New Brunswick Board of Commissioners of Public Utilities

Hearing

In the Matter of an application by New Brunswick Power Corporation dated June 21, 2002 in connection with an Open Access Transmission Tariff

Delta Hotel, Saint John, N.B.
December 18th 2002, 9:30 a.m.

CHAIRMAN: David C. Nicholson, Q.C.

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BOARD SECRETARY: Lorraine Légère

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CHAIRMAN: Is he coming?

MR. HASHEY: Oh yes, he is here.

CHAIRMAN: He is just off running the company.

MR. HASHEY: No. Yes. We can deal with some preliminaries though.

CHAIRMAN: All right. The Board has a preliminary matter. My Commissioners have asked witnesses and parties to restrict the use of acronyms. I think we all know about Debtco and the butterflies and Transco and Holdco and that's all quite acceptable. But when we start getting into CBAS and things it becomes very confusing. So we would appreciate that if you would call it what it is I guess.

Yes, Mr. Hashey. You have some preliminary matters?

MR. HASHEY: We much prefer eagles to butterflies. They tend to soar a little better.

CHAIRMAN: That's probably -- that eagle broke the camel's back as it were yesterday. It was a hawk. I see they remembered it.

Anyway, you had some preliminary matters?

MR. HASHEY: Yes, we do. Thank you, Mr. Chairman. We -- first of all there are a couple of clarifications. I think the first one will -- or comments on the evidence. First of all, Ms. MacFarlane.

MS. MACFARLANE: I have a correction in the responses to the interrogatories in binder A-4. And it is PNB IR-28, page 314. And it is a correction to this table that we wanted to resubmit. And we will deliver copies to the Secretary.

This table in PNB IR-28 is intended to be a continuity table and it was referred to a couple of times yesterday and I noted that it was not continuous. If you look at the table in the IR-28 and you see the bottom half which on -- the first half of the bottom half is the beginning balance and it goes down to an ending balance. And the intent is that that ending balance would come up and form the opening beginning balance. That part works but it's supposed to be balancing to the line called "transmission's share of pension asset", and it does not.

So we have resubmitted that table. And attached to that we have taken the column under 2004, the ending balance of 9.036 and we have reinserted that in table 4, which is the calculation of rate base and the allowable return. We have adjusted line number 5, deferred charges in 2003, 2004 for the correction. It's adjusted by .1 in one year and by .2 in another year. It does not end up affecting the return on -- allowable return on equity. It affects it by $7,700 but because of rounding it doesn't affect it.

So we wanted to put that correction in. Thank you.

MR. HASHEY: Thank you, Ms. MacFarlane.

CHAIRMAN: Exhibit <u>A-30</u>.

MR. HASHEY: Mr. Marshall, I believe you had an indication yesterday that there was some evidence that you would wish to check to complete an answer. Could you do that now?

MR. MARSHALL: Yes. Related to the discounting of ancillary services. I had said it was really a Panel D issue and subject to check with Mr. Scott and Mr. Snowdon. I have done that. I would just like to reiterate and summarize again. We had said that network service was a 12 month contract. And that in that contract the customer would designate whether ancillary services would be self supplied, purchased from a competitive supplier or taken under the tariff. That's correct in what we had stated.

The rates under the tariff are the maximum rates and the rates that would be provided for the services from the transmission provider. But if services can be procured at a lower cost by the transmission provider or the system operator, then that cost savings would be passed on to customers through a discount in the tariff. That's the means for the discounting of the tariff.

Now I think in response to Mr. Nettleton I inadvertently said there would be some competition or reducing it in competition to others and that was misleading. In checking with Mr. Scott and Mr. Snowdon, the transmission provider system operator will not be discounting the tariff in competition to somebody else supplying it. That would be an issue outside the tariff in the bilateral market that customers -- competitive suppliers would be competing at different prices to provide the services and the discounting would not be done by the system operator on behalf of NB Power Generation in that marketplace.

I just want to make that clarification because I think I misled you yesterday with that.

MR. HASHEY: Thank you, Mr. Marshall. I would like now to move on to a few undertakings. We are doing the very best we can, Mr. Chairman, to complete the undertakings, as many as we can obviously this week, and we are I think moving along fairly well with that. They just keep coming up. We can't seem to get them all behind us.

There was one that is outstanding for a period of time that arose during the earlier panels, a question asked to Mr. Snowdon. And the question was when does the contract between New Brunswick Power and Nova Scotia Power, dealing with the use of New Brunswick Power's transmission facilities to service the contract with Prince Edward Island expire?

And the answer on that one is short-term monthly transmission service is being used to deliver energy from Nova Scotia to PEI over the NB Power transmission facilities.

Now I would have no exception at some point if Mr. Zed wanted to add something from the Nova Scotia end. I know that we have been trying to get a little more complete answer. But that is the best one we could supply from NB Power.

So then I would move on to the other undertakings. Ms. MacFarlane, you have I believe five or six answers to undertakings. Would you move in to those please?

MS. MACFARLANE: Yes, I do, thank you. There was an undertaking on December 11th, which is day 8, by Mr. Smellie. It is on page 1085 of the transcript. And it was in respect of how long NB Power has been a member of the Electric Utility Benchmarking Association or EUBA.

The -- NB Power is not a member of EUBA. It is listed as being a participant on their website by virtue of members of our staff having made inquiries of it. It is an organization where membership is free. You make inquiries on the website and you become listed as a member.

And individuals from our fleet department looked into whether or not they would be able to use this -- make use of the services of this association to do benchmarking in their area. After inquiry they determined that they would not be able to.

I also have an inquiry on December 16th in the transcript on page 1402 from Mr. Nettleton. And he asked in reference to table 5 in my evidence, which is the calculation of interest on long-term debt whether interest on early retirement liabilities was included in the interest expense on that table. It is not. It and the cost of the retirement allowance program are both included in OM&A in Mr. Lavigne's evidence.

Further there was an undertaking on December 16th on page 1430 of the transcript, from Mr. Nettleton. And we were asked to determine where in the evidence of Dr. -- or pardon me in the transcript, Dr. Morin had discussed the adequacy of a triple B bond rating as being investment grade.

It is in the transcript December 10th, day 7, page 878. And I will read what he has said. "The technical legal definition of investment grade is triple B or less than triple B. So at triple B you are considered legally investment grade. The next level down would be double B, single B, triple C, et cetera. From a practical perspective the effective investment grade really is single A because a lot of Canadian financial institutions are precluded from investing in bonds rated less than A, either by their own policy or by law."

On December 16th in the transcript on page 1441, Mr. Nettleton was speaking to table 5 in my evidence page 12. And it might be worthwhile to look at that. It is page 12 in appendix A-2 in the direct evidence of Sharon MacFarlane.

We are on line 5. Mr. Nettleton asked if we were to remove the credit spread and instead add the provincial guarantee fee what would the difference be. The credit spread on line 5 is 20.1. The guarantee fee would be 12.8 million. If that were to be used, the long term debt interest of NB Power would be instead of 214.7 on line 6, it would be 207.4. And the cost of debt instead of being 10.7 would be 10.34. Now, again, we believe we have a strong argument for using the credit spread. But that is the answer to that interrogatory, or, pardon me, undertaking.

And, finally, on December 16th, page 1446 of the transcript, Mr. Nettleton asked us to -- he was looking if you remember at the 1991 decision of the Board looking at the appendix 2 which was a balance sheet. And the term long term debt was on the balance sheet but there was no reference to sinking funds, and he asked us to look into that. And we have a submission to make on that.

CHAIRMAN: A-31.

MS. MACFARLANE: You can see on the first page of the undertaking that the request was to confirm that in the 1991 decision long term debt was not reduced by sinking funds. In fact it was reduced by sinking funds. If you turn the page, you will see an excerpt from NB Power's annual report. It is the liability and half of the consolidated balance sheet as at March 31st 1990.

You can see on the top line it says, Long term debt note 4. And the first item, debentures and notes issued by the commission of 1.170 billion. That amount matches what was in appendix 2 in the document that Mr. Nettleton referred us to. But if you turn the page to note 4, on the second page -- pardon me, third page in is note 4, long term debt. And you can see the various maturities listed there coming down to a 1990 total, this would be several lines down. It says debentures and notes. There is a Canadian dollar amount, a Swiss amount, a U.S. amount, and the total is 1718. And you can see just below that that it is reduced by sinking funds. And the total of 1170 ties back to the balance sheet, which is also the amount in the appendix to the decision.

As I said, at the time the CICA requirements for disclosure of sinking funds have changed since this time. You were able to net them out on the balance sheet at this time. And you have to disclose them separately under the current standards.

And those are all my undertakings.

MR. HASHEY: Thank you, Ms. MacFarlane. I have no other preliminary matters, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Hashey.

MR. MACNUTT: Are we going to have that document marked?

CHAIRMAN: It's already marked A-31, Mr. MacNutt.

MR. MACNUTT: Sorry, I missed that.

CHAIRMAN: Mr. Zed?

MR. ZED: Yes, Mr. Chairman, I have two matters. One is a response to an undertaking at page 729 of the transcript relating to Mr. Morrison was inquiring as to the date of incorporation of Emera Energy Inc. And that date of incorporation was March 12th 2001.

And the second matter was alluded to by Mr. Hashey moments ago. Sir, when you asked a question at page 822 of the contract, you asked the question in the context of NB Power and Nova Scotia Power dealing with the use of NB Power's transmission facilities to service the contract on PEI. And Mr. Hashey has given a response which indicates the nature of the contract between Nova Scotia Power and New Brunswick Power. And Mr. Morrison and I discussed your question and I guess what we thought you were really getting at, you can correct me if I'm wrong, is what is the term of the underlying commercial contract. In other words, what is our obligation, contractual obligation with Maritime Electric?

CHAIRMAN: I think it flows from that.

MR. ZED: Yes. And I have ascertained the term of that contract. And we have requested of Maritime Electric permission to publicly reveal that information, rather than go through a confidential process. And I don't have a response as of this morning. I was hoping to get one sometime today. I indicated that I wanted to respond to the Board before the Christmas break. So if we could just leave that until this afternoon, I may have a more complete answer.

CHAIRMAN: Yes. Fine, Mr. Zed. Any other matters? Mr. Nettleton?

MR. NETTLETON: Good morning, Mr. Chairman --

CHAIRMAN: Good morning.

MR. NETTLETON: -- Panel Members. I have one preliminary matter relating to the documentation that we received last night concerning exhibit A-23. As part of my cross examination I will be referring to two of those documents. I have them here now. I could provide them to Ms. Legere, and I have provided a copy to the witness as well, and to my friend Mr. Hashey. I would suggest that we do that now.

CHAIRMAN: And do you want to mark them now, Mr. Nettleton?

MR. NETTLETON: Yes, sir.

CHAIRMAN: Yes, sure. The multi-page exhibit which on the front cover has Central Maine Power Company Annual Production Cost of Service Rates for the year ended 12/31/95 will be exhibit JDI-26.

Okay. Go ahead, Mr. Nettleton.

Q. - Thank you, Mr. Chairman. Ms. MacFarlane, just so that we are clear, this morning in your response to an undertaking concerning bond ratings, I believe it was the third undertaking, and in respect of transcript 1430, you indicated and read into the transcript this morning a passage from Dr. Morin's testimony concerning the investment grade status of bonds.

Would you confirm with me, Ms. MacFarlane, that the triple B bond rating is in respect of a DBRS rating or is it in respect of an S&P rating?

MS. MACFARLANE: I think Dr. Morin was referring to DBRS at the time.

Q. - DBRS?

A. Yes. Yes.

Q. - So it's your evidence is it, Ms. MacFarlane, that a utility with a bond rating of a triple B under the DBRS rating scheme would not be investment grade?

A. It would technically be investment grade. It is not the most efficient point on the cost curve as demonstrated in -- or as exhibited in the presentation that Dr. Morin made. And as he said, a number of institutional investors, pension funds, et cetera, are not able to purchase equities -- or, pardon me, bonds with that rating. And that is part of why, although it is technically investment grade, it is not the most cost-effective place to be.

Q. - Ms. MacFarlane, could you please turn to information response to the Province of New Brunswick information request number 6. And it's at page 20 -- sorry, 273.

MS. MACFARLANE: Yes.

Q. - And I would just like, just so that the record is clear, from that response, and in particular it's response to the first question which is the CIBC World Markets study under the heading "Utilities".

You will confirm with me, will you, that under the Standard & Poor's bond rating there are several utilities having a triple B rating under -- again under a Standard & Poor's rating, correct?

MS. MACFARLANE: Yes.

Q. - All right. And so just again that the record is straight, it is only when that triple B status relates to a DBRS rating that you believe the bond to not meet investment grade?

MS. MACFARLANE: Mr. Nettleton, I didn't say they didn't meet investment grade. The technical legal definition of investment grade is triple B or less than triple B. That is what Dr. Morin said in the transcript.

It is in his view, and I concur with him, not the most desirable credit rating, the most cost-efficient point on the curve for the cost of debt and equity. A is a more cost-efficient point on the curve.

And as he indicated, it also leads to a wider distribution or a wider possibility of holders of the bonds, purchasers of the bonds, because institutional investors are often not able to purchase bonds with a triple B credit rating.

Q. - I understand that answer, Ms. MacFarlane. But what I would like you to confirm with me is that there are several utilities having a triple B bond rating under the Standard & Poor's classification?

MS. MACFARLANE: That's correct.

Q. - Thank you. Now Ms. MacFarlane, I would like to also take you to your undertaking number 34 which is exhibit A-31 in this proceeding?

MS. MACFARLANE: Yes.

Q. - Now I believe you indicated that in your view the balance sheet, the consolidated balance sheet for March 31st 1990 which is attached to that undertaking demonstrates that sinking funds have been netted off the long-term debt amount.

And it is that net amount that has been included in the December -- sorry, in the PUB decision, I believe it is dated May 1991, is that right?

MS. MACFARLANE: Yes.

Q. - All right. Ms. MacFarlane, could you please undertake to provide the consolidated income statement as at March 31st 1990? I don't see it as part of this undertaking. But if you could do that, that would help matters.

MS. MACFARLANE: Thank you. We will do that.

Q. - Ms. MacFarlane, if I could just also on this undertaking -- I think I understand your position with respect to sinking funds.

Do you have the December -- sorry, just one minute. Yes. Do you have the December 6th 1991 decision of the PUB concerning a rate change application?

MS. MACFARLANE: Yes.

Q. - All right. And we talked a bit about appendix 5 to that decision?

MS. MACFARLANE: Yes.

Q. - And it shows there that the embedded cost of debt is 9.5 percent?

MS. MACFARLANE: Yes.

Q. - Could you please undertake to provide the calculation that was used to calculate that number?

MS. MACFARLANE: I will make that undertaking.

Q. - Thank you. Mr. Marshall, yesterday we ended with a discussion on -- I believe it was slide 27 of your presentation materials.

I would like to return to that presentation if you could please?

MR. MARSHALL: Yes. I have it.

MR. NETTLETON: That is exhibit A-26, Mr. Chairman.

Q. - Mr. Marshall, what I'm interested in is with the selection of proxy units and the physical plant comprising those proxy units, the cycle gas turbine and the combined cycle gas turbine and the synchronous condenser.

What I'm wondering, sir, is if you have conducted any optimization studies to determine what types of new generating units would be best choices for the types of services provided in and specific to New Brunswick?

MR. PORTER: We did not undertake such a specific study. But what we did do is take into consideration these types of units are the types of units that we would most likely be involved in new investment in this area and with the capability to provide these services. And that was the rationale upon which we made that decision.

Q. - And Mr. Porter, when you undertook that analysis, why didn't you include that analysis in this application?

MR. PORTER: We responded to an Interrogatory giving that indication, that we made the decision on that basis, that those are the types of units that, if we go out and estimate the costs on such a unit, someone else could go out and come up with very close to the same price, because they are not site-specific. And that has been responded to in a response to an Interrogatory.

MR. MARSHALL: And I might add that those are the same units that we had used as alternatives for long-run marginal cost expansion for the generation system in New Brunswick in comparison to the Coleson Cove project and Point Lepreau projects as hearings before this Board.

So they were real options that we were looking at as generation options and we believed would be the incremental new entrants into this market area.

Q. - Were those generic? Was that a generic analysis in terms of the units? Or were they specific to siting in New Brunswick?

MR. MARSHALL: I believe the actual costing data on those units, the combined cycle was generic. We provided combined cycle data specifically for -- in the evidence. And I believe it is in response to a table we referred to yesterday in one of the Interrogatories.

But the evidence from Coleson Cove had in it the costing for I believe a Courtenay Bay -- an additional expansion of Courtenay Bay similar to Bayside. And it had in it also the larger 400 megawatt generic unit. So it was based on those costs.

And in addition the CT costs of 100 megawatts essentially were based on our knowledge of those costs, detailed costs related to a Millbank type plant.

Q. - All right.

MR. PORTER: That information is in response to the Interrogatory from Nova Scotia Power. It is IR number 29.

Q. - But Mr. Porter, just to be clear, the costing information you have analyzed, the optimization of the units for the specific type of service that you have listed in and on slide 28, that optimization study was not undertaken, is that fair?

MR. PORTER: What optimization study are you referring to?

Q. - Well, I'm wondering if you undertook an optimization study of the types of units, of proxy units that you have listed here for the type of service in and specific to New Brunswick?

MR. PORTER: Mr. Marshall has responded that we looked at what type of units are most likely to be a new entrant into the market.

As Mr. Marshall indicated yesterday, the decision on a new investment is not likely to be driven solely by the need for ancillary services in the market. It would be driven by a need for energy, capacity and ancillary services.

And it is on that basis that we made the selection of the proxy units.

Q. - All right. Let's move on to --

MR. MARSHALL: I will just add that in order to provide regulation, load following and spinning reserve, it is essential that the unit that provides that is actually operating and on line and synchronized with the system.

So the choice of a combined cycle gas turbine plant is a logical choice for the types of units that are available. Those units are built to provide energy and provide the ancillary services required.

They do so in New England, in PJM. In many other markets those are the marginal units in the system. And they are the units that provide those types of on line services.

Q. - Are those actual units, Mr. Marshall?

MR. MARSHALL: In those marketplaces they would be actual units that are operating doing that, yes.

Q. - And in those markets which pricing methodology is used for ancillary services?

MR. MARSHALL: I believe in those markets there are bid-based pricing. There are functioning markets for ancillary services.

Q. - Thank you. Let's move on to talk about energy imbalance. And what I would like to do is take you to the appendix to your evidence, Mr. Porter, which is known as the NB Power Transmission Design document. And it's at page 52 that I would like to start with.

CHAIRMAN: What exhibit?

MR. NETTLETON: I believe it is A-3, sir. Sorry, A-2.

CHAIRMAN: It would be helpful if you could refer to the exhibit to begin with.

MR. NETTLETON: I will try my best, sir.

MR. PORTER: Just for clarification, that is not specifically my document. That is a joint document of Mr. Marshall and myself.

Q. - All right. That was going to be my first question, is who authored this document. It was both of you?

MR. PORTER: Yes.

MR. MARSHALL: We had some assistance from others as well, but we will take responsibility for it.

Q. - All right. Now as I understand it, there is a deadband within which a customer can pay back a negative imbalance or receive back a positive imbalance within a certain period of time. Is that right?

MR. PORTER: That's correct.

Q. - And there is no payment associated with this, is there?

MR. PORTER: No.

Q. - Then outside that deadband the customer pays 110 percent of the marginal cost of New Brunswick Power's most expensive unit or the cost of emergency energy, whichever is greater. Correct?

MR. MARSHALL: For point-to-point service. Refer you to page 54.

Q. - Okay. So network service is not obligated to make any payment then?

MR. MARSHALL: Network service inside the 2 megawatt band or the 1 and a half percent band, the energy is returned in kind. There is no payment.

Outside that, from that bandwidth out to a 10 percent -- plus or minus 10 percent band, the energy imbalance would be settled at a market price.

Outside the plus or minus 10 percent band, network service imbalance is subject to the same charges as point-to-point.

Q. - Okay. So let's talk about just the outer portion then of that -- of those bandwidths, okay. Now when the transmission customer pays New Brunswick Power 110 percent of the marginal cost, that is calculated on New Brunswick Power's most expensive unit. Is that right?

MR. PORTER: As indicated on page 54, at the lower part of the diagram, outside of the bands the customer pays the greater of 110 percent of a combustion turbine costs or the cost of emergency energy if there is emergency energy purchased at that time.

Q. - All right. But in terms of the combustion -- or the pricing based on the combustion turbine, that would in effect be New Brunswick Power's most expensive generation unit, would it not?

MR. PORTER: That's correct.

Q. - So for instance, if a customer has an energy imbalance off peak, he still pays 110 percent times what I will call the most expensive unit. Correct?

MR. PORTER: Correct.

Q. - And if a customer has an energy imbalance on peak, he still pays 110 times -- 110 percent times the most expensive unit. Right?

MR. PORTER: That's correct.

Q. - Don't customers have equal incentives to have imbalances on peak when the cost to New Brunswick Power Transmission is high as well as having imbalances off peak when the cost to New Brunswick Power Transmission would be lower?

MR. PORTER: There is equal incentive in both cases and the reason being that we want to discourage energy imbalance at all times. And that is for two reasons. There are operational reasons and commercial reasons. And there is no need to differentiate between on and off peak incentives. The intention is to establish this pricing to discourage energy imbalance.

Q. - But you have the physical capability to handle the imbalance when it happens off peak, don't you?

MR. PORTER: That may or may not be the case. It depends on the volume of the imbalance, the number of units that are online at the point in time.

Q. - But Mr. Porter, won't it be less expensive to handle to you when it happens off peak?

MR. PORTER: As I said, the intention of putting in this incentive for customers to stay on schedule is an operational issue, it is not so much a cost issue of the -- of the energy that is provided. It is to ensure that the system operator, who in the new world doesn't have the full control over all of the generators, is not subjected to the -- or is less likely to be subjected to generators under-supplying, that is scheduling to supply a certain amount of energy, but not doing so.

In the past on a vertically integrated utility, the system operators -- imagine the individual sitting there controlling the entire system. In the past they had under their control and under the ownership of the vertically integrated utility, the entire fleet of generation.

In the new world, there will be generators on the system and generators wheeling into and out of the system that are not owned by the same entity and there needs to be some additional, some new motivation to ensure that those generators operate as scheduled.

Q. - Mr. Porter, the fact that the energy imbalance charge is not based on, as you say, cost to the transmission provider -- service provider, is that consistent with how other Canadian electric utilities manage the service or price the service?

MR. PORTER: The ones that I have reviewed, the charges tend to be at more than the cost.

Q. - But based on cost?

MR. PORTER: May of them are calculated based on cost. Some are at 110 percent. Some are at 150 percent of cost.

Q. - Let's turn to JDI -- your response to JDI information request 25. And Mr. Chairman, that should be, I am hoping, exhibit A-4.

MR. PORTER: That's correct.

Q. - I got one right. It is page 201, sir. Do you have that page, sir?

MR. PORTER: Yes, I do.

Q. - And can you confirm with me that for Saskatchewan Power negative imbalances charged are at the greater of 110 percent of the transmission provider's incremental cost?

MR. PORTER: Or the charge for emergency energy.

Q. - Fair enough. And that, as your note says, is the same case with Manitoba Hydro, right?

MR. PORTER: That's correct.

Q. - Thank you. Is there any particular reason why New Brunswick Power couldn't charge its energy imbalance on the same basis as Saskatchewan Power or Manitoba Hydro?

MR. PORTER: We believe that with our cost structure versus those of some of the potential market participants there would be indeed commercial motivation for these entities to undersupply, thereby causing the operational difficulties that I spoke of.

Q. - Sorry. You said commercial parties?

MR. PORTER: Yes, I did.

Q. - Could you just elaborate on who you mean?

MR. PORTER: Any of the market participants.

Q. - Do you have any evidence of that, Mr. Porter?

MR. PORTER: I --

Q. - None in this proceeding, correct?

MR. MARSHALL: Under the current tariff the energy imbalance rates are similar to what we have proposed here, $18 on the low side and $100 on the high side. The change on the $100 to a CT based on a fuel cost index takes into account the fact that fuel prices are volatile and change. So it just reflects what that actual cost is.

So the current tariff under which customers take service today has this incentive or disincentive in it to make sure that they stay on balance.

The concern is, as Mr. Porter said, that considering the cost profiles of potential players in this market, the -- to lower that imbalance will provide an opportunity for parties to game the system and lean on the system and to the disadvantage of the default supplier of regulation and load following.

That will be the generator that will have to make up the difference. And that that's a concern.

Q. - That is a concern to the generator though, right, Mr. Marshall?

MR. MARSHALL: Yes, it is. It is also a concern, Mr. Porter said, operationally to the system, to know what loads are on the system, what generators are, so that the quantity of load following and the quantity of AGC that has to be procured in order to follow this will fit within the schedules that we have.

If there is imbalance, greater imbalance in the system, there would be a need to have a greater quantity of generation on AGC, which would mean we would have to increase the costs and charges for ancillary services.

MR. PORTER: I might add that this is a concern that is the case even in areas that have an independent system operator.

If you look at Pennsylvania Jersey Maryland, one of the largest system operators and we believe most successful in establishing independent rules, they too in the case of a energy imbalance, have I think it is $100 a megawatt hour U.S. charge.

And so it is apparent to me that even in the case of an independent, truly independent system operator such as PJM, this is a concern, that the generators supply to the system the amount of energy that they schedule to supply.

MR. MARSHALL: And just could I clarify. I apologize, Mr. Chairman. AGC means automatic generation control. Try to stay away from the acronym.

CHAIRMAN: Thank you.

Q. - All right. If I could have you turn, Mr. Porter and

Marshall, to your open access transmission tariff document which is schedule 4 to I believe A-2.

Sorry, I missed it again, A-3. And it is at page 90, sir, that I would like to turn you to. At lines 28 and 29 on page 90 it states that "In addition the transmission provider reserves the right to recover opportunities foregone because of energy imbalances."

Do you see that?

MR. PORTER: Yes, I do.

Q. - The transmission provider in this case is New Brunswick Power Transmission, right?

MR. PORTER: That's correct.

Q. - Do you know if there are other Canadian electric utilities that have a charge for opportunities foregone in their tariffs for energy imbalance?

MR. PORTER: I don't know the answer to that question.

Q. - All right. I'm sorry to juggle the paper here. But I would like to take you to the response you provided to Information Request 30 of Emera Energy Inc. which is A-4 at page 101.

Do you have that, sir?

MR. PORTER: Yes, I do.

Q. - Now the question asked about opportunities foregone and whether this was a FERC 888 requirement. Do you see that?

MR. PORTER: Yes.

Q. - And so it is not a requirement. Why do you have it in your tariff then, sir?

MR. PORTER: FERC does not define in the pro forma tariff how energy imbalances will be charged. The pro forma tariff has the specific requirement for the plus or minus 2 megawatt deviation bandwidth.

Beyond that they deem that the transmission provider is to define their terms of charging for energy imbalance.

Q. - This is a provision that will be if approved unique to New Brunswick then?

MR. PORTER: I don't know the answer to that question.

Q. - All right. Let's turn now to the answer you have provided to (b). And as I understand it -- sorry, just one moment.

Now in the answer to (b) you referred to the transmission tariff design document. Do you see that?

MR. PORTER: Yes, I do.

Q. - And as I read page 47 of that design document, that section only refers to out of order dispatch costs, correct?

MR. PORTER: That's correct.

Q. - So there are no other opportunity costs that you have in mind here other than out of order dispatch costs?

MR. PORTER: That's correct.

Q. - At -- if you could turn up your response to Bayside Power Information Request 11 which is again exhibit 4. And it is page 11.

MR. PORTER: Yes. I have it.

Q. - Under the proposal by New Brunswick Power, the price for imbalance energy would at times be higher than the cost, is that correct?

MR. PORTER: That is correct.

Q. - Now in the response that you have provided to this Information Request, it states that the incremental revenue will be used to offset the cost of procuring the imbalance energy, correct?

MR. PORTER: That's correct. I might point out for clarification that that is not an exclusive clause. The incremental revenue will be used to offset the cost of the imbalance energy. If the incremental revenues exceed the cost, the treatment was defined in the response to a supplemental from Province of New Brunswick. It is supplemental number 1 -- 2.

Q. - And I think also in your response to Bayside supplemental 8 you indicated that there would be use of a deferral account, correct?

MR. PORTER: Could you repeat the reference please?

Q. - Yes. It is Bayside Power Supplementary Information Request number 8. And that should be A-6.

MR. MACNUTT: Could you clarify that reference?

Q. - Sorry, it is PNB 2. I'm sorry, Mr. Porter, it is Province of New Brunswick 2, Information Request 2. And you have referred to a deferral account in that response, is that right?

MR. PORTER: Yes, that's correct.

Q. - So is the deferral account only for revenues and costs within the deviation band, or does it include revenues and costs outside the band?

MR. PORTER: I just want to be careful there. There are two -- there are two bands here. There are no revenues associated with inner deviation band, the plus or minus 2 megawatts.

Q. - Okay.

MR. PORTER: The plus or minus 10 percent, the difference between the plus or minus 2 megawatts and the plus or minus 10 at market prices is the second band. And that outside, which is what we have been talking about all along, outside of the two bands, that's what we are talking about.

Q. - Right. Fair enough. And is my understanding correct that the net revenues will be accumulated against customer bills monthly?

MR. PORTER: That's correct.

Q. - All right. So New Brunswick Power Transmission will pay 80 percent of the marginal costs for positive energy imbalance. Is that right? Or $18, those are the numbers.

MR. PORTER: Could you repeat that, please?

Q. - Yes. What I'm wondering, Mr. Porter, is whether New Brunswick Power Transmission will be paying 80 percent of the marginal costs for positive energy imbalance or $18?

MR. PORTER: They will pay the lesser of the two.

Q. - All right. And so a difference of 20 percent exists between what you pay to the customer and what your costs are, correct?

MR. PORTER: That's correct.

Q. - So a savings of 20 percent arises?

MR. PORTER: Savings to whom?

Q. - Good question, is what happens to that difference. Does it go into the deferral account?

MR. PORTER: Yes, it does.

Q. - All right. Now how will the crediting take place? Will it go all to -- will the amount go to all transmission customers or only those with payments or receipts from energy imbalance?

MR. PORTER: All transmission customers.

Q. - All right, thank you. Okay. On to the power factor penalty provisions, and that's where I would like to first take you, Mr. Porter, is page 39 of the New Brunswick Power Transmission tariff design document. I'm under heading 3.3.4.

MR. PORTER: I have that.

Q. - Mr. Porter, could you just generally describe for me the purpose of this penalty charge?

MR. PORTER: The purpose is to provide incentive for the customer connected to the NB Power transmission system to maintain an appropriate power factor. And by appropriate power factor I mean equal to or greater than 90 percent.

Q. - All right.

MR. PORTER: And the reason that we would want to do that is to help minimize losses on the transmission system.

Q. - And is my understanding correct that the power factor penalty is four times the wire tariff?

MR. PORTER: That's correct. Four times the wire tariff, that's on the incremental. That is on the difference between 90 percent of the KVA demand versus the peak kilowatt demand. And I might add that that's effectively identical to the mechanism that's in our current large industrial rates.

Q. - What justification do you rely on to have the penalty factor, the power factor penalty either proposed or current based on principles of cost causation or proper cost allocation? Is it based on either cost causation or cost allocation principles?

MR. PORTER: I believe it's based on cost causation. But that goes back well before my time in that this is an historical mechanism that has been in the NB Power rates for large industrial customers.

MR. MARSHALL: My understanding is it's pretty standard practice in all bundled rates to customers for power factor penalties, 90 percent.

Q. - Based on four times the wire cost?

MR. MARSHALL: The fact is that the four times is equivalent to the current penalty. But the fact that there are penalties for power factor is a standard rate making mechanism in all rates that I'm aware of.

And the reason for it, as Mr. Porter said, is that it is that losses will increase. And it goes back to my explanation yesterday about what VARS are and the fact of imaginary power.

What happens is, is that if the electricity supply on the system was all lights we would have no need for power factor correction because the voltage and the current would be in phase. But in -- the fact is that we have many motors that are on the system. And when motors operate, motors -- the magnetic circulating field of motors require and pull the current out of phase from the voltage. So the motors pull it out of phase. This increases the current required through the system. This increased current causes increased losses. So in order to keep the voltage at a reasonable level and provide proper voltage for everybody's end use and the system to operate properly and minimize losses in the system, we have to maintain power factors above 90 percent.

Q. - Right.

MR. MARSHALL: That's the rationale for why it's in the tariff.

Q. - I think I now understand. And we don't take issue with the purpose. What I'm trying to understand is the methodology you use to price this penalty factor.

Did you conduct any studies or did you perform any sort of cost of service allocation analysis with this applied for penalty factor?

MR. PORTER: One of the principles that was applied in this case was the --

Q. - Mr. Porter, could you please just answer the question and then I would be happy to hear your explanation.

Did you conduct any studies, cost of service allocation studies or any sort of review of other jurisdictions and how they calculate the penalty factor?

MR. PORTER: No, we did not. And what I was attempting to say was that we follow the White Paper energy policy of making sure that rates are available to customers under similar terms and conditions as what they have today. And we know that we have done that with this implementation of the power factor penalty.

MR. MARSHALL: So the rate is based on the current penalties that are in the current large industrial rates for power factor.

Q. - Do you know whether the power factor penalty was a topic of discussion in the last cost of service allocation study that was examined by this Board?

MR. PORTER: I am not aware.

Q. - And if it wasn't considered there, is to fair to say that it hasn't been a matter that has been the topic of this Board's considerations?

MR. MARSHALL: Again I have to speculate. If it wasn't considered there, as it wasn't seen to be an issue, it has been in the rates all along, so this Board under that basis would have accepted it.

Q. - And if my clients were interested or concerned with the power factor penalty amount applied for, it would only be in this proceeding that they could raise those concerns, correct?

MR. MARSHALL: Well, the power factor penalty is an issue to current supply out of phase losses on the system. The losses in the system are at the risk of the transmission provider. The Transco has set losses at 3.3 percent of system average losses. And if they are higher than that, they take the risk of what it is. So they want to make sure that power factors will be in line so that losses will be as projected.

Q. - Do you remember my question, Mr. Marshall?

MR. MARSHALL: Could you repeat it?

Q. - If my clients were concerned with the power factor penalty amount and how it has been designed, this is the only proceeding by which those concerns could be raised?

MR. MARSHALL: Yes.

Q. - Correct?

MR. MARSHALL: Yes, that's correct.

Q. - Thank you. Let's turn to the issue of the charge for off peak. What I would like to do is take you to page 36 of that tariff design document. And it's in particular lines 21 through 28.

MR. NETTLETON: Mr. Chairman, I see that we are at quarter to 11:00. Do you want to break now or do you want to continue on? I'm about to go in here.

CHAIRMAN: We have consensus. We will take our break now.

MR. NETTLETON: Thank you.

(Recess - 10:45 a.m. - 11:00 a.m.)

CHAIRMAN: Go ahead, Mr. Nettleton.

Q. - Thank you, Mr. Chairman. Two areas left. The first deals with the charge for off peak. And as I indicated before the break, I would like to take you to page 36, lines 21 and 38 of the tariff design document. Do you have that, Mr. Marshall and Mr. Porter?

MR. MARSHALL: Yes.

MR. PORTER: Yes.

Q. - All right. Now for network service is it correct to understand that the billing determinant will be the greater of the net monthly nonconcident peak demand in the on peak hours or 71 percent of the net monthly nonconcident peak demand in the off peak hours?

MR. MARSHALL: That's correct.

Q. - All right. What I'm interested in, sir, is how you have calculated the 71 percent? Can you help me with that?

MR. PORTER: That calculation is based on five on peak days out of a seven day week.

Q. - Okay. And so is that just simply five divided by seven, that simple expression?

MR. PORTER: That's correct.

Q. - It is? That is --

MR. PORTER: Yes.

Q. - And the reason that you have delineated between on and off peak hours is what, sir?

MR. PORTER: It's to encourage the shifting of load from on peak hours to off peak hours.

Q. - So that is a good thing?

MR. PORTER: That's correct.

MR. MARSHALL: It could be. It's to provide an opportunity for the customers so that they are not as -- it's to avoid the punitive nature of a nonconcident peak in the off peak hours. To give them a little bit more flexibility and able to manage their load.

Q. - It provides incentive, correct?

MR. MARSHALL: It does provide some incentive to do that, yes.

Q. - To move load to the off peak hours?

MR. MARSHALL: Yes.

Q. - Thank you. Now back to the five divided by seven calculation, Mr. Porter. Have you done any studies or analysis as to the cost causation of that calculation? Are there any cost causation principles associated with that calculation?

MR. PORTER: No. The 71 percent factor we believe provides adequate incentive to encourage the shifting of load to the extent that that is possible in our customer base.

Q. - See, that was easy. Last item. I would like you to turn to exhibit A-23. And that, Mr. Porter, was the undertaking you provided to Saint John Energy. And it relates to the two documents that were filed this morning, JDI 26 and 27. Could you get those documents before you, please?

Mr. Chairman, I understand that there is a bit of a bet going around in the collective peanut gallery as to the hour in which I will finish. And I am hoping that Mr. Morrison won't win, so there might be some incentive for that.

MR. MORRISON: Have you done a study on that?

MR. NETTLETON: Maybe. I'm not going to tell you though.

Q. - All right. Mr. Porter, the response to the undertaking that you have provided as I understand it is a chart -- or two charts rather, dealing with the dollar per kilowatt hour on a yearly basis for generation capacity associated with ancillary services. Is that right?

MR. PORTER: It's our dollar per kilowatt year basis for generation capacity, yes.

Q. - So the numbers that are shown here do not reflect the price paid by customers for ancillary services, is that fair?

MR. PORTER: That's correct. And that's because the undertaking was in response to a request from Mr. Young to see the pricing -- what was being paid to generators for the provision of this service because their concern was the possibility that generation could be being overpaid or perhaps underpaid to the detriment of those that take service from those generators.

Q. - And so the numbers that you have provided in these charts are simply one input upon which prices for ancillary services are being calculated, is that correct?

MR. PORTER: That's correct.

Q. - Can you explain the weighted average calculation that you have included on the bottom of the line that starts with the words "weighted average". Can you explain those?

MR. PORTER: Yes. For each of the services we have shown here the price that is -- represents the dollars that would flow from the transmission provided to the generator per kilowatt year of generation.

We also have but not showing on this table the quantities of each of the services, so that is the kilowatts of generation capacity required to maintain system reliability for each of the services -- through each of the services. And this is a straight weighted average of the prices versus the quantities of each service.

And we would certainly be happy to provide the quantities if that would be of use.

Q. - I thank you for that. I don't -- let's see how we go. Because I'm not sure if we need it but let's see how we go. And then you are taking that amount for each service and doing a weighted average calculation with it, is that correct?

MR. PORTER: Yes. For each service we look at the respective price and the respective quantity to come up with a weighted average on the total portfolio of services.

MR. MARSHALL: Yes, but -- just the -- there is no weighted average for an individual service. The regulation service, for example, in the table, the generation dollar per kilowatt year charge, 8199 dollars a kilowatt year would be multiplied by the quantity required of regulation, which is 17 megawatts, which would give a revenue requirement then that would be the numerator in the rate calculation to be then divided by the billing determinant denominator. And that's done for each service.

So there is a -- this is a dollar per kilowatt year rate as the proxy cost for procuring the service. Then you multiply it by the megawatts of required capacity to provide the service, to get a revenue requirement for each service, and divide by the billing determinant to get the rate for each service.

Q. - So the megawatt quantity for each service forms the basis to obtain the weighted average?

MR. MARSHALL: The megawatt requirement of each quantity is the basis of the weighting to get the weighted average in the table.

Q. - Okay. And again this isn't in respect of the prices that ratepayers charge, these numbers here. We have to go to Saint John Energy 3, I believe, to understand the prices for the rates, is that -- well let's turn to Saint John Energy IR-3 which is in A-4. That's page 474.

MR. PORTER: Yes. We have that.

Q. - All right. And as it relates to the ancillary services, Mr. Porter, could you confirm that those are the last three rows on that chart found at page 474?

MR. PORTER: Yes.

Q. - And let's just go through the columns then for each of those, just the ancillaries.

Subject to check, the ancillaries for New Brunswick

Power would amount to $11.40, for Hydro Quebec $2.24, for Manitoba Hydro $5.03 and for Saskatchewan Power $10.36 and for BC Hydro $3.21.

MR. PORTER: Yes, subject to check.

Q. - Now back to A-23. Under the next column -- or sorry, under the next chart, which is I believe entitled "Maine Utilities", there is again another comparison of the ancillaries proposed by New Brunswick Power to various Maine utilities, correct?

MR. PORTER: Correct, with the caveat that those with an asterisk are not the current rates. We have the notes on the bottom indicating that those are the rates that were filed with FERC and accepted at the time that those systems went into an open access transmission tariff situation.

Q. - Okay. But you will confirm with me -- well, let's look first at JDI-26, if we could, which is the Bangor Hydroelectric document.

Now Mr. Porter, you will confirm with me that this is the material that you provided to me through your counsel with respect to the data or working papers used to calculate the numbers found in this chart, is that right?

MR. PORTER: Yes, that is correct.

Q. - Okay. And with respect to the prices of ancillaries, I believe we have to flip to exhibit number 4, page 1. Sorry --

MR. MACNUTT: What was that reference to exhibit A-4 again?

Q. - If we flip over five pages, Mr. Porter, to what is entitled "Schedule 1", and the schedule is entitled "Bangor Hydroelectric Company Transmission Wheeling."

Do you have that table there?

MR. PORTER: Which page again? Fifth page of the package or the fifth page of --

Q. - Fifth page of the package.

MR. MARSHALL: I think it is the sixth page.

Q. - It is indeed the sixth page. And what I'm looking at is schedule 1. It is entitled "Schedule 1" in the top right corner. Do you see that?

MR. PORTER: Yes, I do. Can you confirm the title? Because I believe there is more than one schedule 1 in this package.

Q. - Yes. The title is "Bangor Hydroelectric Company Transmission Wheeling Rate Summary." Do you have that?

MR. PORTER: Yes, I have that.

Q. - Okay. And what I'm looking at are lines 7, 8 and 9. Line 7 is entitled "Regulation and Frequency Response Service."

And the year, the dollar kilowatt year amount for that is 52 cents. Do you see that?

MR. PORTER: Yes.

Q. - And the operating -- line 8, the operating reserve, spinning reserve service, the amount there is $3.15?

MR. PORTER: Yes.

Q. - And the operating reserve, supplemental reserve service, line 9 is shown also as $3.15?

MR. PORTER: Agreed.

Q. - And my handwriting calculation as shown there is $6.82 at the bottom of that. Do you see that?

MR. PORTER: Yes, I do.

Q. - And subject to check, those would be the charges for the ancillary services provided by Bangor Hydroelectric Company?

MR. PORTER: Yes, all in US funds.

Q. - Yes.

MR. MARSHALL: That would be about 10.50 Canadian.

Q. - Thank you. And that would be using what type of interest rate or conversion rate?

MR. MARSHALL: 64, 65, just a ballpark estimate.

Q. - Okay. Now Mr. Porter, the only other document that you provided -- that I provided you with here, that I would be interested in your views on, is the exhibit that has been marked JDI-27.

And that document refers to the Central Maine Power Company, correct?

MR. PORTER: Yes, I have that document.

Q. - Okay. And again back to A-23, that is shown also in the Maine Utilities chart, correct?

MR. PORTER: Yes.

Q. - And this is the document that you used to prepare your analysis, and in particular the numbers under the column "Central Maine", correct?

MR. PORTER: Yes.

Q. - Now I would like you to turn to the last three pages of that document. And the first one is entitled "Load Following"?

MR. PORTER: Yes, I have that.

Q. - And would you confirm with me, sir, that the yearly rate for regulation and frequency response service shown is 89.55 cents?

MR. PORTER: Yes.

Q. - Okay. And then over the page, the development rate of rate for operating reserve, spinning reserve service, that amount is stated as $2.6425?

MR. PORTER: Yes.

Q. - That is 2.6425?

MR. PORTER: Yes.

Q. - All right. And then over the page, the development rate or development of rate for operating reserve, supplemental reserve service is expressed underneath the chart and is $4.874 -- sorry, 4.8754 cents, correct?

MR. PORTER: Yes.

MR. MARSHALL: Not cents. That is dollars per kilowatt year.

Q. - Thank you. Now Mr. Porter, you indicated that, back on exhibit A-23, that subsequent to the dates upon which this information -- that JDI-26 and 27 were information dated in 1995, correct?

MR. PORTER: Could you repeat the question, please?

Q. - Yes. I wasn't clear. If you look at both JDI-26 and 27, that information is dated in 1995, correct?

MR. PORTER: Yes.

Q. - And then if we go back to exhibit A-23 you have noted by way of asterisk that charges for Bangor Hydro and Central Maine are applicable prior to the implementation of the ISO New England market, right?

MR. PORTER: Yes.

Q. - Why did you make that notation?

MR. MARSHALL: Just to clarify, the rates -- these would have been the rates that they filed with FERC to meet Order 888 requirement went into effect in September of

1996 and were in effect up until the Northern Maine ISA was formed.

And then at that time there were maybe adjustments to rates for the Norther Maine ISA. So these are the FERC Order 888 rates for those specific utilities as filed and approved in 1996.

Q. - And Mr. Porter, it is your view that these rates are relevant and applicable for comparison purposes to this application and the ancillary services that you are proposing here?

MR. PORTER: Yes, I do. Because we are proposing pricing be used in the absence of a competitive bid-based market. And that is what was done at that time. So there is a parallel there definitely.

MR. MARSHALL: But I might want to point out that the rates that we have gone through on each of these schedules, the issue is not the rate that is charged to customers. The rate charged to customers is a function of the generator cost and the quantity of service required.

So the fundamental rates that may end up being charged to customers under these schedules may be lower than NB Power rates in this application when in actual fact the generation costs to provide them are higher.

It is because the quantity of service obligation at each of those utilities is much smaller than what is required on the NB Power system to maintain reliability.

And that occurs because they exist in a much larger power pool and share reserves across the whole New England pool and so have a much smaller requirement that they have an obligation to provide.

MR. PORTER: I might add to that, as I noted earlier, that this undertaking was in response to the question from Saint John Energy, Mr. Young. And it is on page 514.

And he just says "My perspective is just making sure that NB Genco doesn't -- you know they are not giving value away outside the province."

Q. - Thank you, Mr. Porter. Could I have you turn to the eighth page of the Bangor Hydro document? And the title of that document is "Schedule 4, page 1 of 2, Bangor Hydroelectric Company Transmission Wheeling Rate, Reactive Supply and Voltage Control from Generation Source Services."

Do you see that?

MR. PORTER: Yes, I do.

Q. - Now Mr. Porter, yesterday we spoke of the concern that you expressed with respect to the disclosure of confidential information.

Do you remember that?

MR. PORTER: Yes, I do.

Q. - And sir, would you agree that the information provided on schedule 4, pages 1 and 2, would be the information that would be used to calculate and determine the ancillary services charged by Bangor Hydro?

MR. PORTER: That depends on the methodology that was selected. There is certainly more than one way to come up with the embedded cost pricing on reactive supply and voltage control.

Q. - Right. But it would be an embedded cost pricing methodology?

MR. PORTER: What would be?

Q. - The method used here?

MR. PORTER: Yes.

Q. - All right. And it is this -- from your review of this information, that is schedule 4, this is the information that you would consider to be commercially sensitive in the context of New Brunswick and New Brunswick Generation?

MR. MARSHALL: There is information here that is commercially sensitive on total production plant cost by units and plants, generator original costs, site original costs.

So there is data here that has commercial value in the total cost of the plant.

Q. - Mr. Marshall, do you see in the future the opportunity for a utility such as Bangor Hydro to provide ancillary services into the province of New Brunswick?

MR. MARSHALL: No. Bangor Hydro does not have any generation. In the state of Maine all generation that was in this filing has since been sold off to competitive suppliers.

So Bangor Hydro is strictly a wires company today and do not have the ability to provide ancillary services.

MR. NETTLETON: Thank you, sir. Thank you, panel. My questions are over subject to the remaining undertakings.

CHAIRMAN: Mr. Belcher has gone home I guess.

MR. HASHEY: He indicated to me that he would have no -- Mr. Belcher indicated that the questions he had were covered.

CHAIRMAN: Okay. Thank you, Mr. Hashey. Mr. Zed?

MR. ZED: No questions, Mr. Chair.

CHAIRMAN: And it is Perth-Andover? Saint John Energy going to take Perth-Andover's slot? Or are you going to go into your own slot?

MR. YOUNG: Your choice, Mr. Chairman.

CHAIRMAN: Well, let me just -- does the Province of New Brunswick have any questions?

MR. KNIGHT: Yes. We have a couple of questions.

CHAIRMAN: I'm just looking at -- we have got 25 minutes till noon. So maybe the Province could ask theirs now.

CROSS EXAMINATION BY MR. KNIGHT:

Q. - Good morning.

MR. MARSHALL: Good morning, Mr. Knight.

Q. - A couple of days ago we had a bit of a discussion about the issue of rate shock as it pertained to the bundled rate.

The Province in its consultations leading to the development of the energy policy identified that rate shock was of particular concern to the issue of self-generation.

And that concern is expressed in exhibit JDI number 3, the section 3142 relating to self-generation, where the Province directed that the Market Design Committee would examine the means by which rate shock to existing self-generation should be avoided.

And as a result of that, in the market design report, which is exhibit A-5, appendix 8, attachments to Responses to Interrogatories, number 1, volume 2 of 2, speaking again of self-generator rate shock.

In particular on page 53 of that exhibit, recommendation 669, the market design --

MR. MARSHALL: Could we get that please?

Q. - Sure.

CHAIRMAN: Do you want to give us the reference?

Q. - It is exhibit A-5, appendix 8, pages 52 and 53.

MR. MARSHALL: Yes. I have it now.

Q. - In that recommendation the Market Design Committee recommended that the design of the transmission tariff seek to mitigate rate shock to self-generators.

The first question that we would have then is what consideration has NB Power given to mitigating potential rate shock to existing and to new self-generators?

MR. MARSHALL: We have reviewed the tariff, looked at what flexibility exists in the tariff for customers to take service.

And we have -- based on the flexibility in the tariff, believe that there is no requirement to deal with specific issues related to rate shock. We do not believe that there will be any significant rate shock at all from the implementation of this tariff.

And I might note that in this report, the Market Design Committee report, just even on that same page where you make the recommendation, recommendation 669, I would just note the paragraph just above it, where the committee noted that ancillary services and transmission charges for self-generators is a complex issue.

The actual impact on specific self-generators will depend on the kind of service they now receive on their own operating characteristics and on the decisions, note the decisions that they may make in response to the tariff changes. The committee also noted that these tariff rates would be set in the tariff as constructed and filed by responsible parties.

So the fact that customers have a choice, they can choose network service or point-to-point service, and they can self-provide some of the ancillary services.

Current self-generators in New Brunswick today all are served under rates that are interruptible on 10 minutes notice. They should have the capability to self-provide supplemental 10-minute reserve and 30-minute reserve from their own sources.

And on that basis that mitigates a significant amount of the cost. And by using point-to-point service, if they are a self-generator that operates a lot of the time and have therefore a low load factor in taking energy from the system, they can take point-to-point service and mitigate the transmission charges significantly through use of point-to-point service as opposed to network.

So I think those are things -- and just in response to that, whether you are going to get there or not, I would like to bring up the fact that JDI submitted a supplemental response where they put on the record the actual billing determinants and costs related to the Irving Pulp and Paper mill at Reversing Falls, based on the history of 19' -- of 2001.

It is clear from that information -- they have assumed network service and total supply of all ancillary services. And under those numbers they would say the cost would increase from $234,000 up to 616'. That is a -- and they say that is a 63 -- 163 percent increase, that that's rate shock.

We would agree that that would be rate shock. The fact is we have redone numbers and are prepared to submit them here to show that they have the opportunity to take point-to-point under the same data and self-provide some of those ancillary services, that the actual costs will reduce back down in the same order of what the costs are today.

CHAIRMAN: Mr. Marshall, that was all very interesting. But the question was what you had done, not to argue about an exhibit that somebody else put in. So try and answer the question --

MR. MARSHALL: Okay. What we have done is we reviewed the flexibility in the tariff. We implemented the off-peak demand rate to provide some movement for these types of generators to move their load, so that they would have some flexibility in how they operate their loads.

And we -- the tariff provides them to choose what type of service they want and to self-provide ancillaries. And we think that is enough to mitigate the rate shock issue.

Q. - So the sentence that follows the Market Design Committee recommendation 669 speaks of phasing in of transmission tariffs and ancillary service charges.

So in your opinion it would not be necessary to design the tariff such that there would be a phasing-in?

MR. MARSHALL: As filed the tariff does not include a phasing provision in it. And based on the flexibility in the tariff we don't think it is necessary. But it is up to the Board to decide whether or not they think it is prudent.

MR. KNIGHT: Okay. Thank you, Mr. Marshall. That is all from the Province.

\ CHAIRMAN: Thank you, Mr. Knight. It looks like Saint John Energy. Do you want to break for lunch now and come back at say quarter after 1:00?

MR. YOUNG: Your preference, sir. In fact that probably -- if we started now it would put us halfway through what we want to cover.

CHAIRMAN: Okay. Well, we will break now for lunch and come back at quarter after 1:00.

(Recess - 11:45 a.m. - 1:15 p.m.)

CHAIRMAN: I have indicated to most of the parties that the Board's intention would be after the intervenors conclude their cross of this Panel, we will adjourn over until tomorrow morning, so that Board counsel and staff can try and shorten up their cross.

Saint John Energy?

CROSS EXAMINATION BY MR. YOUNG:

Q. - Thank you, Mr. Chairman. Mr. Porter, Mr. Marshall, Ms. MacFarlane and Mr. Lavigne, good afternoon.

I will be speaking on behalf of three municipal utilities, Saint John Energy, Energy Edmundston, Perth-Andover Electric Light Commission.

The questions to Panel C will be focused on five areas of concern, and deal mainly with the evidence and expertise of Mr. Porter and Mr. Marshall.

To begin I would like to focus on businesses being treated equal under the tariff, in particular distribution utilities being treated equally. The reference on this would be exhibit A-26, Panel C presentation, page 5.

In fact, you probably wouldn't even have to turn that up, just because I'm not going to be specific on that.

It's a generality in that area.

Mr. Marshall, since you are applying for a transmission tariff as NB Power, an integrated generation, transmission and distribution company, but expect to implement the transmission tariff through a stand-alone transmission company that would be a butterfly from the present NB Power, can you appreciate that we have some concern about having your future distribution company on a level playing field with municipal distribution utilities?

MR. MARSHALL: Yes.

Q. - Will all the distribution utilities, including the new butterfly NB Power Disco, be treated equally when the industry is restructured?

MR. MARSHALL: Under this tariff they will be treated equally, yes.

Q. - I take that to mean that all applicable charges will be identical, including network charges, point-to-point charges, SOS charges and any other charges that might apply. Is this correct?

MR. MARSHALL: All charges -- all customers under this tariff will be treated equally.

Q. - Okay. I just had a point brought to my attention. I said the SOS is under this tariff and in fact it is not under this tariff.

MR. MARSHALL: No, it's not under this tariff.

Q. - I just want to make sure it's correct in the transcript. What are your thoughts on SOS? Is that going to be held the same as the other three issues I brought forward, treated the same?

MR. MARSHALL: That would be speculative at this time.

Q. - Fair enough. Mr. Porter, do you agree with Mr. Marshall's response?

MR. PORTER: Which part of the response? Can I clarify the --

Q. - Mr. Marshall's responses are always short and to the point.

MR. MARSHALL: A simple yes will do.

MR. PORTER: Yes.

Q. - Thank you. I like those once in a while. Does this mean that NB Power Disco will be billed the same as Saint John Energy and municipal utilities and have the same determinants as far as you are concerned?

MR. PORTER: Yes, that's correct.

Q. - Okay. This gets us into a fairly confusing area, which is the area of coincident versus noncoincident demand as the basis for billing determinants.

The Market Design Committee recommended that billing be based on noncoincident peak demand. The government has adopted this recommendation in that they have not explicitly said otherwise. Do you agree with this statement so far, Mr. Marshall?

MR. MARSHALL: Speculative, I guess. My understanding is the government accepted the recommendations of market design and said so in a press release. Until the legislation comes down and all the rules are put in place and it's law, we won't know for sure.

Q. - And your policy as far as you know for sure at this time is to base billing on noncoincident peak demand also?

MR. MARSHALL: What we have is what is in front of us in this tariff. We are billing on noncoincident peak for network service, on contracted service for point-to-point.

MR. PORTER: Which is consistent with market design recommendations.

Q. - So you can confirm my understanding on how you will be treating NB Power Distribution after the butterflies have flown. My understanding is as follows. NB Power Distribution will be billed under the transmission tariff and for SOS on a noncoincident peak basis, which basically means that billing will be based on the sum of the peak demands at each of its substations without regard to when that peak occurs. Is that correct?

MR. PORTER: That's correct.

MR. MARSHALL: Yes, that's correct.

Q. - Thank you. The next focus I have, next issue is partial SOS supply. And this is to begin with Mr. Marshall. The purpose of this is just to get clarification that municipal electrical utilities need to arrange for transmission under the OATT only for the portion of its supply that it does not take under SOS. And the references for this are exhibit A-6, and also from the transcript day 3, November 20th, page 506.

We earlier asked Panel D a similar question. And our review of the transcript indicates some lack of clarity. I will try this again.

The question is if a load connected to the transmission system such as Saint John Energy, takes part of its supply under SOS and part through bilateral contract, will it be considered a transmission customer with respect only to the bilateral contract?

MR. MARSHALL: I think really that's a standard offer question of how that transmission be split up. Basically under standard offer, if Saint John Energy remains standard offer customer the customer of Transmission would be NB Power Distribution and Customer Service.

If Saint John Energy take a portion of their supply under standard offer and a portion of their supply in the marketplace, then I think Saint John Energy would need to become the transmission customer for the total transmission and it has two sources of supply meeting its load and two sets of resources that have to balance against that, the contract from a competitive supplier and the portion from standard offer service. The billing determinants would be the same, what is the total noncoincident peak at each delivery point if it was under network service.

Q. - Are you telling me that Saint John Energy would become a transmission customer for both SOS and the bilateral contract separate from it?

MR. MARSHALL: No. I'm saying the one entity has to be the transmission customer at each delivery point. Now because you will have different generation suppliers to that delivery point, one entity has to manage that transmission and schedule what is required.

Just as far as the tariff -- Mr. Porter pointed out to me as far as the tariff is, NB Power Transco and the system operator, it's indifferent to them whether that transmission is going to be scheduled and managed by NB Power Distribution or by Saint John Energy. It's just that it has to be managed by somebody and the bill will be sent out based on the total.

There is a need to split the bill up between the parties, that basically the bill then has to be sorted out in some way. And it's an issue in standard offer how it would split out. So that is an issue for how the standard offer rates would go forward, as to how you split out the transmission components between the standard offer and the competitive supplier.

Q. - It appears that there is a great uncertainty around how this tariff fits in with SOS. And since it is the government's clear intention to continue to provide existing customers with service similar to existing service through SOS, we are having some difficulty understanding how your application impacts us and our customers.

Now can you tell about how the proposed tariff meshes with SOS arrangements? How exactly do these two mesh together just beyond your initial information? Because we are under the understanding if it's SOS and the way you explained it to us earlier, SOS would be through a contract between Saint John Energy and NB Disco.

MR. MARSHALL: That's correct.

Q. - And that's separate. And then if we wanted to go to the market that's a bilateral contract that, yes, we are our transmission customer and we will deal with that at that time in that manner. We didn't think that it was that part of an issue.

MR. MARSHALL: Well I think that's what I just said.

Q. - Oh. Thank you. I got a different version of it, that was all, sir.

CHAIRMAN: Maybe you should restate, Mr. Marshall.

MR. MARSHALL: You asked if you remain as part on standard offer and part as a competitive -- from a competitive supplier, then there is -- from under the tariff the measurement and the billing determinants will be the same.

The issue will be how do you sort out which portion goes to NB Power Distribution because they are the -- they are delivering the SOS service which will include the transmission and which portion goes directly to Saint John Energy because of -- or the competitive supplier if it's bundled service from them, you have got to sort out which piece goes to which supplier. That becomes an issue to be sorted out in the standard offer rates.

Q. - It's just that with Saint John Energy we want to make use that if our customers choose not to choose, which they want to default, that SOS is the default for them. And I don't think that if one of our customers wants to make a decision and choose green power that immediately everybody else has to come off default. We want to have the options available to our customers that if someone wants SOS, so be it, it's their choice.

If someone else wants green power, someone else wants time of use and it goes on and on, if there are separate contracts, we want to deal with the separate contracts. We don't want them all overlapped and confusing to our customers. That was the only reason I was bringing this up. But I'm comfortable with the answer I have gotten so far, so I will go on.

All right. This issue -- this focus is going to be on stranded costs and falls out of the previous question and the question prior to that. Continuing the issues which arise when a customer takes only part of its supply under the proposed tariff. Would there be an exit fee when the customer leaves SOS supply?

MR. MARSHALL: My understanding, that hasn't been determined yet. The White Paper says that customers -- eligible customers in the market can choose to gain competitive suppliers but that there should be no cost shifting to other customers.

The issue of stranded costs was put forward to the Market Design Committee. They reviewed it, made some recommendations but again did not come down with a definitive methodology of calculating or determining -- or how that would occur. And until the legislation comes out whether or not -- what the stranded costs may be or mechanism or who is responsible for them are yet to be determined.

Q. - In your view is there a need for an exit fee?

MR. MARSHALL: The -- that would depend on the level of cost shifting that could occur. There is a need for an assessment of whether there should be an exit fee. But there may not need -- be a need for an exit fee. That would depend on whether or not the costs that potentially would be shifted could be mitigated so that there would not be any cost shifting.

Q. - Is NB Power planning on doing an assessment?

MR. MARSHALL: I believe they will when the legislation comes out. And I think if this Board has authority over it or whatever, there will likely be a hearing or something. But yes, there would be an assessment. But until the vesting contract is written and done and the Minister sets the price in the vesting contract, it is impossible to do calculations to determine whether there will or will not be any stranded costs.

Q. - Just to finish off this topic. Just to be absolutely clear, the exit fee would consider only the part of the customer's supply that is not going to be bought under

SOS?

MR. MARSHALL: That would be my understanding. But again, until the details are out. But that would be my understanding at this time.

Q. - We find we are all waiting for details. Mr. Porter, just exhibit A-23. Could you bring that before you? A-23 was the ancillary services undertaking.

MR. PORTER: Yes, I have that in front of me.

Q. - Okay. I will just give the opportunity for the Board. The majority of these issues that we had before you have all been covered by other Intervenors.

Would it be possible for New Brunswick customers to self supply ancillary services by importing them from Maine?

MR. PORTER: It would be possible from sources within the control area so northern and -- northern Maine it would be possible but it's not possible across the MEPCO tie from the rest of Maine.

Q. - The only reason I'm bringing that up is that when I look at this A-23 and I see NB Power's ancillaries listed there, I see the last column of the second row of the tables ISO NE. And I see the difference in the price of these ancillaries. And if I feel I'm going to pay for load following $67 and change or I can get load following at $36 and change, there is not much of a decision to make, that's all. I was just -- comparison wise, someone so close to New Brunswick offering a similar service.

MR. MARSHALL: We can explain, it is an issue of the whole reliability structure of the North American system is set up by NERC and the regional councils essentially is the control area philosophy. And each control area has to provide all of its own regulation and maintain its frequency at the inter-ties between the control areas.

So it is not possible to export the frequency control and regulation and load following from one control area to another because the purpose of the control areas is to balance all the load in that control area and meet their obligations separately. And it is part of the reliability structure of the North American system. That's why you can't purchase these services outside the control area.

Q. - Can I just confirm then, Mr. Marshall, that in New Brunswick, New Brunswick customers can't buy from ISO any but they can buy from northern Maine?

MR. MARSHALL: They could buy from northern Maine. They could buy from Maritime Electric. They could buy from Nova Scotia Power. They could buy from WPS Energy Services. Any -- they could buy from any generators located inside the Maritime control area.

Q. - Can you just clarify the boundaries of the Maritime control area just for everyone else?

MR. MARSHALL: The -- I believe Mr. Snowdon did it in the first day in an exhibit. The presentation shows a map. It's page 9 of exhibit A-7.

Q. - Mr. Marshall, I'm fine with that. I mean, you have done it already.

MR. MARSHALL: Just so you get it on the record and then it -- you could look at the diagram. It includes New Brunswick, Prince Edward Island, Nova Scotia and the two isolated pockets of northern Maine up in Aroostook County and down in Washington County. Those two isolated pockets of Maine which are interconnected only into the New Brunswick system and isolated from the rest of the eastern interconnection. That comprises the Maritime control area.

Q. - And that's the only reason why I had raised the issue was to have it tied in with this. That's it. Thank you, Mr. Marshall.

Mr. Porter, would you have before you A-24, comparison of transmission bill to the current bundled bill for hypothetical wholesale customer. I believe it's based on a 100 megawatt system. It was based on an undertaking by Saint John Energy to NB Power previously.

MR. PORTER: Yes, I do.

CHAIRMAN: Sorry, Mr. Young?

MR. YOUNG: It was A-24. Just a single page undertaking.

Q. - Mr. Porter, the exhibit is a response to our request to clarify how the proposed tariff will affect the cost of existing customers of distribution utilities. The response goes a long way. And it would be helpful if you could confirm two things.

Firstly, could you confirm that if as a result of the OATT coming into effect, the customer's wholesale bill were to be unbundled, the present demand charge of $9.96 per kilowatt month would be replaced by two charges, one of $3.11 per kilowatt month for transmission and ancillary services and the other for $6.85 per kilowatt month for all demand items not covered under the OATT?

MR. MARSHALL: If the rates remain the same.

Q. - Thank you. And secondly, when the last note at the bottom of the page says that tariff with ancillaries, column (g) is included in total bundled cost, column (f), could you confirm that it is 100 percent of column (g) and that it is included in column (f)?

MR. PORTER: Yes. I can confirm that column (g) is included within the total bundled cost which is column (f).

Q. - Mr. Marshall, just to follow up on a question, you said if the rates stay the same. Would you follow up on that, if the charges stay the same? Was there going to be a change?

MR. MARSHALL: This is based on the current demand charge of 9.96 in the bundled rate to wholesale customers. The tariff application before this Board is $3.11 per network service including ancillaries.

So if those two rates stay the same then the unbundled rate for the remaining service would be 6.85. If either one of those two numbers change then you will get different numbers. But the two should add up to be whatever the total bundled rate is.

Q. - What would be the reason for either one of those two numbers changing?

MR. MARSHALL: Well, first of all the Board may not approve the 3.11. So subject -- we have to wait until the decision comes in exactly what is approved by this Board. That could change. And the 9.96 is the current rate. That -- in the future that rate could change.

MR. YOUNG: That is it for my questions. Thank you, Panel C. Thank you, Mr. Chairman.

CHAIRMAN: Mr. Marshall, I wonder if you could do something for me. If you look at JDI 3 which is the New Brunswick energy policy and if you look at -- I will wait for you to get that -- page 18, 3.1.3.4, "Leveling the Playing Field."

At law we have a concept called the reasonable man. It hasn't become the reasonable person yet, to my knowledge. But anyhow I consider myself to be a reasonable man when I'm reading that.

And from that I get the very distinct impression that at the time of the White Paper when they talked about leveling the playing field, government was talking about the wholesale electricity market alone, and that's all they were talking about.

In the description that you have given to us on four or five different occasions, it's leveling the playing field between all energy sectors, so that -- and that was one of the reasons that was given that there would be payment in lieu of taxes for transmission, et cetera.

Could you, by the time we come back together again tomorrow, find where government has enunciated that difference?

MR. MARSHALL: I think it is actually in different parts of this document. Here the "Leveling the Playing Field" deals with a competitive wholesale market. That's the competitive wholesale market for electricity. But electricity is one energy form. So that level playing field still has to relate to the gas markets, gas --

CHAIRMAN: Okay. I understand that is what you have said to us on a number of occasions.

MR. MARSHALL: So that is there. And other places in this White Paper where there were issues of environmental, in a couple of the other areas, I could undertake to find them.

CHAIRMAN: Would you do that? Because this is where -- of course it is indexed under this, "Leveling the Playing Field." And that is what I had read. I would appreciate that.

We will adjourn then till tomorrow morning at 9:30. Mr. Hashey?

MR. HASHEY: Mr. Chairman, I just wonder if this wouldn't be an appropriate time, since we have a few minutes, rather than interfere with tomorrow and give you some time to reflect and make some decisions.

We will complete Panel C tomorrow. That's obvious. We are then scheduled to return here on the 6th of January to have the evidence of -- I guess at that time it would just be the panel of J.D. Irving.

CHAIRMAN: Mmmm.

MR. HASHEY: On the 20th of December we receive the presentations. We get our Christmas present this Friday. And I assume that those presentations will be following the same course of just explaining the evidence like we did. And if that is the case there is no problem.

There did become an issue before. There was time to deal with the issue. Obviously there won't be time to deal with that issue. And I assume if there is an issue we come back on the 6th and discuss it. I don't see really any other opportunity frankly.

CHAIRMAN: No. You are right. Christmas and New Year's are out of bounds.

MR. HASHEY: Yes. No, that's fair. So on that basis. Then after that -- we anticipate that that evidence will not be but for a couple of days possibly. Then there might be some rebuttal but it would be short.

So that we are not going to use up a lot of time in the two weeks that are set aside. You probably hear now where I'm coming from.

There will necessarily be presentations to the Board by ourselves and the Intervenors on what we think should happen here.

CHAIRMAN: Mr. Hashey, let me tell you, the Board has been talking a good deal, particularly in the last week. It would be our intention, subject to whatever the parties have to say, that if the legislation has not been tabled by the time we conclude the evidence, that we would adjourn sine die until such time as that legislation is in the House and we have all had an opportunity to read what it is that the government is saying.

I want to assure you, the applicant's solicitor and the other parties that the Board is very cognizant of the date of the 1st of April of 2003. And as is the case, we could if necessary simply issue our decision with written reasons to follow later if the time dictates that kind of a move.

But certainly, speaking for myself and my fellow Commissioners, we want to see that legislation before we hear from the parties and before -- and then give our decision after that.

And again that is subject to -- I mean, it may come down this week. We don't know. If some people stop talking it might. I don't know.

Or I don't know when the House is supposed to come back in. Mr. Knight, do you know? Is it going to be the 6th or is it --

MR. MORRISON: I believe it is the 7th, Mr. Chairman.

CHAIRMAN: They are coming back on the 7th I think.

MR. MORRISON: My understanding.

CHAIRMAN: So it could very well be that it would be available for us to look at. So all of that having been said, just simply -- I know you are trying to get a sense of when it is we would have summation and what form it would take and that sort of thing, Mr. Hashey.

I think we are at the mercy of the House as to when we set our time for summation, et cetera.

MR. HASHEY: Okay. That's very fair. And I thank you for the comments. Obviously we have no idea, sitting here, any of us that I know of, have any idea when any legislation might be tabled.

CHAIRMAN: We all have estimates I guess. But that is about all.

MR. HASHEY: I don't even have that. But that is me.

CHAIRMAN: Mr. Marshall, do you have any estimates?

MR. MARSHALL: Estimates of when the legislation is coming down?

CHAIRMAN: I guess not. I guess not. We were talking about when the legislation might hit the House. That is a good pool, isn't it?

MR. MARSHALL: I would say it would be a pool that we could all bet on. At this stage I don't have any definitive information as to when the legislation is coming down. I don't think anybody in the room does.

CHAIRMAN: Mr. Hashey, let us say it was tabled the first week of January before we concluded. The Board's normal approach to these matters, as I think you are aware, would be to take a day or two off between the closing of the evidence and then come back for oral summation.

We don't -- normally don't call for written briefs unless there is a point of law that needs to be canvassed, and then take a break between I would say your summation in chief, everybody, so that we can then consider what all the parties believe to be important issues.

And the Board can look at that and then come back and say to the parties, will you in your rebuttal also address the following things which nobody has covered to this point that we think are important. So therefore you are probably looking at a two-day staged oral summation.

MR. HASHEY: What I was going to request actually is -- and that's fine. That's great. I assume you don't want long written briefs. I knew that, and I assumed that.

The issue on timing, I would prefer to say have a week after we conclude the evidence. It sounds like we were going to have that anyway. Because the legislation won't be presumably down unless it happens tomorrow or something. I don't know.

But I would like a little bit of time between that time, bearing in mind --

CHAIRMAN: All right. I certainly hear that.

MR. HASHEY: That's all.

CHAIRMAN: Does anybody else have any difficulty with that? Mr. Nettleton?

MR. NETTLETON: Just so that I understand, sir, the idea is that if the legislation has not been tabled before the completion of the evidentiary portion of the hearing, then the hearing would adjourn sine die?

CHAIRMAN: That's correct. Yes.

MR. NETTLETON: And if the legislation were to then come in, we would resume the evidentiary portion of the hearing?

CHAIRMAN: That depends upon what it says. I mean, I'm not going to -- the Board has no intention of cutting off the parties.

If for instance what comes in in the legislation is dramatically different from what NB Power has anticipated it will be and we have talked about here, we may well say --

MR. NETTLETON: That is my concern.

CHAIRMAN: -- you know, offer up a witness, if you wouldn't mind, so that you can now address those dramatic changes, et cetera.

We want to have the best evidence in front of us that we can get to deal with facts.

MR. NETTLETON: Exactly. I just wanted to make sure that there was a placeholder in the evidentiary portion of this hearing if necessary, should the legislation come in following the panels that have been heard already.

And I mean, since the legislation hasn't come in yet, and if there is any matter dealing with either policy or tariff design -- well, for that matter, any of the panels now, that we would have an opportunity to have those panels return to ask any questions arising from the legislation.

CHAIRMAN: Well, I won't commit the Board to something. You know where I'm coming from and what I say personally. But we just want to have the best evidence that we can in front of us when we make that decision.

And we will wait and see what the legislation says, is certainly my approach to it.

MR. NETTLETON: I think everyone wants the best record. And then, sir, with respect to rebuttal, I just want to be clear that there would be a time following the evidentiary portion, including legislative changes, there would be a time for parties to prepare argument.

And are you ruling now that there would be no written submissions? Or is that --

CHAIRMAN: No, I'm not ruling. I'm saying normally we don't require that. Quite often counsel will come and they will have an outline of their argument that might be in writing which they will present orally and file with the Board. That's fine. Whatever --

MR. NETTLETON: Very good.

CHAIRMAN: -- your choice may be. But our experience has been that it is better to do an oral summation.

MR. NETTLETON: I agree wholeheartedly with that. Now if -- you mentioned rebuttal argument. Would that be rebuttal argument of all parties or just the applicant?

CHAIRMAN: Oh, we are talking about in the argument?

MR. NETTLETON: Yes. You indicated that there would be --

CHAIRMAN: What happens is we go around and everybody makes their argument.

MR. NETTLETON: Yes.

CHAIRMAN: And then we adjourn for a brief time --

MR. NETTLETON: Yes.

CHAIRMAN: -- be it overnight or whatever. And then we come back and we say, all right, you have heard what the applicant -- the applicant will have the last go.

MR. NETTLETON: Yes.

CHAIRMAN: But you have heard what they have said. And if you want to address something that you didn't cover in your original, then you can do that.

Plus the Board would like you to cover a number of other things that nobody has covered. Would you please address that?

MR. NETTLETON: Okay.

CHAIRMAN: So everybody gets the opportunity to go around twice.

MR. NETTLETON: Everyone gets an opportunity to go around twice? Okay.

CHAIRMAN: That's correct.

MR. NETTLETON: Thank you.

CHAIRMAN: Yes. Okay. All right. We will adjourn until 9:30 tomorrow morning.

(Adjourned

Certified to be a true transcript of the proceedings of this hearing as recorded by me, to the best of my ability.

Reporter