, as well, the Industrial Customers raised the issue that the revised forecast for Newfoundland Power was not reasonable and should be rejected by the Board. So that's beginning at line 100 on page 34 and continuing over to page 35 in the top paragraph on page 35.

The Board, in Order P.U.7 approved the Cost of Service that was filed by Hydro which included the revised Newfoundland Power load forecast that was filed in October of 2001.

So with respect to the specific

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undertaking, the answer to the question is the same as was given in the fall of 2001, which is that it was based on Newfoundland Power's review of the load forecast as they had done in the past. However, our position is that this issue which related to the load forecast to be used in setting the current rates is a moot issue, it was already decided by the Board and should not be readdressed at this time in this hearing as there is no--as it does not deal with the future rates but with respect to the current rates.

So those are the responses, Mr. Chair, to the three undertakings that were given on Tuesday and included what I had as preliminary comments for this morning. Thank you.

MS. NEWMAN:

Q. Before we move on, just we should label those documents, I guess. We'll call them all Information Item No. 15. 15-A will be the first document referred to, the transcript of November 6th. 15-B will be the excerpt from the argument starting with page 111. And 15-C will be the transcript of January 28th, 2002.

CHAIRMAN:

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Q. Thank you. Thank you, Ms. Greene. Good morning, Mr. Haynes. How are you?

A. Good. Thank you, Mr. Chair.

Q. When you're ready, Mr. Hutchings, please?

HUTCHINGS, Q.C.:

Q. Thank you. Mr. Haynes, just so we're completely clear on this final issue of the Newfoundland Power load forecast, is it your evidence now that Mr. Budgell's answer from November 6th, 2001 on page 19 at line 63 is still correct, that he--that is to say, Hydro hasn't gotten any explanation for the rational for the change?

A. No, we don't have any specific details of the way they calculate those particular numbers, no.

Q. So you did not get any explanation?

A. No.

Q. No. Okay. And you didn't look for any?

A. I think there was dialogue that it was a different number, but we assumed it was done on their methodology for calculating that particular number.

Q. And you were prepared to put that in the Cost of Service on the basis of that assumption?

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A. Yes.

Q. Okay. Would you agree with me that the forecast didn't come true?

A. Most don't.

Q. That is true. And some are closer than others, correct?

A. That is correct.

Q. Um-hm. And would you agree with me that there was a significant variance in the amount of energy--rather, not in the amount of energy, which was actually pretty close, but in the demand that actually occurred in 2002 from the forecast which was included in the Cost of Service?

A. There was a notable difference, but there are many factors that drive that, so, you know, it is a fair bit of variation over the years in any load forecast or any load factor.

Q. I understand that. The question becomes how much reliance we put on these things. Do you know what specific factors caused the 2002 actual demand of Newfoundland Power to be so much higher than the forecast demand?

A. No, I do not.

Q. Okay. If we could just go back to Schedule 4

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GREENE, Q.C.:
for a moment? It's the curves. Yeah. You indicated that there was an influence on the green line here, the minimum energy storage target from some periods other than the 1958 to '61 lowest inflow period. Can you describe for us what else aside from that lowest period from '58 to '61 influences those curves, how other periods of times factor in?
A. There was a dry sequence, not the firm sequence which was experienced in the late summer and early fall of 1987 where we had several months of, you know, sustained low inflow period, so that would actually affect the shape of the line. That is one that I am, you know, have some--am familiar with. So it does actually change the shape. The shape of the line basically is the forecasted, you know, the worse case. The firm is obviously the big thing or the main thing that we try to protect, the three year dry sequence, but there were other--you know, in particular, in 1987 there was a sustained period of dryness. It didn't go for years, but there was a few months where it would have affected our

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average inflows and affected the way that we would operate the system. So that's a--and the green line is evolving over time as we experience--you know, it's not going to have any significant impact if it's a dry months, but if you have two or three dry months which kind of exceed the short term, it can impact that shape.
Q. Okay. So is what you do when you come across a period such as in the fall of 1987, am I understanding that that was the fact--a period that was lower than the corresponding period within--the corresponding months within 1958 to '61?
A. I don't think it was lower necessarily than 1960, '61, but it would have had an influence on other, you know, say, fall periods. Other falls would not have been as dry and so the line would take a dip down in that period of time. But biggest factor is the load, you know, the firm load expectations of the customers or our forecast.
Q. Sure. No, I understand that. So this is some exercise of engineering judgment, I take it, that influences this curve on the basis of dry

Page 19

periods other than your lowest firm period?
A. Yeah, it's engineering judgment, but it's pretty accepted, it is generally accepted hydraulic practice to plan the interconnected--you know, to plan the system that way.
Q. No, no, I'm not challenging--I'm not questioning the -
A. Yeah. But it is standard practice and it is engineering judgment, but it's based on the actual data that did occur and the assumption is that it can be repeated.
Q. Is there some guideline which tells you that you have to take into account this fall period in 1987 or not in altering your curve, which we always understood to be on the basis of that firm period?
A. The curve is generated based on the whole series. The most critical period was the dry sequence of 1958 to '61. There are various other influencing factors and I wouldn't pretend to know them all. But as you go down through and you look at history, you examine the hydraulic series, then basically you generate the scenario that you think that you would be--would be the most as possible to be

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repeated and the one that we would protect against.
Q. You indicated that your goal here in setting that minimum curve is to ensure that you meet the firm forecast load?
A. That's correct.
Q. Okay. What do you use as the firm forecast load for Newfoundland Power in that instance?
A. We use their load forecast, their energy forecast. This basically is energy, not demand.
Q. Sure.
A. We basically use their energy requirements that they project.
Q. And equally with the Industrial Customers?
A. That's correct.
Q. And your own hydro rural customers?
A. Yes.
(9:30 a.m.)
Q. Mr. Haynes, I'd like to discuss with you for a little bit the incident that was referred to in your earlier testimony in September, I believe, of 2003 where you had the station service failure at Bay D'Espoir.
A. Yes.

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GREENE, Q.C.:
Q. What date did that occur?
A. September 18th.
Q. September the 18th?
A. I'm sorry. Yes, September the 18th.
Q. Okay. And were you able to ultimately determine the cause of the failure of station service?
A. Yes. There was an inverter failure which basically is a--converts power from DC to AC, and it failed and the, I guess the root cause is in the protection design which has since been changed. There was an exposure there that in a certain situation when a certain bus was de-energized, if the inverter was removed from service or tripped, it would actually lose the total station service. And that's what happened. That deficiency has since been addressed and repaired and I'm assured will not happen again.
Q. Okay. In September, I guess, normally Bay D'Espoir would be producing significant amounts of energy?
A. Typically, yes, because that would be the time period when Holyrood would be just starting up

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or getting ready and possibly on. It would be, you know, the shoulder season.
Q. Okay. So I take it that when this incident occurred the instructions or operating procedures that are appended to your Exhibit JRH-3 would come into effect, as to say with Appendix A?
A. That's generally correct. Sometimes it would be--you know, it depends on the amount of time that we anticipate getting the particular issue repaired. Sometimes it's a matter of just restarting the machines and it may be only a few minutes; other times there are other events which cause a larger delay if an investigation is required. But generally speaking, that would be followed.
Q. Okay. And how long did it take to get Bay D'Espoir back on, on that particular occasion?
A. Well, that was a very unique problem which we had not experienced and we had actually--I believe there were three machines that actually tripped off the system. And I do not have the time frame. I'm not sure when exactly the plant came back in line fully. I don't have that in mind right now.

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Q. Okay. Can you just give us an estimate of how long it was before, you know, service was restored?
A. Service restored to the customers?
Q. Um-hm.
A. That was, I would suggest that was in less than an hour that the service was restored.
Q. Um-hm.
A. I interpret your question when Bay D'Espoir was restored. There was a bit of a delay because we had some issues to try to understand what exactly happened before we actually go back and take a chance -
Q. Yeah, I recognize it's a different question, yeah.
A. But I think it was probably--I actually don't have that recorded. But typically for an event like that it's usually four to five minutes, but depending on the nature of it is, what time of the year, what other machines are available, particular Holyrood obviously being a big source of energy. I think it was approximately an hour that most things were returned, but I am not definitive on that.
Q. Okay. Can I ask you to look at page 36 of Mr.

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Osler and Bowman's testimony? Blinded by the light, Mr. Chair. Yeah, starting at line 10 there and going down to line 28 the evidence reproduces the sequence of activities in the case where load is lost. And this particular one incorporates the information that was provided in IC-295 about the sequencing of the standby generation. Have you reviewed that listing of 11 steps?
A. I had reviewed it, I had reviewed that before, yes.
Q. Yes, okay. And is this essentially an accurate representation of the steps that would normally be taken in such an event by Hydro?
A. That would be the normal sequence. Obviously there are, sometimes there are, you know, equipment out of service for one reason or another that may not be available, but that would be the general order.
Q. Sure. Okay. And on September, 2003 which of these steps were taken?
A. I do not know. I don't know that detail offhand, but I would assure you that any generation that was available to be dispatched

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MR. HAYNES:
to overcome than would have been initiated by the Energy Control Centre. But I don't know the detailed steps or which particular machines. I know that GNP was on, I know that gas turbines were activated, I know that Newfoundland Power was contacted to initiate their--to do what they could do to start their machines or get them up to speed.
Q. Okay. You said you knew that GNP was activated. I take it that's step 5-E here?
A. Yes. And Roddickton was on. I think St. Anthony was certainly on, Roddickton was on, and I think there may have been some issues on maintenance at Hawke's Bay at the time, at that particular time.
Q. Okay. When you say that Roddickton was on, does that imply that the two NP gas turbines were on as well?
A. The request was initiated, and I know that they had some maintenance issues on one. I'm not sure about the second one.
Q. Okay. I thought I had understood from earlier answers that you'd given that while the request was made to put on the two NP gas

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turbines, they didn't actually get on. Is that correct?
A. I know that one gas turbine did get on. I am not certain whether the second one, the small one actually came into service or not.
Q. Okay.
A. I understand the Green Hill gas turbine had some maintenance issues that it did not actually get into service.
Q. Okay. And the Green Hill is the one on the Burin Peninsula?
A. Yes, it is, yeah.
Q. 25 megawatts?
A. Yes.
Q. Yes, okay. Did your two turbines in Hardwoods in Stephenville come on?
A. I believe they did but I--if they were not on maintenance, they would have been on.
Q. Okay. But you don't know whether they actually came on or not?
A. I would be quite--I'm confident to say that they were, but I -
Q. Okay. And what about the Holyrood gas turbine?
A. I did not go down through the sequence of

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events to see, to determine if each and every step was anticipated. My understanding is that all available generation that we could dispatched would have been dispatched if it was available.
Q. Okay. Do you know if any of the non-firm Industrial energy was interrupted?
A. I don't even know if we were actually delivering non-firm at that particular time.
Q. Okay. I take it you--well, did you get down to the point of reducing voltage at Hardwoods or Oxen Pond's or ask anyone to shed any load?
A. I'm not sure.
Q. You don't know?
A. That would be the normal function in the Energy Control Centre and I would not necessarily get into their clock on each and every event.
Q. Okay. No, I simply assumed because you had already told us that you knew that the Newfoundland Power--or the Great Northern Peninsula generation was on that you had brushed up on this and you were aware.
A. I was aware that that generation was on because it was available and it was there. I

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mean, any actions that the Control Centre take would be, in dispatching the generation, it would be, you know, a ranking from the point of view of the cost of fuel at the time and the ranking order, if you will, for Hardwoods in Stephenville, for non-firm, could change depending on the price of fuel in the tanks. But on an emergency basically it's no holds barred, if you will, to go get things back in service to meet the customers' demands.
Q. Okay. I take it that no issue arose on September 18th, 2003 about curtailing the Interruptible B load?
A. There was no Interruptible B on September--there was no Interruptible B available at that time.
Q. Because the contract had been permitted to lapse?
A. The contract did not cover September anyway.
Q. No, okay. I take it that aside from the Interruptible B contract that did exist, Hydro has no other similar interruptible types of arrangements with any of its customers?
A. Not like that, no.
Q. Okay. The only other issue would be the non-

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GREENE, Q.C.:
firm industrial energy that may be taken at-- happen to be taken at any one point in time?
A. If we were delivering any non-firm at the time, that would have been something that we would have curtailed, yes.
Q. And that would occur after all of your other generation was on, including diesels and gas turbines and everything else?
A. Actually, I think if you go back to, I guess, the report that we have attached to Mr. Osler's, that's actually Item No. 4. We'll maximize hydraulic and steam. We asked Newfoundland Power to maximize their hydraulic generation and I guess what that really implies is that before we actually start to burn a more expensive source of energy, we'd actually curtail the non-firm.
Q. I think I -
A. Or give the Industrials the option to pay those higher costs.
Q. Yes, and that's what Item 4 is.
A. Yes.
Q. You notify them that they could be paying gas or diesel costs, correct?

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A. Yes, and they could obviously presumably decrease their non-firm take.
Q. Yes. They could choose to reduce it or eliminate it at that time. Assuming that they didn't do that, it wouldn't be down until step 6 that you would actually interrupt their non-firm energy, correct?
A. When there was nothing else to fire up, if you will.
Q. Right, okay. So in the situation of an event such as the September 18th event, had there been any similar arrangement to Interruptible B in place, presumably that would have been of assistance in meeting the problems created by that event?
A. The Interruptible B, when it was introduced, I guess, or when it was initiated in 1993, it was more done based on a short-term planning horizon whereby for a short period of time, we saw some issues with peak, and maybe because of equipment availability or because of unforeseen load, the action right here basically is recovering from a--primarily from a--the September event certainly was because we had a failure and a fairly significant

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failure at the Bay D'Espoir plant, and we were in very much of a hurry to get generation on. The Interruptible B, there's time frames were noticed. There's restriction on the hours of the day. The Interruptible B is definitely not the same product as a gas turbine. It's very not compatible. They're not comparable. It was useful for that particular event, when we had an identified significant number of years between when we had an LOH criteria deficiency and an energy balance problem. But it's not the same product as a gas turbine.
Q. Now I wasn't suggesting it was the same product as a gas turbine, but the notice provision that was in the Interruptible B contract was for one hour. Is that correct?
A. I believe that's correct.
Q. Okay. So on one hour's notice, you could get rid of 46 megawatts of load?
A. Yes, for a defined period of time.
Q. Yes, okay. Now if we look at IC-295 on page 2 of 2, we have the information about, among other things, start-up time and dispatch sequence for various standby generation, and if we look at the Newfoundland Power standby

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generation, on the various diesel units, which is the last line, the start-up time is 45 to 60 minutes and the mobile gas turbine, the start-up time is 60 minutes. Is that correct?
A. That's correct.
(9:45 a.m.)
Q. Okay. And together, they provide 13.9 megawatts?
A. Yes, that's correct.
Q. Okay. And would you not see that there would be greater value in getting 46 megawatts within those 60 minutes, than getting 13.9 in that fashion?
A. The 13.9 megawatts, once they're started, at available for as long as we want, and you know, and so on. The 46 megawatt Interruptible B has certain time restraints on the hours of the day when it can be used and on the months that it can be used. So it's still not the same product. But, you know, I mean, certainly there would have been some-- the 46 megawatt Interruptible B was to look after the winter period and it's--I mean, when we go down to item No. 9, I mean, we could request the Industrial Customers of

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MR. HAYNES:
Newfoundland Power, as you start going down that pecking order, if you will, you will eventually get to curtailing load anyway.
Q. Now, but that's -
A. Most of our -
Q. - that's curtailing firm load, correct?
A. Yes, that's curtailing firm load, yes.
Q. Okay. And that's something that nobody plans for, except in an emergency situation, correct?
A. That's the last resort.
Q. And that causes disruption and cost to all of your customers, correct?
A. Yes, it would.
Q. Yes, okay. Overall, wouldn't it have been nice to have 46 megawatts Interruptible B available to you on September 18th?
A. For that one event, you have to evaluate the cost and this overall and I would be reluctant to--I don't think that at the end of the day it would have been something that we would have bought for that particular single event.
Q. What is your current goal for demand side management programs or target?

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A. Basically we have the HYDROWISE Program and primarily that's our single biggest effort or the single thing that would contribute to demand side management over time.
Q. Are you still filing annual reports with the Board on demand side management activities?
A. I'm not certain. I'm not certain that we do or do not.
Q. Okay. I noted that that was directed in the 1992 referral and you don't know how long that went on after that, do you?
A. I'm not certain.
Q. Okay. I understand as well that your target at the time of the 1992 hearing was to get 50 megawatts from Industrial Customers by 1993 and 25 megawatts from retail customers by the mid 1990s. Do you know if you met either of those goals?
A. I have not reviewed that. I do not know that history.
Q. And at the present time, you have no particular target in mind for reducing demand by demand side management activities? Is that correct?
A. We have, in the isolated diesel areas,

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reviewed demand side management opportunities as generation expansion particularly is required, but on the bulk system, we have not taken any significant effort along those lines and as I've mentioned in previous testimony that the--particularly from a residential customer point of view, the biggest customer base is not ours, in fact, it's Newfoundland Power's.
Q. If we look briefly at IC-300, here Hydro was asked about the occasions since 2000 when Newfoundland Power's generation has been dispatched by Hydro to cover system capacity peaks, and at the time this answer was produced, there was only one occasion and that was on January 30th of 2003. Do you know whether or not this answer takes into account the September 18th situation?
A. I would suggest that the answer in--well, the answer in 300 was with respect to our system capacity peak, which would have been, you know, your one event a year, maybe two events a year. September certainly would not have been a peak month but, as I indicated, we did request Newfoundland Power to start the gas

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turbines and to do that and I know that one did not--they could not get one on or, you know, it was on maintenance or whatever. I'm not sure about the others.
Q. Okay. Just one point for clarification arising from some questions Mr. Kelly was asking you. Can we put up LBB-3, Mr Brockman's evidence? Back one page. That's it. Can we get all that on--the two tables on one screen? Okay. This was, as I understood, a comparison of the peak and energy forecast from 1990 and the same peak and energy forecast from the 2003 hearing. I take it that all of the numbers we see here are forecast numbers and there are no actual numbers on this schedule. Is that your understanding?
A. Based on the dates, yes, that would be correct.
Q. Okay. So what we're looking at is a forecast from 1990 and another forecast from 2003. Can you give us any number which would put into context the actual peak in any of these particular years?
A. That has been provided in a couple of RFIs, if

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MR. HAYNES:
you give me a second. I don't know if it was Newfoundland Power or the Industrial Customers who asked that question offhand.
Q. I don't think we need them all, Mr. Haynes.
A. No, I just can't find it. I mean, the forecast--I mean, typically the forecast for the next year is reasonably close. Obviously it varies depending on the weather, and then as you go along the time, there's often times a larger error. But there were several RFIs filed with a forecast history. Actually, I think I have them here, I'm sorry. The long-term planning load forecast for total Island Interconnected System was filed as IC-270, and if you go to IC-270, page 2 of 3, for instance, in 1993, actually that's a very long, long term. There was another one, I'm sorry. I cannot find it at my fingertips but I assure you it's there, I'm sorry.
Q. Yes, well -
A. There's several. There was a whole--there were a series of planning forecasts filed.
Q. Yes. What I'm trying to get to really is the actuals and I think from your Schedule 11, the

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actual Hydro Island requirement for 2002 was 1403 megawatts. Is that correct?
A. Yes, that's correct.
Q. So would that be comparable to the forecast peak megawatts for 2003 of 1578?
A. I think the 2003, 1578 would be the total Interconnected System requirement.
Q. Okay.
A. I think the 1403 is the Hydro Island requirement.
Q. All right. Okay. So you don't have, in your evidence, the total island requirement for 2002, do you, actual?
A. In 2002 actual, the total island requirement is on Schedule 14. The actual was 1592 megawatts.
Q. Yes, okay. So that would be the number that's comparable with the forecast, 1578?
A. Yes.
Q. For -
A. And that's the number that, you know, I think I may have inferred or implied yesterday or the day before that what we have in these particular things is we plan for the total island forecast of all, you know, including

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the Industrial load behind their generation and so on, so this is the Interconnected Island requirements, regardless of who supplied.
Q. Okay. All right. That covers that point. I'd like to discuss a little further with you the issue of the Newfoundland Power generation and you reviewed some of this material with Mr. Kelly earlier. I take it the real issue here is how we deal with the fact that Newfoundland Power does have its own both hydraulic and thermal generation and how that should impact the cost of service to all of the customers. Is that really the issue we're trying to get here?
A. Can you repeat that? I'm not quite sure I understood what you asked.
Q. Well, obviously if Newfoundland Power had no generation of its own, this wouldn't be an issue, would it?
A. Well, there would be no generation credit applied because we would be basically filling the--presumably Newfoundland and Labrador Hydro would be providing the generation to their total requirements.

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Q. Okay. So what we need to address is how to take into account, in the fairness possible manner, the fact that Newfoundland Power does in fact have generation facilities of its own, correct, that needs to be addressed in a cost of service situation?
A. I believe it has been addressed.
Q. Yes, and it needs to be addressed?
A. It has been addressed, I thought.
Q. Yes. And it has been because it needs to be?
A. Yes.
Q. Okay. You're trying to get one question ahead of me, Mr. Haynes.
A. I apologize.
Q. We take them one at a time.
A. I'll try not to do that.
Q. If we take them one at a time, I think we'll make better progress. You've mentioned in the course of your evidence that you don't--you're not really in the field of the cost of service and you don't feel that you should be addressing specific issues arising out of the cost of service study itself. Is that correct?
A. You will get much more competent answers by

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MR. HAYNES:
asking Mr. Banfield and Mr. Greneman.
Q. Okay. And equally, you're not comfortable with addressing rate design issues?
A. No, that's correct.
Q. Okay. So harkening back to my opening remarks about the three classes of issues we have here, aside from cost of service and rate design, are the revenue requirement issues. So those are the issues that--the issues that you address fall within that category? Is that correct?
A. Well, I guess, from my perspective, I guess, the position we basically are there to fulfil the needs of the system load and we operate and maintain the system. That's primarily my role.
Q. At the lowest possible cost consistent with reliable service?
A. Exactly.
Q. Yes, okay. And that's where the revenue requirement comes from, that's the lowest possible cost?
A. That's a big part of it, yes.
Q. Right, okay. Now from the point of view of

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meeting the requirements of the system at this stage, I take it you regard the Newfoundland Power generation, both hydraulic and thermal, as being useful? Is that correct?
A. Yes, we do.
Q. So from your point of view, if Newfoundland Power's thermal generation were to disappear tomorrow, would you go out and buy generators to replace that?
A. If the Newfoundland Power generation were not available -
Q. Thermal generation.
A. Pardon?
Q. Thermal generation.
A. Just the thermal generation were not available, what that would do, it would impact our LOLH calculations and it would--I'm not quite sure at what particular time, but it would definitely affect, quite possibly affect the timing of the future megawatt requirements or, you know, some peaking plant capability, because they would not actually--the diesel plants or the gas turbines would not actually remove energy from the system because we don't depend on that for firm, but it would affect

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the LOLH.
Q. Yes, okay. So if it affected the LOLH to the extent that you needed additional capacity, you know, you had to go out and buy a gas turbine, would you look at all into what the cost effects of that would be on particular customers or would you just be looking for the most economical way to meet the need?
A. We would look at the most economical way to reinstate the planning criteria that has been adopted at 2.8 hours per year. You would look at--you would have to look at the whole. You would have to look at the energy situation and the timing and so on, and I don't think you could look at one specific aspect. You have to look at the whole, at all the options and what they actually bring to the table.
Q. Okay. Directing my question to the production department, would it be any concern of yours as to what the impact on particular customers would be of replacing existing thermal generation owned by Newfoundland Power with new thermal generation owned by Hydro?
A. The production division and Newfoundland Hydro would basically propose to do what is the

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least cost for the consumers or the overall cost of service.
Q. That cost would disappear off your desk into the cost of service study, and from your point of view, you don't much care where it goes after that?
A. Well, no, I wouldn't put it that way. I certainly do care, and I certainly am sensitive to the implications, but basically we plan the system--we plan the Island Interconnected System to meet a certain criteria and, you know, given that that is an appropriate criteria, then what is the least cost to do to meet that particular criteria, we would propose to the Public Utilities Board for approval. And obviously, there are repercussions in the cost of service and so on, but you know, it can be met by Hydro sources. It can be met by NUGS and so on. There are a myriad of different things that we would consider to achieve that objective.
Q. As I understand it, the Newfoundland Power hydraulic generation is used by Newfoundland Power and you really don't have any connection with that, do you, other than perhaps asking

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GREENE, Q.C.:
them to optimize it in an emergency situation?
A. The average energy production of Newfoundland Power's hydraulic resources is considered obviously as, you know, in the energy forecast that we provide, and the megawatts are there and if we--you know, they are there. We assume they're there at the 78 megawatts during peak on a normal basis and if we have any deficiencies, we would certainly call them to ask them to basically, you know, turn them up a bit higher, if required, but we would only do that when--and they do achieve a fairly--a fair, high available--I'm sorry, a high availability in terms of megawatts during peak. But we would call them if we saw any deficiencies or any shortfalls, but ordinarily, if it wasn't required, they would manage it up to about 75 or 80 megawatts anyway.
Q. Okay. And as I understand it, that's power that's relatively cheap in the context of this system?
A. I would assume because most of them are older plants, not all, but that would be a

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Newfoundland Power--I don't know their actual production costs per generating plant.
Q. No, but one would assume that it'd be much less than the cost of producing that energy in Holyrood?
A. I would think, certainly less than Granite Canal, if you will.
Q. Yes.
A. The newer plant.
Q. Right. In terms of the Newfoundland Power thermal generation then, I take it you don't plan on having any energy produced by that generation? Is that correct?
(10:06 a.m.)
A. The only thermal plant on the island that we actually plan any energy production from is Holyrood. We don't plan for firm energy from any of the diesel plants or gas turbines, regardless of ownership, because of the cost of operating, you know, the high fuel costs.
Q. And that includes Newfoundland Power's thermal generation?
A. Yes, it does.
Q. Now on the question of the capacity criterion, as I understand it, and trying to make sure

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that I took the right message from your discussions with Mr. Kelly earlier, you establish, in your case, an LOLH criterion and when you are forecasting that the number you expected to reach is higher than your criterion, you need to do something to bring that number down, whether that's creating new generation or shedding load or whatever, correct?
A. Yes, obviously, I mean, if it's 2.801, we probably don't be too concerned, but if it's 3 or 3.5, then basically that's a trigger that we need to start looking at new peaking capability on the system, in whatever form is most economic.
Q. Okay. And that's a standard way of managing this type of a hydraulic system or of an energy production system?
A. Pretty well any system, yes, any system that plans on an overall integrated basis would look at that, yes.
Q. Yes, okay. If we can look now at your Table 8, how much capacity do you need to meet the demands on the system in 2004?
A. Our peak requirements are 1602 megawatts and

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if you--I'm not going to do the math. I'm sure I'll tangle it up here, but basically we--and we have already said there's about a 16 percent reserve which basically gets us to the 2.8 LOLH. So it would be basically along the lines of 1602 plus 16 percent would be roughly the number.
Q. Okay.
A. You know, that is not an absolute, but that's the ballpark.
Q. Yes. And as I understand it, the 16 percent, and perhaps I'm wrong on this, is not the 16 percent a result of the 2.8 LOLH?
A. Yes, and we did file a report in IC-158 which actually talked about the relationship between the LOLH and the reserve figure. It used to be 18 1/2 percent, but there are a raft of factors that actually influence the actual percent, the load shape and so on, so it's 16 percent is the study that--is the relationship today between 2.8 and the -
Q. Yes. One of the factors that affects the percentage that that produces is the amount of capacity that you have in place, isn't it?
A. Yes, and the forced outage rates and their

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MR. HAYHES:
availability.
Q. Right. So -
A. It's not just a name plate rating. It's the whole.
Q. No, I understand that, but just at a matter of principle level, without getting into the numbers, the fact of adding Granite Canal would mean that your percentage of reserve would go down if your LOLH stayed the same, correct?
A. The actual reserve would actually go up. We would have more reserve because we added Granite Canal.
Q. You would have more reserve, but your requirement, your reserve requirement goes down as you add capacity, doesn't it, as a percentage of your total capacity?
A. The reserve requirement doesn't change that much as you add in the short term, it's basically, I mean, our requirement is 16 percent and by adding the Granite and the NUGS, we're basically right now at approximately--just a little less than 20 percent reserve. And typically systems are,

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you know, 15 to 25, even 30 percent reserve, depending on their situation.
Q. I understand that, but if you're targeting at 2.8 LOLH, and nothing else changes other than the addition of a couple of hundred megawatts of capacity, what does that do to the percentage reserve that is implied by 2.8?
A. The 2.8 percent reserve is--I'm sorry, 2.8 percent LOLH equates to about 16 percent reserve. In 2004, with our load forecast and the generation that's available, our reserve is actually just a little under 20 percent. So as you build generation, you will increase the reserve and then you will come down over time and then you'll presumably build new generation and you go up, you get sort of a saw-tooth thing sort of thing as you build the system.
Q. I don't think I'm getting an answer to the specific question in the sense of, as a matter of principle, if you maintain a 2.8 LOLH and nothing else changes, except that you add capacity to your system, does the required reserve percentage go up or down?
A. The required doesn't change, but what you

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actually would have would be actually a lower number. The required reserve doesn't change, you know, it's 16 percent. I don't under -
Q. Well if you have a thousand megawatts and at 2.8 LOLH, your reserve is 16 percent; hence, your reserve is 160 megawatts, correct?
A. Presumably, yes.
Q. Yes, okay. So if you then up that to 2000, if you reserve your--if your change your capacity to 2000, has your reserve requirement now gone up to 320 megawatts?
A. Only if your peak forecast load changed. If your peak forecast load goes up, then your reserve requirement would go up, you know, all else being equal.
Q. Yes, but if nothing else changes, if your requirements stay the same and nothing changes other than that you add capacity?
A. Then we would have overbuilt, the criteria was still 16 percent.
Q. The criteria is 16 percent or is it 2.2--2.8 LOLH?
A. No, well the criteria is 2.2, it equates to 16 percent. It equates to 16 percent reserve and that's the way the numbers come out. I don't

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think I clearly understand your question.
Q. Okay, just as a matter of mathematics, it seems to me that if a reserve of 160 megawatts is sufficient where you have 1000 megawatt capacity, and nothing else changes, your reserve, 160 megawatts, should be the same if you add 1000 megawatts of capacity and hence, you're still at 2.8 LOLH, but your percentage is now down to 8 percent? Can you explain to me what's wrong with that?
A. I think we're not on the same wavelength at all, I apologize. But when we plan a system, we plan for our loss of load hours of 2. 8 hours. Obviously as you build generation that you will have some impact on the actual LOLH that you would calculate for that situation. If were today and let's assume this was 2004 and if you go to Table 8, we have a loss of load hours of 1.1 hours. If we were to, for whatever reason, put in a new plant, even though the load did not change, there was no reason to do it, that calculation would decrease, you know, and the amount of reduction would be dependant upon the type of plant that you build, its forced outage rate,

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MR. HAYNES:
its capacity factor, its availability and they all influence the number. So that number would reduce, but the criteria would not change.
Q. No, the criteria is still 2.8.
A. And the amount of reserve that we would have on the system would increase substantially if you add a generation that you didn't need, for instance.
Q. No, I understand that, and my question is not directed toward the actual reserve that you would have, but the required reserve as a percentage of existing capacity to meet 2.8. And it seems to me that if you increase your capacity and change nothing else, that percentage has to go down?
A. Putting it that way and maybe I misunderstood for the last ten minutes, yes, because it's just math, you just have a--you need "X" amount of megawatts, 300 over a larger number, if that was the discussion, I apologize.
Q. That's where we were trying to get to, okay. All right, so the reserve is a number of megawatts and that happens to be a certain

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percentage of your existing capacity?
A. Yes.
Q. Yes, okay. So to get back to where I was, if nothing else had changed and the only thing that happened on the system was the addition of 224 megawatts of capacity from Granite Canal, then the percentage of the reserve that you would require, would go down, correct?
A. Yes, the megawatts didn't change much, but the percent, yes.
Q. Okay, and that's one of the things, I mean, it's not all of it, obviously, but that's one of the things that results in the 18.5 coming down to 16, correct?
A. And the load shape, you know, there's several factors that go into it.
Q. Yeah, but this is one of them, the fact that there is additional capacity on the system?
A. Yes, you'd have to look at where you are at some point in time.
Q. Okay, all right. So in 2004, what you require to meet your load forecast, your peak load forecast, is 1602 megawatts, plus your 16 percent reserve, correct?
A. That's more or less it, yes.

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Q. Okay, and what you have available is 1919 megawatts, correct?
A. That's correct.
Q. Okay, and the 1602 plus 16 percent is less than 1919, correct?
A. That would be correct because the LOLH is 1. 1 and not 2.8., yes.
Q. Yes, exactly, okay. So at the present time, you are capable of producing more megawatts than you need to meet your load, correct?
A. Yes, that's correct, and that would be a normal--as you build a system, that would be a normal event in any system.
Q. That will happen from time to time?
A. It will happen continuously.
Q. Yeah, but at this stage, you not only have more capacity than you need to meet your load, you also have more capacity than you need to meet your criterion of 2.8 LOLH, correct?
A. Yes, and that would be typical for any integrated system whereby you build plant in, you know, blocks that are--you can't continuously build a system on a marginal basis.
Q. No, no, I completely agree with you.

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A. So that's normal.
Q. Now just look at--let's look at the energy side. Your forecast for 2004 shows that you need to have available 8,504 gigawatt hours, correct?
A. Yes, that's correct.
Q. Okay, and your current capability, on a firm basis, is 8,706 gigawatt hours, correct?
A. That's correct.
Q. Okay. So you have the ability, at this stage, to generate more energy than the load that you are required to meet, is that correct?
A. Yes, that's correct, that's the energy balance on the far right.
Q. Okay. So in your discussion of Tuesday with Mr. Kelly, he referred you to the evidence of Mr. Bowman and Mr. Osler and I'm just trying to give you the transcript reference here. At page 4 of the transcript of October 21st of 2003, actually you should go back to page 3 and at line 7, he quotes from the evidence of Mr. Osler and Mr. Bowman, and your answer is, "No, I don't think what we have in service is in excess of what's required to meet the loads, given our criteria that we operate by."

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GREENE, Q.C.:

Now, you just told me that you have more capacity than you need to meet your LOLH, you have more energy than you need to meet your requirements for energy, why is it that what you have in service is not in excess of what's required to meet the loads, given the criteria you operate by?

A. You cannot economically expand the system to, as you need one megawatt or you need one gigawatt hour that you build one megawatt and you build one gigawatt hour. You build it in increments that are economically viable and optimize the time. So, you know, you cannot go in--well, you can do it if you want, but it would not be prudent or reasonable or economic to go in and build the Granite Canal for 27 megawatts and 100 gigawatt hours when the resource can provide you so much more, so -

Q. No, I'm not suggesting that at all and I'm not suggesting there's anything devious or wrong in this, it's just that at the present time you do in fact have more capacity and more energy capability than you need to meet the load in 2004?

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A. There is a small amount there which will carry us for a few years, yes.

Q. Yes, okay.

A. But I would not suggest it's "over built", it would be the normal way that you would expand the system.

Q. No, I understand exactly what you're saying and I don't think we used those words, but as matters stand now, it will be 2010 before there is a violation of your LOLH criteria, correct?

A. In 2009 the energy balance would be a very, very minor deficit and in 2001, the LOLH would be exceeded.

Q. Yes, okay. If we could look for a moment to your Schedule 14? This relates to the issues of growth that we talked about in terms of the percentages. From 2003 up to 2011, would you agree with me that other than in the last couple of years, 2010, 2011, the increase in the number of megawatts that you foresee having to meet is less than 10 megawatts in any year?

A. Well I think in one year it's 11, but more or less.

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Q. It's 11 in 2010?

A. Yes.

Q. But up until that point, this -

A. There are very small increases in the demand growth, yes.

Q. Okay, and looking over on the energy side, generally speaking we're looking at not much more than 50 gigawatt hours of growth in any year?

A. More or less, yes.

Q. And it's for that reason I asked you to do the calculation leaving out the effect of Voisey's Bay, so we come down to a .6 percent growth rate over the next 9 years, shall we say?

A. That's correct and on the energy requirements.

Q. The number you gave us this morning. In that context, Mr. Haynes, do you not feel that this is a particularly valuable time for Hydro to be looking at Demand Side Management's tools, given that a saving of a 40 or 50 megawatts off the peak could account for four or five year's load growth?

A. If you shave 45 or 50 megawatts off the peak and you do not affect the energy in any great degree, I mean, you have to look at the whole,

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I mean, it is a, obviously any reduction or conservation efforts will be a plus for the expansion of the system. If you slow it down, it's a lower per unit for power to all our customers.

Q. And on the energy side, the growth is fairly small as well?

A. Yes, .6 percent, it's not great, not big.

Q. So would you agree that this is a particularly good time then to be pursing Demand Side Management issues?

A. It would be--I'm not sure about Demand Side Management issues, it certainly would be an appropriate time to--it would be an ideal time to curtail the growth of electric heat or hot water systems. I don't think that you would actually get a lot of people to convert, but on new construction there would be some merit into slowing that down, yes, because it would actually slow--our projections of the load forecast are based on, you know, a fairly high proliferation of electric heat and then, as Mr. Wells has said, that is the choice of consumers and it is a fairly big element, other than Voisey's Bay hydromet facility is a

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MR. HAYNES:
significant driver of the load growth in our system.
Q. Thank you, Mr. Haynes. Those are my questions, Mr. Chair. Mr. Seviour will now address the plant assignment issues.
CHAIRMAN:
Q. Good morning, Mr. Seviour.
MR. SEVIOUR:
Q. Good morning, Mr. Chairman. Good morning, Mr. Haynes. Mr. Haynes, it's my happy task to get into plant assignment matters with you and I wonder if we could turn up your exhibit JRH No. 3, and if you could turn to page 23, please? And Mr. Haynes, could you read the first sentence under the heading "Conclusion"?
A. "Based on this review of the value of the Great Northern Peninsula generation and transmission assets and of the value of the Doyles/Port aux Basques and Burin Peninsula transmission assets to the Island Interconnected System, Hydro proposes a revision to the guidelines for the assignment of plant."
Q. Perhaps I can get you to stop there. In every

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general sense, can you outline to us what the revisions proposed by Hydro for the assignment of plant are today, compared to what they have done in the past?
A. If you go back a number of years, if you go back prior to the last hearing, the generation on the GNP was assigned common. We had proposed in the last GRA to make the transmission on the Doyles/Port aux Basques system and the GNP, as well as the Burin to be common as well because of the interconnected generation. In the Board Order P.U.7 that was not accepted and we were asked to go back and undertake this study to review the generation and transmission of all of those systems, which we have subsequently done, and the significant change that we're asking for or that we are seeking in this filing, as we think we have amply demonstrated, is that we do not propose to include the GNP transmission as common, but we do strongly recommend that the generation plant under GNP be considered as a common assignment because it benefits all customers.
Q. Thank you, and that's the one significant

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department on plant assignment that is made from the submissions made in P.U.7 hearing.
(10:30 a.m.)
A. Other than the changes because of Granite Canal and the other things which are generally, I don't think are in dispute, our filing--our GRA that we have filed for this particular hearing does not have the GNP generation as common, but we are proposing to incorporate that in our final filing.
Q. I want to come to that in just a moment, Mr. Haynes, but at this point for the assistance of counsel and the Board, I would like to focus on the guideline issues. You're the one who has presented the guidelines in your evidence as to the appropriate principles whereby there would be common plant assignment and specifically assigned plant judgments made, and in fact, I think you're the one who makes those recommendations for Hydro. So I understand the outcome of the proposal and I understand the change that's been proposed by Hydro in this GRA, but I want to turn for a moment just to the issue of the guidelines that underlie those recommendations and that

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change. And perhaps it would be useful at this point to turn up P.U.7, page 112. And as I understand it, the second and third paragraphs that appear on this page relates to the approach that Hydro took before this Board in 2001 in plant assignments, both in respect to generation and transmission. I just wonder if you could read for the record the third and fourth paragraph to kick off this discussion, please?
A. Starting at "Newfoundland and Labrador Hydro has proposed"?
Q. Yes.
A. Okay. "Newfoundland and Labrador Hydro has proposed in this Application that generation and associated transmission assets on the GNP be assigned as common, consistent with the Board's 1996 recommendations. IC-215 described the guidelines that Newfoundland and Labrador Hydro has proposed in order to apply the Board's '96 recommendations consistently across the Island Interconnected System. In its guidelines, NLH is proposing that in situations where transmission and terminal station equipment connect a single customer

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MR. HAYNES:
and remote generation to the grid, that the transmission and terminal equipment would be assigned common, if, under any normal operating scenario, the output of the remote generation can be delivered to the 230 kV grid. " IC-215, page 3.
Q. And perhaps I can just stop you there, and Mr. O'Reilly, if we could just bookmark that page and come back to it in a moment, but here we're dealing with the transmission and terminal station equipment assignment, and I wanted to flip back to your page 18 of your JRH 3 exhibit, if I could, to compare that guideline with what in fact is being proposed in this hearing? And under the heading 4.1 "Transmission Allocation Guideline", I understand the italicized part of that paragraph to represent the current proposed guidelines that Hydro seeks to apply in this hearing with respect to the assignment of the transmission and terminal station plant?
A. Yes, I believe that's correct, yes.
Q. Perhaps you might just want to read the context of it, I want to be sure on this Mr.

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Haynes.
A. Yes.
Q. And just for the record, would you read that please?
A. "The following facilities will be assigned as common plant: all of Hydro's transmission and terminal station plant that connects a single customer in generation or voltage support equipment that is of substantial benefit to more than one customer."
Q. Thank you, and Mr. O'Reilly if we could flip back to page 112 of P.U.7? So again, the paragraph that's in the center there is the one you just finished. The principle of assignment to common--referring to the last two lines, if under any normal operating scenario the output of the remote generation could be delivered to the 320 kV grid, that no longer is relevant to this discussion, is that correct?
A. No, we have not looked at it that way, we have looked at the substantial benefit and I think the distinction is under transmission assets.
Q. Sorry?
A. The distinction is on the transmission asset,

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the generation is still of substantial benefit to all customers and basically what we are proposing is the transmission may not necessarily be so.
Q. And maybe we can deal with generation by asking you to read the second paragraph that I initially referred you to, which starts, "NLH further declined"?
A. "NLH further declined the guideline by putting forward a test that if under light load conditions the combined generation of the radial line exceeded the radial load, the assets will be assigned common. This test would apply to radio systems on the Island and in addition to the assignment of the GNP assets to common, result in reassignment of the Doyles/Port aux Basque's system from Newfoundland Power specifically assigned to common and confirm the existing assignment of the Burin Peninsula to common."
Q. Thank you. Mr. O'Reilly, again if you could hold your place on that, we could go back to, in this case, page 23 of Mr. Haynes' JRH 3, and I'm going to ask you to read the definition of "common plant" that appears on

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that page?
A. "Common plant is defined as plant that is of substantial benefit to more than one firm customer. Costs for common plant are assigned to all customers of the system. The following facilities have been assigned as"--
Q. That's enough, I think it's just the principle I wanted to bring before the Board, Mr. Haynes, thanks. And Mr. O'Reilly, if we could get back to page 112? And the difference between the common plant assignment for generation that is found in the present Application, compared to the one in the paragraph we just read, we've omitted the test that if under light load conditions the combined generation on the radial line exceeds the radial load, the assets would be assigned to common. So that test is no longer the relevant test, is that correct?
A. That's correct.
Q. And are we to take it that by replacing the tests that you see for generation and for transmission and terminal station assignment in P.U.7, with the substantial benefit test, is that perceived to be a higher threshold in

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MR. SEVIOUR:
your view?
A. Can you just repeat that, I'm sorry.
Q. We've seen a change in the two transmission and generation assignment principles or tests or approaches that we've seen used by Hydro in the 2001 and the present hearing and I'm asking you if the current test which moves to a substantial benefit test for assignment of plant to common, is that seen by Hydro to be a higher standard than which was used in 2001?
A. I think you have to answer the question from--separately for transmission and generation. For generation, the criteria is--the results are the same. I guess at all generation, whether it's connected into the radial line or if it's in the middle of the 230 kV system, is used and useful and of substantial benefit to all customers. The transmission line test is, I mean, I guess the allocating plant is not a "science", there are a lot of flexibility of interpretation and history and so on. And the test that we have proposed in the last hearing was a lot less subjective in the sense that you did the test, it either passed or failed,

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so it ended up common or whatever. In this particular case, we look at the whole and it's a bit more subjective in the sense that you consider the size of the generation and so on. So it's less onerous, I would think, it's less specific, a bit more subjective now than it was in the past.
Q. It calls for the engagement of more judgment and consideration, is that fair?
A. Yes, and you would consider the whole transmission system and the generation location and the history.
Q. Okay. And we'll come to that in just a moment, but do I understand you to say that any, in principle, applying the substantial benefit test for common plant assignment purposes that any generations that interconnected to the grid would, in fact, be of substantial benefit to all customers that are serviced by that grid?
A. You would have to temper it by how long it takes to get it on and the availability to the system. I don't think you'd get down into, you know, some very small generation that somebody could actually put on for, you know,

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through some exceptional effort, but by and large, most of the generation or basically or all the generation that is assigned and considered in our calculations are either remote controlled or have operators in the immediate area who can actually do that fairly quickly, whether it's us or Newfoundland Power or whomever.
Q. So, there are judgment exercises that need to be brought to bear on the question of whether or not generation plants should be assigned to common, even if its interconnected to the grid for the province. Is that what I can conclude?
A. Yes, and the reason that I said that is because there are other generators that are out there and, you know, customers that are two or three tiers down and so on, which are not part of the exercise and they are remote, if you--not remote, but they are not generally available between our Control Centres or between, for instance.
Q. Just before leaving this discussion of principles and guidelines, if I can take you back, please Mr. O'Reilly, to page 23 again.

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And could you read the guideline respecting specifically assigned plant for the record.
A. Specifically assigned plant is defined as plant as a benefit to only one customer, cost for a specifically assigned plant are assigned directly to the benefitting customer.
Q. And finally I want to turn back to the beginning of this page, the second sentence, where we're talking about the revisions to the guidelines for the assignment of plant and you say, "these revisions reflect the requirement that each component of plant be assigned to customers in a fair and equitable manner". And I wanted to get your thoughts on that particular requirement that you referenced in your evidence that the plant assignment be done to customers in a fair and equitable manner. How does that principle apply to the guidelines that we've just looked at for the assignment of common plant and specifically assigned plant?
A. I think that--I shouldn't say I think--that it's our, it is our view that, for instance, the generation is of benefit to everybody. Therefore all customers contribute to its

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MR. HAYNES:
operation, maintenance, et cetera. For facilities that are of benefit to only one customers, be it a transmission line or a transformer and there is not benefit to any other customer, that is specifically assigned. It does not mean to say that you cannot have common plant that is behind this specifically assigned asset, such as a transmission line because the generation, as we've shown in the report, is usually useful for everybody's benefit.

Q. And we'll come to a discussion on that in just a moment. I guess I'm still at the level of principle, Mr. Haynes. And I'm trying to get a sense, in terms of the approach that's taken and these assignment issues. Is it fair for us to conclude and the Board to understand that in making assignments of plant, there must be an overriding principle that the assignment be made to customers in a fair and equitable manner as your evidence seems to state here?

A. Yes.

Q. And is that a fundamental principle of plant

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assignment, in your judgment?

A. Yes, it is.

Q. Thank you. I want to finish in this discussion by just stepping back a second. You're an electrical engineer by profession and that's, I think, the tenor of most of your evidence here in the past couple of days, is that correct?

A. Yes, I'm an electrical engineer.

Q. In terms of the plant assignment exercises, do I understand that this is something that is done by your department or is this done by your department in conjunction with other departments and/or executive members in Hydro?

A. The primary review of the plant assignment is initially done in System Planning. They basically design the system and so on and they are quite involved in the--not necessarily in the allocation of plant, but in designing the system to meet the customer needs and in the best position to asses its value, if you will, you know, and who benefits.

Q. And, of course, the Systems Planning people report to you?

A. They do.

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Q. And is that primarily an engineering analysis, a function analysis?

A. Primarily engineering is--the System Planning department do a lot of technical studies on load flows and so on, as do the Operations people obviously, have a good feel, if you will, for the way the system operates. The Planning people would have been most involved in the actual design of the system and the justifications for lines and generation and whether generation should be installed. You know, a lot of the remote generation, obviously, is historical, it was installed for a particular time. And as we interconnect systems, it is now of benefit to everybody.

Q. In the process of coming to recommendations to the Board in this hearing for common assignment or a specific assignment, does Hydro consider the cost implications to customers who may be affected common plant assignment?

A. We are conscious of the cost, but when it comes down to the philosophy and the fair and equitable treatment, that's an outcome of the results. It's not a--it's obviously a

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consideration, but it does not actually change whether it should be or whether re recommended a common or assigned. We try to stay--I shouldn't say we try, in our opinion, we try to stay pretty pure on that. It's either it isn't or it is not a benefit and the cost implications, they obviously fall out of that.

Q. So, if I understand your view of the process correctly, then this is a systems analysis, an engineering analysis to determine whether, by application of the principles we looked at, a piece of plant should be common or specifically assigned without regard to the cost impact on customers?

A. We do not--that does not play in any major way from the point of view of where we assign--where we think a plant should be assigned. It's basically based on benefit. Do they benefit and therefore, the cost of service would actually allocate the cost from there.

Q. So, the assignment based on a fair and equitable manner or fair and equitable principles approach does not, in your view, really extend to an assessment of the costs impact to customers on common or specific

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MR. SEVIOUR:
plant assignments?
(10:45 a.m.)
A. I would say no, that is a separate issue.
Q. I wanted to started with the GNP assets and talk briefly about them. I understand from P.U. 7 that these were interconnected in 1996 at a cost of approximately thirty one and a half million dollars. Is that consistent with your understanding?
A. 1996, if I recall, the dollar sounds right, but I -
Q. Maybe we could just turn that up for the record, it's page 110 of the P.U. 7 and the first paragraph there, I think, that we see a statement on the fourth line, third/fourth line, "the GNP interconnection was completed in '96 at a cost of $31,418,995.00." You accept that?
A. Yes.
Q. Thank you. Can I turn up RH 3, page 5, please Mr. O'Reilly. Thanks, can we get the whole screen on the--thank you, that will be fine, Mr. O'Reilly. I just wanted to begin with understanding what we're dealing with in terms

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of the assignment issues for GNP. And as I understand, we're dealing, the top left hand corner of the page, with three diesel plants and one hydro plant with an aggregate capacity of 15.1 megawatts for the GNP transmission. Do I have that correct?
A. That's correct.
Q. And for the GNP interconnection, these are the transmission lines and associated stations. We have a total of eight transmission lines, is that correct?
A. Yes, that's correct.
Q. And the voltages are as they've been set out. I think you already mentioned that in 2001, Hydro recommended the assignment of both generation and transmission as common. Now, that recommendation was not accepted by the Board and I just want to begin this discussion by returning to the Board's finding and disposition on that point and that's found at P.U. 7, pages 112, 113. Perhaps the bottom of page--can I--yes, that's perfect, Mr. O'Reilly. I want to read to the record or have you read to the record, the disposition of the Board in 2001 on this issue. And

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perhaps start at the very top of the page where it says, "the Board has insufficient".
Q. "The Board has insufficient evidence to accept NLH's proposed change in assignment of GNP assets to common. While the GNP generation can exceed the radial load under specific low load conditions, it is not clear that this scenario would actually provide any benefit to the Island interconnected customers since this is not when the generation will be needed by the system. IC 128 shows that the annual generation from GNP assets has constituted, on average, less than three percent of the GNP annual radial load since interconnection with the St. Anthony and the Roddickton diesel plants operated only for plant and forced outages".
Q. That's fine, thank you. And in terms of the percentage of average generation from the GNP assets, I'm going to take you to another percentage there, in the finding, was three percent. I'm going to take you to IC 87 NLH. And as I understand it, Mr. Haynes, this exhibit will allow the calculation of the percentage of annual generation of the average

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annual generation compared to the average annual load for the GNP. Am I correct in my conclusion that I can undertake that exercise with this exhibit?
A. Yes, the total generation and the annual load on the GNP are the two columns on the right.
Q. And by my math, Mr. Haynes, when I took the average of total generation, the second last column against the average of the annual load in the last column, I got figures which yielded a 2.7 percent figure. In other words, that the annual generation from GNP assets for the period '97 to the end of 2002 was on, average, actually less than 2.7 percent of the GNP average annual radial load. And my figures, just for the record on that were an average total generation of 1363.5 megawatts divided by an average annual load of 52,104 megawatt hours. I'll leave with that--does that sound about right?
A. It sounds reasonable, yes.
Q. Okay. And in referring to the year 2002, the figure was, in fact, even less than that reflected just for 2004, a use or a generation from the GNP assets of about 2.4 percent of

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MR. SEVIOUR:
the GNP load for that particular year. So, in fact, the three percent figure which the Board referenced in its P.U. 7 judgment, if you accept my math, is now in fact, less than it was in 2001. Subject to my math being correct, do you agree with that?
A. Subject to your math being correct, yes.
Q. Thank you. Now, the Board's direction to study the value of GNP assets to the island system, that is JRH 3 and that's the exhibit we've been looking at.
A. That's correct.
Q. And is this your exhibit, your document you've created?
A. It was created through my division, through Production Division.
Q. But you take responsibility for it?
A. I do.
Q. And a conclusion, as you've mentioned, is that the generation should be assigned common from GNP, but the transmission should be assigned specifically to Hydro rural?
A. That's correct.
Q. RH deals, at one point, with the issue of

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whether or not it's appropriate to treat generation differently than associated transmission for assignment principles, are you aware of that?
A. Yes.
Q. And Hydro concludes that this is fine, this is okay in principle, is that correct?
A. We have no difficulty with, as I mentioned a few minutes ago, that we do not, following this review, we do not propose or think that because a generation asset is common, that the interconnecting transmission must be common. They can be treated separately.
Q. I'd like you to take the Board to the basis for that conclusion and I think it's found at pages 19 and 20 of your exhibit RH 3. And for the record, I wonder if you could read what I understand to be Hydro's position on starting with "there are two key factors".
A. "There are two key factors to consider in determining if generation and the connecting transmission and terminal station assets could logically be assigned differently. Planning basis, the application of generation planning criteria as outline previously does not

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consider the location of individual generation assets on the system. The only consideration at this stage of the planning process is that the generation assets must be capable of delivering capacity and energy to a system and thus, the system be capable of utilizing that capacity when needed. The process of planning the transmission system focuses on the ability to maintain acceptable voltages, reliability, stability throughout the system. Transmission facilities must be adequate to connect generation to the grid and to serve the requirements of customers connected to the grid. Generation is not assigned to specific customers and a manner in which it is dispatched is depended only on the cost and system loading considerations".
Q. I think that the discussion concludes in the paragraph on the next page and perhaps for the record, you can read that as well.
A. "The cost of service, treatment of similar assets providing Newfoundland Power with a demand credit, particularly for the thermal generation acknowledges the benefit that these assets bring to the interconnected system, ie.

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they are of common benefit to all customers. Many of these generation assets are located well within Newfoundland Power's service territory with a connecting transmission and distribution lines owned and paid for by Newfoundland Power's customers. Therefore, this treatment of Newfoundland Power's thermal generation assets in the COS which has been in place since the 1970s would support the position that transmission assets need not necessarily be allocated in a same manner as remote generation assets, they connect to the interconnected system.
Q. Perhaps conclude with the final paragraph?
A. "The conclusion drawn is that remote generation and the connecting transmission and terminal station assets could logically be assigned differently in the COS. Further, in their final submission to the Board in the 2001 GRA at page 32, the Industrial Customers agree that an inconsistency would not exist were the GNP generation assets assigned differently-- GNP generation and transmission assets assigned differently".
Q. Thank you, Mr. Haynes. Now, can you confirm

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MR. SEVIOUR:

to the Board that Hydro's recommendations with respect to the assignment of generation and transmission for the GNP are similar to the recommendations made with respect to the Doyles/Port aux Basques system.

A. Yes, they are. The transmission assets on the GNP, we recommend to be assigned to Hydro rural. The transmission assets, although its Port aux Basques, we recommend to be assigned to Newfoundland Power, the generation on the GNP, we recommend common and the generation on the Doyles/Port aux Basques would be included in the credit arrangements or the calculations for Newfoundland Power.

Q. So, they're really two systems where you've got recommendations from generation to be assigned common and transmission to be assigned, specifically assigned.

A. In essence, yes.

Q. So, they're two applications of this principle that we just discussed.

A. Yes, and they are, you know, smaller amounts of generation basically on radial lines.

Q. And just to conclude on this point, are you

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aware of the EES report and the recommendations made by the Board's consultants?

A. Yes, I've read the report.

Q. And perhaps we can turn that up, Mr. O'Reilly, it's page 4 of EES report. And if you could just scroll down. I'm sorry, I'm at page 4, in the summaries, perhaps you could scroll-- there we go. Thanks. In the fourth bullet, the fifth bullet, the summary of EES's recommendations, they discuss the assignment and they say GNP Doyles/Port aux Basques and Burin Peninsula assignments should use a consistent assignment methodology for the generating and transmission facilities. And detailed study has found great benefit to all customers on the Island interconnect system from the generating resources and therefore, assigned these resources as common. The methodology used to assign these associated transmission facilities should be similar. The common system cannot get the benefit of the generation resources without the transmission facilities. So, I understand EES to be recommending that however the approach

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is undertaken, that the generation should be assigned in the same methodology or the same manner as the transmission. Do you understand that to be the case?

A. That's EES's recommendation, yes.

Q. And we'll have a chance to discuss that with them, but can you confirm that Hydro's position and Hydro's recommendations respecting plant assignment that are found in your exhibit RH 3 and in your evidence have not changed by reason of EES recommendations?

(11:01 a.m.)

A. No, they have not. We don't share that view. I could, from an overall system planning perspective, a small example would be that if we had the--if we needed to install, for instance, through our examination and our studies that we needed a ten megawatt peaking plant some place and the easiest thing to do from the point of view of keeping this clean and simple would be to install it at, say, Hardwoods or Stony Brook or whatever. When you look at the whole system and you look at a radial line and the GNP, Doyles, Port aux Basques, Burgeo or whatever, then you would

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actually cover off a couple of our reliability targets by dispatching that generation to a radial system. You do provide them some reliability and back up and you still meet your LOH criteria. So, we're quite comfortable that what we have proposed is sound and reasonable.

Q. Thank you, Mr. Haynes. Mr. Chairman, I'm just about to undertake a new area. I'm in your hands as to whether this would be an appropriate time for -

CHAIRMAN:

Q. I think it would, Mr. Seviour, yes. Thank you very much. We'll reconvene at 11:30 a.m.)

(BREAK - 11:30 a.m.)

(RESUME - 11:30 a.m.)

CHAIRMAN:

Q. The young men are still here. They'll be commended.

HUTCHINGS Q.C.:

Q. Still awake, Mr. Chairman.

CHAIRMAN:

Q. Mr. Seviour, when you're ready, please.

MR. SEVIOUR:

Q. Thank you, Mr. Chairman. Mr. Haynes, I wonder

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MR. SEVIOUR:
if we could begin by discussing the GNP transmission assignment, and I want to take you to JRH-3, page 20, which deals with Hydro's recommendation on that point, and under the heading "Proposed Transmission Assignment" could you read the section that begins "GNP transmission assets" for the record?

A. "GNP transmission assets. The GNP assets clearly follow the assignment guideline associated with the connection of a single customer, Hydro Rural, and the remote generation or voltage support equipment to the Island grid. Prior to 1996, transmission on terminal assets on an GNP up to and including Bear Cove terminal station were specifically assigned to Hydro Rural. An examination of the rationale for the 1996 expansion of the transmission system to Interconnected previously Isolated St. Anthony Roddickton system clearly indicates that the transmission system was constructed for the benefit of customers on these Isolated Systems. The generation assets on the GNP, which were

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originally constructed to serve the Isolated System, as a result of the interconnection now serve as a reserve capacity to the Interconnected System. While a benefit to all customers, these generation assets are not of sufficient magnitude, in Hydro's opinion, to justify an assignment of the GNP transmission assets to common, given the dominant use of the transmission system in serving that customer group. Therefore, while cost assignment is a matter of judgment with many issues and no absolute answer on balance, Hydro's interpretation of the guidelines would result in a recommendation that the GNP transmission assets be specifically assigned to Hydro Rural."

Q. Thank you, and does that mean that applying the principles or the guidelines that we earlier looked at, that we can conclude that in Hydro's view, the GNP transmission is not of substantial benefit to the grid?

A. The transmission, yes, that's correct, it's not a substantial -

Q. And the reason that it's not of substantial benefit to the grid is because the GNP

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generation is not of sufficient magnitude?

A. No. The GNP generation, 15.1 megawatts, is of sufficient magnitude to be a benefit to all customers, but the transmission connecting is primarily for the purpose of Rural. The generation is of use.

Q. Yes. But I understand your conclusion that the transmission is not to be assigned common because it's not of substantial benefit to the grid is because the generation that's interconnected by that transmission is not large enough?

A. It's not a significant number. It's 15 megawatts.

Q. Yes.

A. But it is of benefit to all customers.

Q. No, I understand your position on the generation, Mr. Haynes. Don't misunderstand me. What I'm just trying to get a fix on and to be precise about it, is the basis for your conclusion that the transmission is not of substantial benefit to the grid, and if I misunderstand you, correct me, please, but I would understand that the reason that the transmission is not of substantial benefit to

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the grid and should be assigned to Hydro Rural is because the generation on the GNP that is interconnected is not of a sufficient enough magnitude.

A. That is one of the primary reasons, yes.

Q. Is there another reason?

A. The transmission--the justification for interconnecting the St. Anthony Roddickton system was the subject of a cost benefit--you know, a net present worth evaluation, which basically justified the interconnection based on the government, the Federal government grant, and it was an economic thing to do for Rural and so on. The generation was interconnected to the system at the time and is of benefit, but the transmission is of no significant value per se to the common system.

Q. That's an historical circumstance?

A. It's historical, yes.

Q. Yes. Thank you. Thank you for that. I'm going to ask you to turn to page 24 of JRH-3 now and ask you if Hydro's position with respect to the assignment of the GNP transmission to Hydro Rural is also consistent with the Hydro Rural sub-transmission

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MR. SEVIOUR:
guideline for assignment of plant? Perhaps you can read that for the record and then address the question.
A. "The NPIC sub-transmission -
Q. No, sorry, the Hydro Rural sub-transmission.
A. I'm sorry. My apologies. "Hydro Rural sub-transmission is defined as all transmission and terminal station plant serving only Hydro Rural rate classes." So it's consistent.
Q. And is Hydro's conclusion and recommendation of assignment of the GNP transmission to Hydro Rural also consistent with that assignment guideline?
A. We believe so, yes.
Q. And that isn't expressed in the passage we just looked at, but that's another reason, is it not, for the assignment of the GNP transmission to Hydro Rural? Is that fair?
A. Yes, that's correct.
Q. Thank you. And just to close the loop on this, for the record, your approach with respect to the transmission on the Doyle/Port aux Basques section of the Island Interconnected System is pretty much the same

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as the conclusion and approach taken with respect to the GNP?
A. Yes, it -
Q. Is that -
A. - it's similar. There's only one customer, Newfoundland Power, and the generation is not of significant magnitude to warrant the transmission being common.
Q. And perhaps you could just read the disposition at page 21 respecting Doyle/Port aux Basque please?
A. The Doyle's/Port aux Basques. "Similar to the GNP, the transmissions assets of the Doyle/Port aux Basques system fall under the assignment guideline associated with the connection of a single customer, Newfoundland Power, and remote generation or voltage support equipment to the island grid. As well, like the GNP transmission assets, the primary purpose of the Doyle's/Port aux Basques transmission assets is to provide service to Newfoundland Power customers on that radial system. This position is further supported in the previous Board decisions in which these transmission assets were

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specifically assigned to Newfoundland Power. The generation assets also located on that radial, while of benefit to all customers, are not of sufficient magnitude, in Hydro's opinion, to justify assignment of the transmission assets to common, given the dominant use of the transmission system in serving that customer group. Therefore, on balance, Hydro's interpretation of the guidelines would result in a recommendation that the Doyle's/Port aux Basques transmission assets be specifically assigned to Newfoundland Power."
Q. And the Doyle/Port aux Basques generation is a magnitude similar to that of the GNP?
A. Yes, I believe it's 15.8 megawatts and GNP was 15.1, I believe it is.
Q. I wanted to conclude on this area by discussing the implications of assignment of the GNP transmission line to common, and I appreciate that that is not Hydro's recommendation, but it is a recommendation that appears to flow from the Board's expert's report that we looked at a moment ago, and I wanted to address it, for the record, because

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there's not much before the Board on that implication. Can I ask, Mr. O'Reilly, to turn up IC-345? And this IC, as I understand it, asks for the identification of the costs in the test year 2004 Cost of Service for the GNP transmission line, which under Hydro's recommendation is assigned to Hydro Rural. Are you familiar with this RFI?
A. Yes.
Q. And this indicates the calculation of the average plant in service and average net book value for those assets, and puts them in the range respectably of $73,120,423 average plant in service and $58,950,414 for average net book value. Is that correct?
A. Yes.
Q. And these reflect the asset values which presently are assigned to Hydro Rural in the 2004 Cost of Service? Do I have that correct?
A. That would be my interpretation, yes.
Q. And if, in fact, the EES recommendation was to be followed by the Board, the result would be those costs being assigned to common, for the purposes of the 2004 test year Cost of Service?

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(11:45 a.m.)
A. I would have to assume that that was specifically for--wouldn't include the distribution, so yes, that would be the correct answer, interpretation.
Q. And I looked through the record on the weekend to try to determine if I could gauge the implications to the Industrial Customers of that shift in cost assignment and I couldn't find anything on the record. In fact, I think there was an RFI directed to EES which went--could not be responded to because there was not enough on the record. I did want to take you to a document, IC-180 Revision 1, filed in the 2001 General Rate Application. It's a document that the clerk has distributed to counsel earlier this morning, and I'm not sure if the Board has the document. Ms. Newman, perhaps you could indicate to me whether or not that's the case?
MS. NEWMAN:
Q. Yes, it has been circulated, and we would identify it as Information Item No. 16.
MR. SEVIOUR:
Q. Okay. And has the witness been provided with

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a copy of IC-180?
A. Yes, I have.
Q. You have it. Thank you, Mr. Haynes. What I understand this IC to relate to, in the 2001 GRA, is the implications to the Industrial Customers and Newfoundland Power of the change in the assignment of the 138 kV 66 kV transmission lines and associated terminal station equipment connecting the GNP generation from Hydro Rural to common. I guess my first question is, that equipment that's referenced, does that cover all of the GNP transmission equipment that you've described in JRH-3?
A. I believe that to be the case, yes.
Q. Thank you. And in 2001, the cost implications for the two customers were respectably, a decrease of $2,000 in costs for Newfoundland Power and an increase to the Island Industrial Customers of $1,458,000, and my question is whether or not you know if these figures correctly reflect the implications for Newfoundland Power and the Island Industrial Customers for the 2004 test year, as opposed to the 2002 test year?

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A. I wouldn't be the best one to answer it, but subject to Mr. Banfield providing clarification, I doubt very much that the numbers are identical, but I would suggest that the order of magnitude is approximately the same.
Q. Okay. I'm wondering as much as the EES recommendation has come to the Board late and there has been little evidence on this, if I could have an undertaking to provide the updated IC-180 for the current test year, 2004? (Undertaking)
A. We will--I assume that time will permit it to be done. I'm not sure how long it would take, but that would be done by our rates and customer service people.
Q. Thank you, Mr. Haynes. Thank you, I'm going to move on to a discussion about generation. I think we're finished with the transmission for the moment, Mr. Haynes. I understand the basis for your recommendation that the GNP generation be assigned common because it assists the system reliability and because it may defer the need for new capacity? Is that a fair description of -

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A. It could defer the need for a new peaking plant or to address our LOLH, yes.
Q. And my first question is a very general one, Mr. Haynes. I'd like your reaction to this. Is there not an inconsistency in saying that the Great Northern Peninsula generation is too small to require GNP transmission to be specifically assigned, but it is large enough to be of substantial benefit to all customers of the grid?
A. No, I don't think there's an inconsistency. It is 15 megawatts. It's, in the context of the GNP, it is, you know, aligns fairly well with the GNP load or it's less than the actual peak, but with respect to the total Interconnected plant that Newfoundland Hydro has available, it still would affect the--it could have impact on the LOLH calculation, so therefore, it is of meaningful value.
Q. So is it the impact on the LOLH criterion that allows you to conclude that within the guideline, the GNP generation is of substantial benefit to all customers?
A. The generation, yes.
Q. Okay. What is Hydro's--or let me begin, does

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MR. SEVIOUR:
Hydro have a practice, Mr. Haynes, with respect to the decommissioning of thermal generation on an Isolated System which is subsequently interconnected?
A. Typically, the economic benefit, I guess. Most of the systems that we interconnect, with the exception of the GNP, which was a large generating capacity, are usually very, very small systems, and the practice has been such, you know, for instance, Monkstown and La Poile, which had been very small systems, that we would actually take that plant out of service because it's very small. The operating maintenance costs are significantly high, and the physical location of staff would not be as amiable to getting the equipment back, you know, in service in less than an hour, for instance.
Q. And can I ask, Mr. O'Reilly, to turn up IC-104? And my interest is really in, I think, the second page of the document, which I understand to be an application by Newfoundland and Labrador Hydro to decommission the Roddickton wood chip and

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diesel generating stations. Are you familiar with that application?
A. Not thoroughly familiar, but I am familiar.
Q. Yes. And this is an application in 1999, as I understand it, that was made by Hydro in relation to the decommissioning of those particular facilities and from what I understand your general evidence to be, that wouldn't be inconsistent with the past practice in other isolated systems which were interconnected?
A. But that case is not exactly the same. For instance, if we were interconnecting, you know, one of the smaller isolated areas. That was a five-megawatt steam plant which had a significant operating and maintenance expense and the economics to keep that going were just not there. As well, if you were maintaining it only to meet your LOLH, you just--you don't put a button and start a steam plant. For instance, Holyrood takes two days to get a machine, 48 hours plus to actually fire it up and get it going. So it would not have the same value, and that's basically why it was abandoned.

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Q. The cost benefit analysis wasn't there?
A. It wasn't there.
Q. As I suspect it is not there in most of the generating stations that -
A. On the very small stations.
Q. Yes, okay. And I want to take you to paragraph 5 of the application, which is on the next page, Mr. O'Reilly, which states "the Roddickton diesel plant has not been required in order to provide power to the Roddickton area since the interconnection of the formerly isolated St. Anthony Roddickton system to the Island Interconnected grid." And then, paragraph 6, perhaps you could read that for the record, Mr. Haynes? I may have a--yes, just read it out for the record, please.
A. "Normally, upon interconnection, Hydro decommissions all diesel generation capacity which supported a formerly isolated area. The St. Anthony Roddickton area electrical load is situated at the end of a long radial transmission line. In this case, Hydro has decided to retain the 8,800 kilowatts diesel generation at St. Anthony as a backup generation for this area. The capacity of

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this plant is sufficient to meet at least 75 percent of the forecast peak for the area through 2008, and Hydro has determined that this is a reasonable and prudent amount of backup capacity for this interconnected area."
Q. Now what I get from this application and Hydro's proposal to the Board is a couple of things. One, that the Roddickton diesel plant was unnecessary in 1999, in the eyes of Hydro, because it hadn't been required to provide power to the Roddickton area, and I think we see that in paragraph 5 of the application?
A. It did--following the hearing though, it was retained. There is a diesel plant at Roddickton, two 850 kilowatt units.
Q. I understand that -
A. Okay.
Q. - to be the case. Thanks for that clarification, Mr. Haynes. I was going to ask you about that. But what I'm getting at is in the mind of Hydro, at least in 1999, I am concluding that Hydro's perspective at that time was that Roddickton diesel plant was unnecessary?
A. That was our view.

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MR. SEVIOUR:

Q. Thank you. And the other thing I'm getting from the paragraph 6 is that St. Anthony was perceived by Hydro to be backup generation for the area, at that time. Is that also a fair conclusion?

A. That was a part of the rationale for retaining the diesel in the area, because a long radial system.

Q. And take a moment, if you wish to, but when I read the application, I see no reference in the application, again trying to understand what was in the mind of Hydro at the time, to a need to retain either of the diesel plants as either system reserve or for peaking requirements for system capability.

A. I haven't read that report in some time, so I--if it's not there, I assume that it wasn't there.

Q. You know, no games.

A. I have not reviewed it.

Q. I've read the application. I don't see any reference to that.

A. I accept that.

Q. Thank you. Mr. O'Reilly, could we turn up

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P.U. 7 for the moment, and page 113, if we could come to that? I want to look at the bolded section in that page. The last sentence, starting at the middle of the paragraph, says "the Board will require NLH to undertake the necessary studies and analyses to support the value of the interconnection of the GNP assets to the grid, including:" and I broke this down in two ways, "including: an assessment of the impacts on system reliability" which I think we've talked about, "and number two, the conditions and operating scenarios under which the GNP generation would be of benefit to the operation of the Island Interconnected System." And I think we can go back to JRH-3 for a moment, if we may, page 10, and these criteria that we find on page 10, the planning criteria relating to the energy and capacity standards. These are essentially the reliability part of that analysis that the Board directed in 2002?

A. That is a system reliability. The capacity would be the key consideration for the diesel generation, 2.8 hours per year.

Q. And these are part of the reliability

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analyses, as I understand it. Is that correct?

A. That would be part of that exercise, yes.

Q. And if I can take you just--I don't want to spend much time on material that was covered already, but I just want to set up a couple of inquiries I have. Table 3.2 or 3-2, which is at page 11. We've seen this a couple of times. This is the same as your Table 8 in your principal evidence, I think.

A. That's correct.

Q. And this reflects that there will be a capacity issue in 2011 and an energy issue in 2009. Is that correct?

A. That's correct.

Q. I think you've said elsewhere in your evidence that the energy balance issue in 2009 is not of significant enough consequence to be concerned about and that, in fact, there would be no need to add any capacity before 2010. Is that correct?

(12:00 p.m.)

A. For 10 gigawatt hours, that would be our approach.

Q. Yes. Move to Table 3-3, which is the next

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page, page 12, and this shows the scenarios respecting the base case, which is the current system, I think, in its forward-looking, you know, capacities for both demand and energy less the various radial systems we're talking about?

A. That's correct.

Q. And focusing on the GNP, this would reflect that if you took the existing plus committed system less the GNP, which is the third column of the table, out of the mix that your capacity issue, from the base case situation, would advance from 2011 to 2009 without GNP?

A. That's correct.

Q. And your energy balance concern would remain at 2009, the concern? Is that correct?

A. The actual table does not present the energy issue for that particular case. The energy number of 61 is the GNP, Doyle's and Port aux Basques removed.

Q. So we must assume that the energy case is also still a 2009 issue?

A. I would suspect it hasn't changed.

Q. And I think that there is a--I won't turn it up, but there's IC-398 deals with that and

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MR. SEVIOUR:
confirms it, for the record. I wanted to take you to IC-288. I'm sorry, I have that incorrectly written down. It's--bear with me just a moment. Yes, it is 288, Mr. O'Reilly. And this is the hypothetical extrapolation of the table we just looked at, which reproduces all figures assuming the availability of 46 megawatts of Interruptible B power, and if I understand the analysis with respect to the GNP, if you introduce the availability of Interruptible B power to the Table 3 analysis, you have a situation where the capacity violation occurs not in 2009, but in 2010, for the loss of the GNP?
A. That's correct.
Q. And the energy, I guess, is not really shown here?
A. No.
Q. It's only shown for an aggregate of the three radial systems? Is that right?
A. That's correct.
Q. Okay. So that if the Interruptible B was available and you add that to the analysis, it would have deferred the capacity issue, at

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least with respect to the removal of GNP, by a year?
A. It would have changed that trigger date from 2009 to 2010, that's without the GNP but with the Interruptible B.
Q. Yes. Thank you. I take you to IC-399. And as I understand this IC, Mr. Haynes, it refers to the hypothetical situation of the GNP load and generation being disconnected from the Island Interconnected System; in other words, it reflects the scenario of pre-interconnection GNP transmission and generation?
A. Yes.
Q. Are you familiar with this -
A. Yes, I am.
Q. - this IC. And as I understand the reply, if you look at page 2 of 2, in this scenario, there would be no energy or capacity problem until the year 2112?
A. That's correct.
Q. And does this analysis also indicate that applying the energy and capacity criteria that you'd used in your JRH 3 study, the Island Interconnected System would be more reliable

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without the GNP interconnection?
A. No, I don't think it relates to the Island system being more reliable, you've added transmission assets, you've added generation assets, you've picked up more load. It impacts the timing of action required to maintain that reliability and criteria, but it doesn't actually make it more or less reliable, not on a reliability basis per se.
Q. Okay, I'm going to take you to the testimony of Intergroup, the Industrial Customer's experts, because I want you to react to their assessment of this evidence and if I could ask Mr. O'Reilly to pull up that, it's at pages 32, 33. We'll start at the bottom of page 32. And at line 35 of the evidence, could you just read that passage going onto the end of the first paragraph on page 33?
A. On page 32 or 33?
Q. 32, starting at line 35.
A. This is from Osler and Wilson. "As an example of the issues that must be addressed, the material in IC-399 is instructive. In particular, this response indicates the Island Interconnected System, LOLH and energy balance

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that would arise if the GNP were not interconnected to the Island Interconnected grid, comparing these results to Haynes' Table 8, indicates that on a net basis the GNP radial transmission line, including both loads and generation, have a net adverse impact on the Island Interconnected System."
Q. Perhaps I can stop you there. Can you react to that ascertain by our experts that there's a net adverse impact on the Island Interconnected System by reason of the GNP radial transmission line?
A. It has affected the timing of the next generation source when you look at the whole Island Interconnected System, it does not consider generation expansion requirements on the Isolated System and so on, so it's--it has an impact on the--it obviously has an impact on the LOLH calculation because you remove generation and load.
Q. And that's not a positive impact, in fact, it's--I mean, sorry, that is a positive impact in that it defers the violation of the LOLH criterion, is that correct?
A. It affects that, but the interconnection to

MR. HAYNES:
the Great Norther Peninsula system was based on the net present value analysis and was, in our view, the right thing to do. It had economic benefits to the overall operation of the system.

Q. And I think I understand that, but perhaps I can get you to move on in the passage at line 2, if you could continue on in the discussion from Intergroup.

A. "But for this radial line being interconnected, the Island LOLH would improve to .7 hours per year, in the test year, from 1.1 hours per year in Haynes' Table 8 and the energy balance likewise would improve. Also notable the requirements for future generation additions to the Island Interconnected grid would be delayed to 2012 from the currently forecast 2010. On balance, this type of information indicates a reason for concern from the IC respective that cost for the GNP assets will be assigned to the IC Cost of Service, even though these costs only arise as a result of a project that has a net adverse impact on the IC service quality.

Q. And apart from the answer you just gave us with respect to the Pre-Interconnection Study, do you have any other reaction to this passage and this position of our experts?

A. I think the word quality may be--I don't think it affects the quality of service, i.e. the reliability that we provide. It may obviously impact the costing, as would the big driver in 2012. The fact that we go from a figure of 2.4 to 7.4 and of an energy balance of 28 to minus 415 is largely driven by another potential Industrial Customer, that's where the Voisey's Bay load forecast comes into play.

Q. Thank you, Mr. Haynes, I wanted to give you the opportunity to respond to that. The next question I had relates to your discussion of the valuation of the generation, the remote generation and that's found at pages 13, 14 of JRH 3. And in this passage of your report, I understand that you're trying to ascribe some dollar value to the generation that's under discussion, is that correct? The estimated value of generation assets?

A. Well, yes, what we had indicated it was

impossible to put a dollar value specifically on the--those assets bring to the Interconnected System, but we looked for an indication of the value they bring to the costs further on, yes.

Q. I wanted to take you to the bottom paragraph starting "However", and could you read that for the record please?

A. "However, it is possible to get an indication of the value that these assets bring to the Island Interconnected System through an examination of the costs that would be incurred if Hydro were required to purchase a similar amount of peaking capacity today. Based on cost estimates for a new simply cycle combustion turbine, the levelized annual cost of new peaking capacity, coming around line of 2004 is in the order of $100.00 per kilowatt per year. This yields an annual evaluation of approximately 6.5 million per year, for the total of 64.5 megawatts generation assets on a GNP, Doyle's and Burin Peninsula radial systems. As indicated in Table 3.3, the removal of these assets from the existing system capability would advance the timing of

peaking capacity requirements by 7 years, from 2011 to 2004. This implies a simple evaluation of the generation assets of some 45.5 million. Due to the avoidance of capacity additions in that time frame, it follows that the presence of these assets on a system has had a similar impact on past decisions."

Q. And my purpose again in taking you to that is to give you an opportunity to react to the comments of our experts, the InterGroup people at pages 33 to 34 of their report, and starting at line 35, page 33, they have a response and discuss the analysis that's found--that we just looked at. And perhaps you could read commencing at line 35?

A. "The reasoning raises two serious concerns. First there is no basis to suggest that any costs would have to be incurred to replace this generation in 2004 if it were not already in service. As with the GNP generation, the Island Interconnected LOLH only increases from 1.1 hours per year to 1.4 hours per year. This is still well below the target maximum of 2.8 hours per year; second, the ascertain that

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MR. HAYNES:
the 14.7 megawatts of capacity would have to be replaced at a cost of 1.47 million to the system is incorrect. Hydro has previously contracted with Abitibi Stephenville for 46 megawatts of capacity over three times the capacity made available to the GNP generation, for a cost of less than 1.47 million per year, for essentially the same function."

Q. Now I'll get you to stop there. And my purpose in taking you to this was to give you an opportunity to react to that passage, and in particular, the ascertain made by InterGroup that the availability of Interruptible B hasn't been considered in your analysis and how do you respond to that?

A. No, it was not considered, the Interruptible B contract was entered because it was a significant number of years between LOLH criteria violation, if you will, and the energy balance. It's also not the same product. The Interruptible B had severe limitations on the months it was available, on the hours of the day and the notice period and so, they are not--it was a useful product, it

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served a useful and valuable purpose, but in the context of the generation that we have available right now, which is already interconnected which is used and useful, there was no reason to consider extension or entering a new contract with Interruptible B products from any sources.

(12:15 p.m.)

Q. Thank you. I wanted to turn to the second part of, I guess, the test or the study assignment that the Board made in 2002 in P.U.7 relating to the conditions and operating scenarios under which the GNP generation would give benefit to the operation of the Island Interconnected System. We looked at that a moment ago from P.U. 7, remember they wanted the reliability assessment and also an assessment of the conditions and operations--operating scenarios. And I understand and I won't cover the ground in any detail, that there really are two examples that Hydro cites, one of an actual commissioning and one of a testing of the GNP to assist in system management issues in the evidence that's before us, prior to the filing of this

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Application in any event. Am I right that there's two incidents, one is a testing incident and the other is an actual commissioning incident?

A. There is, when I see it on that, I don't recall the number offhand, but it does indicate that we have used it for the purpose that we intended; however, it is tested on occasion to ensure it's available and we have used it since, in 2003.

Q. Now I'll take you to IC-87 and just to copperfast on this point, I think we looked at this earlier, but starting at line 10?

A. Yes.

Q. Do you have that sir? Line 10, as I understand it, this describes in perhaps the greatest detail in the material before the Board, the incidents of use of GNP generation. Perhaps you can just read that, starting at line 10 to the end of the IC, so that we have it in its greatest detail?

A. "The St. Anthony and Roddickton Diesel Units operated for only planned and forced transmission and line outages during the period of 1997 to 2000. On January 31, 2002,

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the load on the Island Interconnected System reached an all time peak. All hydraulic facilities in the three units at Holyrood were at near peak capacity. A loss of any of these generators would require an operation of standby generation, including the GNP diesels. In preparation for such an event, the St. Anthony diesel plant was tested to ensure its availability. The plant operated for 110 minutes, during which time the approximately 8536 kilowatt hours of energy was supplied to the system. On January 30th, 2003, the St. Anthony diesel plant was brought on line to aid in a system restoration following the failure of a lightening arrestor at Oxen Pond and a subsequent trip of the generators at Holyrood. The plant operated for 75 minutes, providing approximately 6150 kilowatt hours of energy to the Island Interconnected System."

Q. And these are incidents that each occurred prior to the commissioning of Granite Canal, is that correct?

A. Yes, that's correct.

Q. And can you comment as to the likelihood of the requirement of commissioning the GNP

MR. SEVIOUR:
assets for generation? In similar circumstances, had Granite Canal been commissioned before the incident described?
A. That's a difficult question to answer because it all depends on the situation. We have used the GNP generation since Granite Canal and the NUGS came on line to fulfil that role of trying to get our customer's load back.
Q. And I want to come to that in a moment, we'll talk about the September 18, 2003 incident and I fully accept that that's the evidence before the Board, but what I'm trying to engage for the Board's assistance is your view, as an experienced production person with Hydro, and what impact, if any, you feel that Granite Canal's availability may have had on the circumstances described in January 31, 2002, January 30, 2003?
A. It would all depend on the load situation at the time and what particular units were out of service. When, in that particular event, in January 30th, we basically lost the three machines in Holyrood, I believe, in which case that's Granite Canal, the gas turbines,

basically we would have to take everything in our arsenal to actually meet that load at that time; particularly when you lose 466 megawatts, we don't have that reserve and it's not an event that we--I shouldn't say we don't plan for it, we obviously do the best we can, but it's not an event that would be a common occurrence. And on that occasion, I would suggest that Granite Canal, the NUGS, all the gas turbines, all diesels would have been called into play because of the nature of the--just the volume of megawatts that we actually lost from the system.
Q. What was the volume and megawatts?
A. Well the particular item indicated that the three plants in Holyrood at near peak capacity, which would have been approximately 465, 466 megawatts, and if they were--I suggest they weren't necessarily on the pins, but you were at, at least 460 megawatts, 450, 460 megawatts that we had actually lost.
Q. And my colleague, Mr. Hutchings, asked you some questions about the September 18th, 2003 incidents and I'm not going to take you back through that, but the one thing I would like

to get from you is an undertaking to provide further particulars as to that particular event and the requirement of engaging the GNP transmission at that particular event. I'd like to know the time at which the generation supply occurred, the duration for which that generation supply occurred, the relevant capacity and energy that was engaged to assist at that time. (Undertaking). And I think that's relevant for the Board to know. And so, Mr. Haynes, is that something that you can get for me?
A. That information can be made available, yes.
Q. Thank you, sir. To finish up in this area, I wanted to confirm that I think as it is before the Board in IC-235, that the Great Northern Peninsula generation has, apart from the three examples we have just spoken about, operated 112 times for local load support since 1996? Is that what I take from IC-235?
A. Yes, that's correct.
Q. Thank you, sir. And do you know if that--this is an IC that was filed some months ago, do you know if that figure has changed?
A. In all likelihood it has changed by a few

things, any time that we have a transmission line outage or that we are responding to a, you know, a storm, wind damage or an outage, we would actually bring those into play for local support of load, as opposed to interconnected.
Q. And could you provide that updated figure please (Undertaking)?
A. Yes.
Q. Thank you. Mr. Haynes, is it fair to conclude from this review that the principle role of the GNP generation has been for back up or local support in the GNP area?
A. It has served that function, as well as serve the function of the Island Interconnected System by its calculation of the LOLH. It serves both purposes.
Q. And it served the Island's specifically, the Island's system on three particular incidents that we've canvassed in some detail and 112 plus incidences of the local support, as I understand the IC I just took you to, and my question is, is it fair to characterize the GNP generation's function and service principally as one of backup to the GNP area,

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MR. SEVIOUR:
as opposed to service to the grid?
A. It has served that role because of its location on the radial system, but it still contributes to the overall LOLH and that part of that calculation, but you're -
Q. So is it your evidence, sir, that there is an equal benefit to the grid and to the local area based on the actual service of the GNP generation since '96?
A. It's our evidence that the GNP generation serves a valid role in meeting our LOLH criteria and as well, it also serves the local residents because of the long radial line.
Q. I think we'll let the numbers deal with that. I just wanted to finish this area by taking you to IC-188, and as I understand it, Mr. Haynes, this table that we see on IC-88 (sic.) identifies all incidents from 1996 when Newfoundland Power generation was operated by Hydro's request for support of a grid, is that correct?
A. That's correct.
Q. And these are incidences in which Hydro has actually paid for peaking generation support

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to Newfoundland Power?
A. Yes, if we request--I'm sure that Newfoundland Power use it many other times for their own, you know, reliability purposes in their region when they're doing work, but whenever we request Newfoundland Power to run thermal generation, we do pay for that use.
Q. I wanted to speak briefly about the cost implications in this area, Mr. Haynes, and I wanted to take you to IC-277. This relates to the total of 1.4 million costs for Hydro's diesel generation on the Island Interconnected System for the 2004 Cost of Service. And in reading IC-277, together with IC-278, I have concluded and I would ask you to confirm, that the 1.4 million dollars related to the Hydro diesel generation, relates exclusively to the GNP diesel generators? Can you help me on that?
A. Yes, that appears to be correct. We do not have diesel generation in other locations of any consequence, other than the GNP. I believe that's in Schedule 2.
Q. And so that is the cost implications of the plant that's in service for GNP generation,

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excluding the mini hydro at Roddickton, is that correct?
A. That would be the--yes, that's correct.
Q. And to close the loop on the cost implications, can I get you to go to IC-233, and I think that as I understand this IC, which has directed the initial costs to the Industrial Customers and the implications for Newfoundland Power, the assignment of GNP generating assets to common results in an increase to Newfoundland Power of $11,830.00 and to the Industrial Customers of $191,136.00 after rural deficit and revenue credit allocation. And can you confirm that?
A. Yes, that is correct.
Q. And why is the implication of this cost reassignment of such a minimal impact to Newfoundland Power, do you know?
A. I think if you were to look at the actual calculation where it was done you would find that before the deficit allocation the cost to Newfoundland Power would be considerably higher, because Newfoundland Power customers will pay--when you assign the transmission line common, it would not be a part of the

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rural deficit. If it's assigned rural, then the cost of the operation of the GNP would be a part of a deficit and Newfoundland Power customers would pay through the deficit, which is says there on line 9.
Q. Because Newfoundland Power has got to pay for this whether or not it's assigned to Hydro rural or to common?
A. Newfoundland customers will pay in either case, yes, Newfoundland Power customers.
Q. Mr. Haynes, can you confirm that the GNP generation is insufficient to satisfy the full GNP load in normal operating conditions?
A. Yes, I believe that's correct.
Q. Thank you. And finally, taking you to IC-234, I just wanted to confirm that if there was a reassignment of the GNP generation assets to common, that this has an implication of an additional $44,986 in return on equity to Hydro?
A. That is a calculation done by Mr. Banfield's group, but to my knowledge that is correct because it's a return equity that we would be earning as well.
Q. I'm going to finish my cross-examination by

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MR. SEVIOUR:
talking about the Burin transmission line. And I think that your recommendations are that the Burin transmission lines, unlike the Doyle's/Port aux Basques and the GNP transmission facilities are to be assigned to common?
A. Yes, that is correct, as they are now.
Q. Now, there are no Industrial Customers on the Burin Peninsula, is that correct?
A. There are no Industrial Customers, no.
Q. The transmission facilities in question do not serve any of the Industrial Customers of Hydro, is that correct?
A. No, they don't.
Q. Can I get you to turn up page 6 of GRH-3 which is the map showing the Burin lines? We see them depicted in green running down from Sunnyside, transmission line 219 and 212?
A. Yes.
Q. And the Paradise River hydro station which is Hydro's 8 megawatt station is on transmission line 212?
A. It's connected to 212.
Q. And we see some additional Newfoundland Power

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generating facilities at the boot, the foot of the peninsula, is that what we're seeing on the map?
A. That's correct. The hydro stations and their gas turbine.
Q. Now, as I understand the evidence, the transmission line 219 is a newer transmission line, is that correct?
A. Yes, that's correct.
Q. And in terms of the relative valuations for Cost of Service purposes the transmission line 219 is a much more expensive transmission line than 212?
A. I don't know the numbers, but I'm quite sure that you're correct, the newer line would be the higher per kilometre cost.
Q. Okay. And I won't take you to it, but in IC-334 the average plant of service for transmission line 219 is shown to be $14,199,201 versus transmission line 212 which is at an average plant in service valuation of $5,105,326. Does that sound about right?
A. Yes.
Q. Now, can you confirm that transmission line 219 was not constructed to service the

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Paradise River plant?
A. No, it would not have been constructed to service the Paradise River plant, per se. It was constructed to service the Burin Peninsula system.
Q. And can you confirm that it's not a necessary transmission line to interconnect Paradise River to the grid?
A. Paradise River could have been connected to the grid without it, but it does serve a role. It's an alternate route for Paradise River and the other generation on the Burin Peninsula. But it would not have been required solely for Paradise River.
Q. It certainly wouldn't have been constructed or designed as a backup, for example, to be able to supply Paradise River generation to the grid?
A. Not for 8 megawatts, no.
Q. No. And--thank you. The Hydro rural customers on the Burin Peninsula, how are they served, which line services them?
A. They are served from, I believe it's Monkstown. There's a--they are low voltage lines that come off one of the substations

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there. I think -
Q. And of the two transmission lines, are they served by both or by only one of the transmission lines?
A. Well, you could say that they're served by both because if the line TL-212 is out of service between Paradise River and Sunnyside, the power would actually go down rather than come back up. So, you know, both lines actually serve all the customers on the Burin Peninsula.
Q. Okay. Physically in relation to the two lines how are the Hydro rural customers supplied, are they supplied physically from distribution from 212 or from 219?
A. You know, transmission TL-219 basically is from Sunnyside to Salt Pond with no intermediate station, so it would come off the stations along TL-212.
Q. So physically the Hydro rural customers are supplied from 212, is that right?
A. The shortest physical route to the system would be through 212, yes.
Q. I was trying to get a sense, then, from Hydro's evidence, as to what was the principal

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MR. SEVIOUR:
basis for the proposed assignment to common of the transmission lines because there are two reasons expressed in the evidence and in your testimony before the Board, one being that the Burin transmission line service to customers, that's Newfoundland Power and Hydro rural, the second reason being that the transmission lines interconnect significant generation to the grid. Which is the principal driver of your recommendation?

A. Well, they are both drivers. The guidelines that we had established was that if it serves two customers, it would be common, two or more customers it would be common. And we interpret or we feel that the significant generation on the Burin Peninsula is a lot more significant, if you will, than the GNP in Doyle's/Port aux Basques. So it's a combination of both.

Q. Okay. And my question arises partly because in all of the evidence that's before this Board in dealing with the recommendation of assignment to common the first reason cited is always the fact of two customers being

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serviced by the transmission lines. But in your evidence of the 21st of October, and perhaps I can get Mr. O'Reilly to pull that up in fairness to you, I took it to be the generation concern which was the dominant driver of the recommendation. And I'm looking at page 21 of your evidence of October 21, 2003. And here you're addressing questions from Mr. Kelly about the assignment of the transmission lines. And at line 19 of page 21 you say, "So in the whole, we have proposed that the Burin Peninsula, because it serves two customers, because it has significant generation, and significant generation I think is the key that it should be considered common." And I want to, you know, ask you, do I take from that, that you see the interconnection of generation from the Burin Peninsula to be the principal reason for your recommendation that generation on Burin be assigned common?

A. It is a major reason why it should be considered common, but you -

Q. But you say here it's the key.

A. It is the key, it is 34, 35 megawatts and it

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is a major component of the generation that we have available.

Q. So the Board can look at that as the principal reason, can they?

A. I think so. But the guidelines that we've established also talks about serving two customers, so it's a balance. And in all Cost of Service or plant allocation is a balance of various reasons.

Q. And in the past when the Burin generation has been assigned to common, the generation has been greater on the Burin Peninsula, hasn't it?

A. There was an additional 15 megawatts of gas turbine generation that Newfoundland Power is moving to Bonavista Peninsula, yes.

Q. So there's been actually a decrease in the Burin's generation capacity since the last General Rate Application?

A. Yes. 14.7 megawatts, I believe, is the number. But as well, of course, the wind turbine is expected to go in the Burin Peninsula which will add again. But we feel that the 34, 35 megawatts is sufficient to justify its common allocation.

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Q. In terms of the cost implications here can I take you to IC-228? And this deals with the impacts on customer classes in the event that transmission 219 was assigned to Newfoundland Power. And on the schedule, column 6, my instructions are that the implications to the island Industrial Customers for the transmission lines being assigned common as opposed to it being assigned to Newfoundland Power represent $231,709. Would that be consistent with your understanding?

A. That's after the revenue credit, yes.

Q. And the same analysis with respect to IC-229, which relates to the implications of assignment to Newfoundland Power of transmission line 212. Again, in column 6 of the second page, the table in that exhibit, my instructions are that the cost implications to the industrial customers are $87,297?

A. Reduction, yes.

Q. I just wanted to put a hypothetical to you, Mr. Haynes. In the Burin transmission arrangements, if you took away transmission line 212, which I think you've indicated physically is the service source for the Hydro

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MR. SEVIOUR:
rural customers and is also the interconnection for the Paradise River to the grid, if you took that away and you're left with just the transmission line 212 and the Newfoundland Power facilities on the boot of the peninsula, how is transmission line 219 with 212 removed in that scenario different from the Great Northern Peninsula circumstance where you're got a long radial transmission line and remote generation?

A. The--one of the major things is the fact that the generation is so much more on the Burin Peninsula. It's a significant amount of generation, it's 34 megawatts today, possibly increasing by 25. I would--one caveat there is that given that you have a line going by, if we were to build Paradise River and there was a 138 kV line going by, we would have to actually cut into that line at significant additional cost as well, which would increase that component to--because you would be going into a 138 kV line and have to establish a terminal station and so on, which was--which would add to the cost, if you will, of common

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anyway.

Q. It take you to IC-339, please? And this IC asks Hydro to indicate the loads for peak in energy and revenues arising from service by Hydro on the Burin Peninsula. Separating sales to Newfoundland Power from sales to Hydro rural. And the figures are there and when we look at them and extrapolate the loads to customers, we concluded and it's been filed with our experts that 99.5 percent of the load and therefore the customers on the Burin Peninsula are Newfoundland Power customers and 0.5 percent of the load and therefore the customers on the Burin Peninsula are Hydro rural customers. And can you confirm that that's a fair analysis?

A. If it's 99.5 percent of the energy sales, I'm not sure about the number of customers, but the energy deliveries, those would be the right numbers, 99 and a half and point five.

Q. But that's consistent with your understanding is that in relation to Newfoundland Power's presence on the Burin Peninsula Hydro's presence is really negligible?

A. Well, it's a half percent of the energy

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deliveries are Hydros.

Q. And why does that situation remain as it is, why is there not a situation where Newfoundland Power is servicing all of the customers on the Burin Peninsula if there are so few or such little load being served by Hydro?

A. We have not discussed turning assets--you know, like changing the assets with Newfoundland Power, as such. Newfoundland Power does assist on emergency repairs and so on, but we have actually not exchanged assets. But they do contribute, we do work together to serve those customers.

Q. I think that there's a joint NP/Hydro report and study on what those common efforts are, and they're related to emergency service, as I understand?

A. Primarily emergency or switching, as well. They have some people in the area.

Q. But if I understand you correctly, there's no business initiative or consideration within Hydro of divesting itself of these very few Hydro rural customers on the Burin Peninsula or any discussions with Newfoundland Power in

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that connection?

A. Not currently. There was some discussion in the Energy Policy Review along those lines, but that was more of a larger issue. We have not had any dialogue with Newfoundland Power on these assets to any great degree.

(12:48 p.m.)

Q. Okay. I just had a couple of more questions to finish on this--finish period, Mr. Haynes, you'd be happy to hear. But I wanted to take you to page 124 of JRH-3. We're back to first principals now with the guidelines for assignment. And we looked earlier at the Hydro rural sub-transmission guideline which I think you told us was another basis for proper assignment of GNP transmission to Hydro rural. And then we have NP-IC sub-transmission. And that's defined as transmission and terminal station plant which serves both Newfoundland Power and an Industrial Customer but not Hydro rural and has an original cost of at least two percent of the total transmission and terminal stations costs.

A. Yes.

Q. And that's another guideline for assignment of

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MR. SEVIOUR:
plant which falls within the guideline to only Newfoundland Power and Industrial Customers. Is that correct?
A. That's correct.
Q. I wanted to give you the opportunity to react to a comment of our experts which is found at Tab H, page 3. And we're at page--page H-3, I think is at the bottom of the page, Mr. O'Reilly, it's Tab H, page H-3. It's a couple of--it's some of the second or third last line--last page in the whole document. There we go. Okay. Line 11 there on the page under the heading "Burin Peninsula Transmission Allocation." And our experts are commenting on the proposed assignment to common of the Burin transmission. Line 11 they say, "Hydro has proposed in Exhibit JRH-3 that the Burin Peninsula be assigned to common the same as in P.U.7 (2002-03). However, the primary basis for this recommended allocation appears to be that the line services both NP and rural customers. However, based on other tests for NP-IC sub-transmission assets, given that the system makes up a material asset value, it

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would appear that this factor would only lead to a joint NP rural allocation with no basis to assign any costs to IC." And I think in substance, what I take from the InterGroup advisors, the Industrial Customers is saying, well, look, why isn't the Burin transmission assigned as an NP Hydro rural sub-transmission allocation. Maybe you could respond to that?
A. There is no category as that at the moment, and I guess between that and the significant generation, we don't really think it is warranted to do that. I grant you, it is a small part of the load, but the generation is also--cannot be discounted in that decision.
Q. So, Hydro has never considered a hydro NP sub-transmission allocation or assignment of plant guideline of this nature?
A. Not in recent time that I'm aware of, no.
Q. Just on the wind power project, Mr. Haynes, can you confirm a couple of things for me? There currently is no power purchase agreement, is that correct?
A. We are negotiating a power purchase agreement.
Q. One has no yet been signed?
A. No.

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Q. And what about the financing for the project, is it place, do you know?
A. No, it would not be in--actually, the financing would not be--we would not finance the project. The project would be financed by the proponent. We would just be a purchaser.
Q. Yes, but to your knowledge, is there any financing in place for the proponent?
A. I really am not sure of what Newind has done to date. I would add that they, from the point of view of that, that they are--one of their partners is a corporation who has other wind turbine projects. So, I would not anticipate that being an issue from the point of view of them being able to finance the particular job.
Q. The physical interconnection for the wind power project, what transmission line will be utilized?
A. My understanding right now is that, well, it will be interconnected in St. Lawrence and the cost of the interconnection facilities to the existing system will be a contribution to any construction by the proponent to Newfoundland Power, in fact. It's connected in their

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system.
Q. Okay. So, it's not physically connected to TL 219 or TL 212?
A. Well, indirectly, but I'm not quite sure St. Lawrence would be a little bit further down there.
Q. My final question, Mr. Haynes, relates to your common plant assignment of the Coney Arm line and substation which is, I think, shown on Schedule 17 and I think that there's an IC filed on this, IC 226. The question is well, "why is the line and substation to Coney Arm assigned as common"? And the answer is, "the line and substation to Coney Arm is assigned common because it is a source of station service for the Cat Arm generating station and also connects the Rattle Brook generating facility to the system".
A. That's correct.
Q. Could you just elaborate on this? Has this been assigned common in the past cost of service?
A. Yes, I believe it has, prior to Rattle Brook because it is the primary station service supply for Cat Arm. So, it's a necessary

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MR. HAYNES:
component or addition--if you never had that, you would have had to have some, I don't know what the numbers are, but some significant cost at the Cat Arm station. It's also a radial line. So, if the line is out of service, you still need diesels or power supply to prevent freezing and et cetera.
Q. And I take it that this is not a change -
A. No, it's not a change.
Q. - proposed from previous assignment of that facility?
A. Yes, and the Rattle Brook would have had another rationale for that assignment.
Q. Thank you, Mr. Haynes. Mr. Chairman, that's the extent of my questions.
CHAIRMAN:
Q. Thank you, Mr. Seviour. Thank you, Mr. Haynes.
HUTCHINGS, Q.C.:
Q. Mr. Chairman, just before we conclude, there was a point that I asked Mr. Haynes on Tuesday about the production capabilities of Holyrood and while the word undertaking wasn't used at page 156 of the transcript at line 19, I

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understood that I was going to get a recalculation of the number. I explained to him at the time that I couldn't reproduce his 2996 number and he was going to recalculate it for me. So, I don't necessarily have to get that number right now, but just to note that that's outstanding.
GREENE, Q.C.:
Q. We had planned to provide that in re-direct or Mr. Haynes can do it now, but we are in the position to respond.
HUTCHINGS, Q.C.:
Q. Okay, as long as it's being addressed in re-direct, that's fine, Mr. Chair.
CHAIRMAN:
Q. Thank you. Good afternoon, Mr. Kennedy.
MR. KENNEDY:
Q. Good afternoon, Chair.
CHAIRMAN:
Q. There's some prospect, I think, discussed at the break about possibly finishing today. I don't know whether that's non-existent or that prospect still holds true. How long would you -
MR. KENNEDY:

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Q. I would say that's slim and none we'll get through and all done by 1:30. So, I was going to propose that I just continue and then if I'm not finished, just break at 1:30, if that's okay.
CHAIRMAN:
Q. If you could concentrate on the slim part, it would be good (Laughter). Thank you.
MR. KENNEDY:
Q. Yes, I always seem to get the woolly headed witnesses and woolly headed participants (Laughter).
A. There's no wool on my head, Mr. Kennedy (Laughter).
Q. Mr. Haynes, I wanted to talk to you about system planning, in general, as it falls under your division. And I thought that first I'd like to just have a chat with you about the Holyrood generating station.
A. Yes.
Q. And I notice from your pre-filed evidence that it indicates that, in your profile, that you received your Bachelor of Engineering degree in 1977.
A. Yes, I did.

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Q. And that's when you joined Newfoundland and Labrador Hydro as a graduate engineer?
A. Yes.
Q. Now, the next paragraph refers to the fact that you held a number of positions with Hydro including Instrumentation Engineer on the construction of Holyrood No. 3 generating unit.
A. Yes, that's correct.
Q. Now, as I understand it, when Holyrood was initially built, there were two units that were put in service in 1970?
A. Yes.
Q. And then there was a third unit that got added in 1974?
A. 1979/1980 time frame, No. 3 was built.
Q. Okay. Well, you need to update your website there. You website says 1974.
A. That may have been when it started, but it wasn't actually finished until--actually it was probably more line '77 was started.
Q. That's what was confusing me with the 1977 and then the indication that your positions were with No. 3. So, Mr. Haynes, when Holyrood was originally constructed in 1970 with these

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MR. KENNEDY:
initial two units, and I understand those two units were 150 megawatt units, correct?
A. That's correct.
Q. And then the third unit was a 150 megawatt unit?
A. That's correct.
Q. And then there was some changes made to your system which bumped up the mega wattage available from each of those units, correct?
A. Only from numbers 1 and 2. Number 3 did not have the ability to be upgraded in the same sense as units 1 and 2.
Q. Right, okay. So, originally, the total capacity of Holyrood was 450 megawatts and now its 490 megawatts?
A. That's the gross rating, yes.
Q. Right, okay. So, when Holyrood was originally constructed and put into service in 1970 with those 2 units, could you tell me from your experience in coming on board in 1977, what the purpose of Holyrood was at that point in time? What role was it supposed to serve in your system?
(1:00 p.m.)

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A. Well, there would have been a couple of roles actually. Primarily it would have, you know, there were probably three significant roles. One of them would have been a backup, if you will, to the Avalon Peninsula where most of the load was. And basically what had--when a system was initiated, we built a Bay D'Espoir generating station and there was two or three stages of construction for Bay D'Espoir and the Holyrood units 1 and 2 came along about the same time. And with the transmission system being built across the wilderness area and its reliability concerns et cetera, that that particular plant was back up, if you will. It also provided some voltage control capability, particularly in the winter. You would not be able to ship, you know, all the megawatts from Bay D'Espoir to meet the Avalon load without a lot--some voltage support equipment on the east coast and that would have also served that purpose. But I don't know the actual justification or the criteria, that was long before my day. And I don't know what the rationale was, but those would be, you know, major considerations at the

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time, when they were building the grid and anticipating a fair load growth, you know, expansion of electrical sales.
Q. So, are you aware then of when, at the time that the Holyrood generating station was brought on stream, was Hydro's firm energy requirements, were they able to be met through just the hydraulic resources that Hydro had at the time? Are you aware whether Holyrood was required in order to address that aspect of your system?
A. I'm not sure of the numbers, but I would suggest that the reserve that was in place when Bay D'Espoir and units No. 1 and 2 were commissioned would have been in excess of what it is today, but I don't know the numbers.
Q. But prior to units No. 1 and 2, was just the hydraulic resources up to that point sufficient to address your firm energy requirement. Are you aware of that?
A. I would suggest that it was, but there was a tremendous growth. The mandate of Newfoundland Hydro, when it was created, was to look after the rural ratification, to interconnect these systems so there was a, you

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know, a sustained and very--the .6 percent growth that we spoke about this morning would have been quite different at that particular time.
Q. So, I've seen it referred to sometimes, Holyrood that is, as, that originally conceptualizes as a winter peaking plant in that Holyrood was used to provide your capacity requirements, if you will, during the winter months when the load is higher than otherwise.
A. I think if you go back in time, the utilization of Holyrood in the summer months would have been a lot less than it is today. So, there may have been--you know, the operators at the time would still optimize on fuel price and so on or they would shut down at whatever occasion they could. The operating history in the last number of years is that we operate the plant more hours per year generally than, I would suggest, in the '70s or the '60s, mid '70s.
Q. Counsel for Newfoundland Power during his examination of yourself eluded to the fact that load patterns have changed and noticeably

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MR. KENNEDY:
during the '90s. And I guess I took it from that that it's indicative then of the fact that Holyrood itself is being used differently now, than it was in '80s and '70s?
A. Well, Holyrood is being used more in a sense that there are less summers months, there's weeks in the summer that we can shut down. But it's basically, where all our short term marginal energy come from is Holyrood and it is required for capacity in the winter.
Q. Sure. And I understood that, if I gather correctly, that Holyrood, in a way almost uses your base plant now, that it--except for this duration during the summer that it's used to provide your base load for the duration of the year.
A. It's a key component of a system, yes.
Q. So, in the case of your Hydro resources, for instance, you referred to the fact that you use your hydraulic produced product in order to address capacity constraints and that Holyrood itself is used to produced energy.
A. When we do the load forecast, for instance, for 2004, we look at our total energy

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requirements and we do what's called a hydro-thermal split. And so we basically do our load forecast and projections of Holyrood use based on that. And that is, you know, basically the hydro-thermal split is not revised every week, but the load forecast and load requirements are revised every week and we try to optimize the megawatt levels of Holyrood to be as high as we can while adhering to our other system conditions. And if we get an influx of rain, then we won't shut Holyrood down because we think it's a day or two, but if we see a week or a period of time that we can shut it down, then we will do that.
Q. During the winter period, just take for instance, as I understand it, you would normally operate Holyrood at as close to full capacity as you can?
A. We would make it as high as we can while looking at the overall economics, yes.
Q. Sure. And that the problem, as you said, is that if you run a system like Holyrood to the pins, as you described it, that it doesn't provide much leeway to address further

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capacity requirements or as you put it, voltage issues that may arise as a result of that, correct?
A. Yes, and frequency regulation, yes.
Q. And so that aspect of maintaining your system then shifts over to your hydraulic capacity. You use your hydraulic capacity as an add on, if needed, at the point that Holyrood is going flat out.
A. The variation of the loading on say, Bay D'Espoir over a 24-hour period would be quite varied compared to Holyrood. Holyrood may change some, but the Bay D'Espoir hydro plants would change quite a bit.
Q. Okay.
A. And we may shut down units and bring on units as required, but we would not treat Holyrood the same way.
Q. So, in that sense, is Bay D'Espoir and you hydro units that is the storage of water in the watersheds is, in that sense, treated as your capacity and that the water actually running through your system is what's providing the energy?
A. The--say that again?

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Q. Okay. Let's go to, let's take the example of a run in the river system. A run in the river is pure energy, no capacity.
A. Well, there is some capacity.
Q. Marginal or minimal amount of capacity.
A. Depending on the size of the plant, it all factors into the equation and into the -
Q. There's usually little or not storage that you can count on. So, it's mostly energy that you look at a run in the river system for.
A. There is a credit in the system to look after it, but it's not as use and useful from that point of view as a system with a lot of storage.
Q. Okay, but in the case of Bay D'Espoir, we have both capacity and energy provided through Bay D'Espoir, correct?
A. Most of our hydro plants have a fair bit of storage, yes.
Q. Right. And so, I guess what I was getting at is during your winter months, when you have Holyrood running at, you know, almost full capacity, that you're using your capacity in Bay D'Espoir in your other hydraulic to provide that extra capacity, if needed?

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MR. HAYNES:
A. Yes, but also, if you go back to Schedule 4, we also try to run not too far ahead of that, whatever line that is.
Q. The green line.
A. The green line, yes. We don't want to be too far ahead of that because risk spill.
Q. Right.
A. And then we obviously do not want to spill water.
Q. So, in the case where it looks like that may have been, you'd cut back on Holyrood production in order to produce more hydro energy.
A. Yes, we wouldn't keep Hydro at--I'm sorry, we wouldn't keep Bay D'Espoir at--I'm sorry, Holyrood at 150 megawatts or 170 megawatts or if we're going to risk spilling water.
Q. Right.
A. You know, we would--actually, it's the other way around. We would run it up on the pins to avoid spilling water. So, it's a balance between those two that we try to maintain.
Q. So, is it the case then that the character, if you will, of the Holyrood generating station

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and how it's used by Hydro has changed over the last couple of decades? It's gone from itself being used as, sort of, that peaking capacity filling requirement in your system especially in the winter months to now that capacity filling requirement that you have in the winter months being shifted over to your hydraulic end of your business.
A. I'm not sure if I would put it that way. I think the last twenty so years, I mean, we basically plan--we plan Holyrood to, particularly since the '90s, for 25 percent incapability factor to protect our firm. And it's a critical component of our portfolio. It's not--I don't think you can actually treat it much different. The way we load the plan is most due to economics. It's a critical part of the whole.
Q. Yes, so I guess, that was the next point is assuming for a moment that the way that Hydro utilizes the Holyrood plant has changed since this introduction in the '70s to today in the sense of how you use it in your system planning, your annual system planning, that that was--is it fair to say that that wasn't a

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policy decision, it was a changed brought on through a process that was driven from just your system factors?
A. I think as the system matured and as you start to, you know, interconnect the various areas and regions that that utilization increased and you became more of a mature system, if you will.
Q. Now, I just have some points I wanted to clarify about Holyrood again, itself, and it's been described that Holyrood is your marginal cost plant, correct?
A. In the short term, yes.
Q. Your short run marginal cost plant.
A. Yes.
Q. Okay. And I understand that that's because of the fact that there's a high variable in your operating and maintenance for the energy that is produced by Holyrood as compared to your other plants in the system?
A. Yes, but primarily fuel would be the main driver. It's primarily the cost of fuel.
Q. Right. Because the amount of kilowatt hour for energy produced by the Holyrood generating station at your proposed conversion factor of

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624 kilowatt hour per barrel works out to 5.13 cents per kilowatt hour, correct?
A. I believe that's the number, it was quoted.
Q. Okay. And that 5.13 cents per kilowatt hour is actually made up of a fuel cost which was 4.7 cents a kilowatt hour and then the rest is your O & M variable.
A. Yeah, there are fuel additives that increase with the amount--chemical use that increase with the amount of fuel.
Q. Which is .45 cents per kilowatt hour?
A. I believe that's the number.
Q. Okay. Now, reference has been made to the fact that Granite Canal has a--is able to produce energy at 5.5 cents per kilowatt hour to the bus bar, I believe is how Mr. Wells put it?
A. Yes, I believe.
Q. Okay. And are we dealing with apples and apples there in the sense that this 5.13 cents per kilowatt hour for Holyrood is at the bus bar?
A. I think the 5.3 cents at Holyrood, I don't think that number actually considered the capital cost of the plant whereas the figure

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MR. HAYNES:
for Granite Canal would have considered it, and there are no significant costs with respect to the water itself. Whereas Holyrood is primarily driven by fuel, I believe the variable O&M number was driven by fuel additives and chemicals and so on. Whereas Granite Canal was basically a function of the depreciation and interest and so on.
Q. Right. So in the case of Granite, that's the average annual energy production costs, 5 1/2 cents per kilowatt hour, correct?
A. There were two or three different numbers quoted, but that's the order of magnitude, yes.
Q. In the case of Holyrood, that's just your short run marginal, 5.13 cents. Do you know what the average annual energy production costs for Holyrood is, as proposed?
A. You mean considering capital and -
Q. Yes.
A. I think it's less than six. It's less than six cents, in that order.
Q. Now there's also the oddity, isn't there, that the less Holyrood is used, all else being

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equal, the higher your marginal cost is going to become for the energy produced at Holyrood?
A. Well, you would have a--obviously you have the fuel costs. You also have O&M costs, which change a little bit. You have employee salaries and so on. So the dollar per kilowatt hour would be--if you were to look at the actual cost of producing a kilowatt hour at Holyrood and look at the fuel, the O&M, et cetera, the fact that there are 99 employees, the less production, you know, you have the fuel coming down, you have the other costs going up.
Q. But your conversion factor usually erodes if you produce less energy at Holyrood?
A. Yes, because you can't get it up at these high efficiency points that we -
Q. So your short run marginal cost at Holyrood increases the less you use it?
A. Yes, I think last month or two months ago, we had 608 kilowatt hours per barrel because we were low.
Q. Mr. Haynes, intuitively, would you agree with me that your system is more expensive to run in the winter months, as opposed to the summer

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months?
A. Well, we're burning more fuel then. The maintenance activities will be toned back a bit because we're not doing overhauls and so on, but by and large, there is some increase in the day-to-day operating costs, particularly from a fuel point of view.
(1:15 p.m.)
Q. Would you agree that winter-driven capacity requirements are pushing cost into the system?
A. I guess the winter-driven--as the capacity or the demand increases, you would have to install more plant to meet that peak criteria.
Q. Traditionally, would you agree that Hydro's new plant requirements have been driven by capacity constraints more than energy constraints?
A. They're actually driven by both, but the major--you know, when we deliver most capacity, when we deliver most energy is in the winter.
Q. I was doing some calculations, Mr. Haynes, on what the per capita consumption of energy has been in the province for the period 1991 to 2001, and I started with the population of the

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province in 1991, and I got these from IC-113, and in 1991 we had 576,489 people and by 2001, that had dropped to 521,200 people. Okay?
A. Yes.
Q. And then I looked at the kilowatt hours sold for each of those years.
A. Yes.
Q. And this is all the entire province, Labrador and Newfoundland, because the population statistics included both. And then I just worked out a per capita consumption of kilowatt hours, and the per capita consumption in 2001 worked out to 13.21 kilowatt hours per person, and the per capita consumption--and I might be off by a magnitude. I'm not sure if I got my decimal place in the right spot, but it doesn't matter because I'm just going to compare the two of them.
A. Yes.
Q. The per capita consumption for 1991 I got to be 10.2 kilowatt hours per person. So it denotes an increase in the per capita energy use for the period 1991 to 2001 of 29.4 percent, which would be, on average, 3 percent a year.

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MR. HAYNES:
A. If that's the math, yes.
Q. Okay. And I did the same thing for your demand on the megawatt basis.
A. Yes.
Q. Peak weather adjusted. And I get an 18 1/2 percent increase in the per capita demand use for the same period of time, which works out to 1.85 percent per year. And I'm wondering, there's been a lot of testimony about the forecast load growth and forecast energy growth and the numbers that Hydro is using is, I think as you indicated just a few minutes ago, .8 percent for some of them or around the 1 percent level for your capacity growth and your energy growth?
A. Those figures were for energy growth. I didn't actually calculate the numbers on the capacity.
Q. Okay. But you'd agree with me clearly that in the last ten years, your per capita growth, at least based on those numbers, has certainly been much higher than one percent. That for the system purposes, the only reason your energy growth that you're seeing at the end of

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the day is that one percent per year is because there's been this drop in the population of the province?
A. Well, there are a multitude of factors that go into that particular forecast, the gross domestic product, the population is an input. The personal disposable income is an input into that long-term planning forecast as well. But I mean, your numbers on the individual per capita consumption, I have no doubt they're correct, and that's a statistic that's common in many jurisdictions, in Canada particularly.
Q. Which statistic, the 3 percent?
A. The fact that the per capita consumption of electricity is increasing, as it has increased substantially over the last number of years.
Q. Okay. That's a question I had. Just assume for the moment that I'm correct that your per capita consumption of electric energy has been at an annualized 3 percent for the last ten years. Do you know how that compares to the national growth rates or the rates experienced in other provinces on a per capita basis?
A. I don't know the detail, but I do recall reading various things, that Canadians are the

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highest per capita users of electricity in the world or in the northern climates, and there's lots of reasons put forward as to why that's so, because of the northern climate and so on, but I'm not surprised at the number, but I don't know the specifics for the other jurisdictions.
Q. There's also, I guess, wheels within wheels, there's also some significant growth being experienced in your Rural Isolated sector of your business, correct?
A. Particularly in Labrador.
Q. And PUB-3, page 52, provides some of that, just for the Panel's assistance. So I guess, Mr. Haynes, given that there is again a looming capacity or energy issue that Hydro's going to have to deal with -
A. Yes.
Q. - by constructing new plant, and given that that issue is arising as a result of these increases in energy use and demand requirement on a per capita basis, can I ask you why Hydro hasn't, other than the HYDROWISE Program targeted towards the rural customers, why it hasn't implemented demand side management or

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conservation programs aimed directly at the average user in the Province of Newfoundland and Labrador?
A. I guess we have not taken it upon ourselves, I guess, to target the customers of Newfoundland Power with respect to that. We do have the programs, the HYDROWISE Program. We do look at demand side management in the isolated areas. But the biggest component of the load growth on the Interconnected System is actually--is primarily the all-electric customer of Newfoundland Power. We have a very small number and the penetration rate of electric heat in our interconnected areas is not as high as--I would suggest that all new construction is primarily electric heat in our areas, but there's not as many conversions over the years and so on, as Newfoundland Power customers. So we have not taken--we have not assumed that role to bypass our customer to go to their customer. It is an education thing and there were various programs by the Federal Government and maybe and the Provincial Government, but we have not taken charge, if you will, of that.

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MR. KENNEDY:

Q. The curiosity that I have is you've got referenced in a document, Exhibit DWR-1, I know it's not yours, Mr. Haynes, it would be Mr. Reid's, but it's a report of joint coordination between Newfoundland and Labrador Hydro and Newfoundland Power, and there's a section there on generation and transmission operations. And there's a few references, for instance, page 4 under "system planning" the second sentence says "since the 1970s, Hydro and Newfoundland Power system planning staff have met regularly to discuss the implications of load forecast and customer growth on the need for system additions to determine cost effective solutions and to ensure associated technical issues, such as system protection and under frequency load shedding are appropriately addressed." And then over at page 13, under "observations and"--no, page 13. There we go. Under "observations and conclusions" the second paragraph, "in terms of impact on operational effectiveness, the most significant opportunities for cooperation between Hydro and Newfoundland Power are at

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the generation and transmission level." So I guess, sort of begs the question, isn't it, that if these growth rates that we've been experiencing on a per capita basis in the province are causing these capacity and energy constraints, and we know that effective demand side management programs or conservation programs will at least defer when that new plant is required, and that there's an expression at least in this document that there's this coordination taking place between Hydro and Newfoundland Power in system planning, I don't understand your earlier reply then that well, Hydro kind of throws up its hands because well, that's Newfoundland Power's customers. Would not this coordination go that next step to both yourself and Newfoundland Power trying to figure out how to defer plant construction or at least decrease the amount of energy consumption or demand that customers are placing on the system?

A. Most of the context of that particular response, the document with respect to generation and transmission planning, is that

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when we do go into an area where additional transmission is required or where there are opportunities for Newfoundland Power to do certain things than us, we do look at that in the planning context and try to do what makes the most sense for the consumer. On generation, I mean, there has been discussions, I guess, with respect to how they tie in and so on. But there's been no discussion on, of late, on any major demand side management initiatives. I think there were in the early 90s but they have since ceased, and I think the Provincial Government as well had some kind of a committee on the go for demand side management, which it abandoned as well in the early 1990s.

Q. Mr. Haynes, you've described, both in your testimony throughout the last few days and in your pre-filed, that the new plant that at this point in time is forecast to be required by 2009-2010 will require planning in 2005, correct?

A. That's the time frame that we would have, particularly for a hydro plant, because it takes, you know, four to five years to do the

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environmental parameters to the design, and we don't want to preclude any particular source. We would like to get the most cost effective source for the customers and if you leave it, you could do a gas turbine plant very quickly, but it's not necessarily the cost effective way to approach it.

Q. Now you're aware that, at least on its face, The Electrical Power Control Act places the responsibility of ensuring that adequate system planning is taking place is with the Public Utilities Board?

A. That's correct.

Q. Okay. And we're aware that at least the last number of generation projects, the Granite Canal, your NUGS and I understand the wind generation project that's being proposed as well, have been exempted from the Board's jurisdiction by virtue of Orders in Council. You're aware of that, as well?

A. Yes, I am.

Q. Okay. So barring another Order in Council that would exempt again from this Board's jurisdiction, the construction of new capacity that's going to be required in 2009-2010, can

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MR. KENNEDY:
you tell me what Hydro's intentions are, if any, in coming forward to the Board with an adequate amount of time prior to this 2005 horizon for when you're planning needs to take place to begin that process of allowing the Board to be involved in the process as required under The Electrical Power Control Act?
A. Our intentions would be to proceed as we normally would, and that is that we, as that 2005-2006 time frame approaches, we would re -
Q. Well, just if I could correct you, it's 2005, right?
A. That general time frame. Our -
Q. But you were fairly specific in your evidence, Mr. Haynes.
A. I say 2005. Yes, 2005, okay.
Q. Okay.
A. All right. We may need to go and do a final cost estimate for the Island Pond project. We may go to do an RF--you know, we may--I would suggest that we would, in fact, go to the market, if you will, and to issue an RFP for generation sources that may be available to

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meet that. We would review those particular options. Our options that we would have immediately available to us would be Island Pond. It could be a gas turbine or combined cycle, but based on the load forecast that you see, I doubt very much it will be--Holyrood 4 would be a major player, because it's 150 megawatts, and you know, one terawatt hour, which we really don't need at this point in time. It would be too big a step increase. So we would evaluate our resources against the RFP resources and do a net present value analysis and look at all those options, and it may be a single project that we would propose to the Board or it may be two or three smaller projects, whatever the most economic outcome that meets the reliability criteria that has been adopted.
Q. So that -
A. And that would--our intention would be to propose that to the Board for their review and approval of a course of action.
Q. Okay. And that's after your 2005 planning or is that prior to your 2005 planning?
A. I would suggest in 2005, but we would actually

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start to do that exercise to evaluate those options and we would plan to bring something to the Board in ample time to approve and review and discuss and approve a project or two or whatever to meet that load.
Q. Is there any other new plant contemplated by Hydro other than the wind farm in Burin, at this present time?
(1:30 p.m.)
A. Not on the Interconnected System. We do not have anything that we are discussing or we have any knowledge of that anybody is--we have various solicitations from wind turbine proponents for this and that and something else, but there's nothing that's on the books as far as we -
Q. Okay. What about other than your Interconnected System?
A. There's a wind turbine going into Ramea, which Mr. Martin can speak a bit more about, and there are--obviously there are generation growths in the diesel areas where we may be changing diesels or increasing the size of diesels and so on, and that's a fairly, I won't say routine thing, but it's a more

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common practice because you're operating 24 independent systems than we do on the Interconnected System, and they're much smaller.
Q. Chair, that sort of concludes that area. So I've got just a couple of more. I shouldn't be any more than 20 minutes or half an hour at the most tomorrow morning.
CHAIRMAN:
Q. Okay. Thank you. It would appear, I think, subject to confirmation, but it would appear that the Board's questions will be very, very limited too, Ms. Greene, so I don't know what your redirect would take, but probably not too long?
GREENE, Q.C.:
Q. No. I do have a number of questions in redirect, but they're all fairly short. So our intention would be to start Mr. Martin. From this discussion, it would appear that Mr. Haynes will be finished well before the break.
CHAIRMAN:
Q. Yes.
GREENE, Q.C.:
Q. And our intention then would be to carry on

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GREENE, Q.C.:

and start with Mr. Martin.

CHAIRMAN:

Q. Sounds good. Thank you very much, Mr. Kennedy and Mr. Haynes, and we'll see you at 9 tomorrow morning.

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CERTIFICATE

I, Judy Moss Lauzon, do hereby certify that the foregoing is a true and correct transcript in the matter of Newfoundland and Labrador Hydro's 2003 General Rate Application for Approval of, among other things, its rates commencing January 2004, heard on the 23rd day of October, 2003 before the Board of Commissioners of Public Utilities, Prince Charles Building, 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 23rd day of October, A.C., 2003

Judy Moss Lauzon