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 17th 2002, 9:30 a.m.

CHAIRMAN:	David C. Nicholson, Q.C.
COMMISSIONERS:	J. Cowan-McGuigan Ken F. Sollows Robert Richardson Leon C. Bremner
BOARD COUNSEL:	Peter MacNutt, Q.C.
BOARD SECRETARY:	Lorraine Légère

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CHAIRMAN: Good morning, ladies and gentlemen. Any preliminary matters, Mr. Hashey?

MR. HASHEY: Yes, Mr. Chairman. There is a couple of undertakings that we can respond to. One yesterday was requesting that we produce the update of the CIBC world markets ratings, Standard & Poors and DBRS. And we have that extra paper that we can now offer.

CHAIRMAN: Yes.

MR. HASHEY: This is dated December 2, 2002.

CHAIRMAN: That will be A-29.

MR. MORRISON: Mr. Chairman, there is a couple of other undertakings we are in a position to respond to.

The next one is an undertaking given to Mr. Smellie on November 19th. He wanted to know what provisions of the laws of New Brunswick entitle a party to file a complaint with this Board.

And our response to that is that Section 6 and 8.4 of the Public Utilities Act provide this Board with the authority to hear and investigate complaints with respect to violations of the tariff.

And the next undertaking is an undertaking in response to questions by Mr. MacNutt to Mr. Snowdon. And it dealt with the complaint procedure under the standards of conduct.

And if you will recall, under the standards of conduct the appeal process provided for a complaint to be sent to the president of the Transmission company. And he and the complainant would agree on an arbitrator.

And the question was "What happens if they cannot agree on the selection of an independent arbitrator?"

And our response to that is that NB Power proposes that the appeal process set out in attachment L the standards of conduct be consistent with the general dispute resolution procedures set out in section 12 which is at page 28 and 29 of the tariff. Accordingly NB Power proposes that in the event that the president of the transmission provider and the complainant cannot agree upon a single arbitrator within 10 days of the complaint being forwarded to the president, each will choose one arbitrator who shall sit on a three-member panel, the third member of which shall be selected by the two arbitrators within 20 days. And the arbitration board shall render a decision within 90 days. Such decision shall be binding subject to the appeal provisions of the New Brunswick Arbitration Act. And that will make that process consistent with the general dispute resolution procedure as set out earlier in the tariff.

CHAIRMAN: Thank you. Any other matters? If not -- I see that Mr. MacDougall is here representing WPS energy after a long absence, as it were.

Mr. Nettleton?

MR. NETTLETON: Mr. Chairman, good morning. Commissioners, good morning. Two preliminary matters arise.

First with respect to the undertaking that was given which has been given the exhibit of A-23, I have advised my friend Mr. Morrison that both CME and JDI intend to cross examine on this undertaking. We are though in need of the backup data that was used to create that undertaking and exhibit.

And my friend Mr. Morrison has undertaken to provide that for us. That information is in process of being provided. And if I don't finish today, which I think I will -- but if we haven't had a chance to review that information, we will be back likely tomorrow to touch on that matter.

The second matter is Mr. MacDougall has informed me that as an urgent family matters arises with his client, he has asked if he could cross examine at this point in time. I have no problems with that, sir.

CHAIRMAN: The applicant all right?

MR. HASHEY: That is fine.

CHAIRMAN: Mr. MacDougall, go ahead.

MR. MACDOUGALL: Mr. Chairman, thank you very much. I would like to start by thanking JDI and its counsel for accommodating us in this regard. It is something that is important to Mr. Howard.

I did mention it to Mr. Hashey at the beginning as well. I apologize. I hadn't had a chance to talk to Board counsel before the Board came in.

CHAIRMAN: Okay.

MR. MACDOUGALL: I'm joined today, Mr. Chair, with Mr. Ed Howard who is an energy marketing executive from WPS

Energy. And you will indulge me if I turn to him once in awhile on a couple of the technical answers.

I would also at the outset like to note that, as you mentioned at the beginning, Mr. Chair, we have not been here throughout. We have reviewed the transcript at least in part.

We will try not to duplicate any questions and use any extra time on issues that have been dealt with. But because we haven't been here throughout the whole process, if we do duplicate a few questions, I hope you would bear with us.

CROSS EXAMINATION BY MR. MACDOUGALL:

Q. - Good morning, panel. Our questions today really deal with the rate schedules. And I think it will be important to have the tariff rate schedules in front of everybody as well as the tariff design document which is appendix B I believe to Mr. Porter's testimony.

CHAIRMAN: Is that A-2 or A-3?

MR. MACDOUGALL: A-2, volume 1 of 2.

Q. - And although I will be referring to other documents throughout, I think it would be useful to keep the tariff design document handy throughout this cross examination.

Again, I am unsure who is going to be able to respond to the question, so for most of my questions I think I will just put them to the panel. I believe it will probably be Mr. Porter and Mr. Marshall in most instances.

At page 24, if you could turn to page 24 of the tariff design document. In the last paragraph, under the heading entitled "Energy Control Centre Assets", it is stated that the energy control centre assets support the operation of the transmission system. And then it goes on to say the allocation was based on an assessment of the usage of the NB Power control centre building, computer systems and other related equipment required for system operator functions.

These are the functions that are to be charged under the tariff through the service called scheduling system control and dispatch.

However, when you were asked by WPS whether there was a time study done in relation to this aspect of the tariff, you stated there was no time study. And this is your response to WPS IR-11. And that the allocation was based on the ratio that was utilized to allocate OM&A for the purpose of sharing services.

So can I take it that the assessment you are referring to here was essentially your rationale for how you allocated OM&A for the purposes of sharing services?

MR. PORTER: What was done in terms of determining what portion of the energy control centre assets would be allocated to transmission versus to distribution was to look at the total OM&A and use the proportional breakdown of the OM&A expenses to apportion the assets.

So the OM&A was determined by looking at each cost centre within the energy control centre budget. And for each of those cost centres, determining what the allocation of transmission would be and what the allocation to distribution would be.

So then the total transmission dollars divided by the total ECC dollars for operation, maintenance and administration, that ratio was used to allocate out the assets at the energy control centre.

Q. - So when you go back to the bottom of page 24 and you say the allocation was based on an assessment of the usage of the NB Power energy control centre building, et cetera, that is the assessment you are talking about?

MR. PORTER: That is correct.

Q. - Thank you. So if we can go to table 3.2, which is on the next page, page 25, the number of 4.4 million, which is across from the reference to energy control centre, this is some split of the OMA, OM&A for the energy control centre assets, which is attributable to transmission?

MR. PORTER: That is correct.

MR. MARSHALL: I would add plus the capital related costs of all of the assets and the OM&A. So it is the sum of the capital related costs and the OM&A attributed to energy control centre allocated to transmission.

Q. - So you have not done any specific time accounting that would specifically reflect the operator's time spent on transmission operations as opposed to generation or distribution operations. Is that correct?

MR. PORTER: I believe the work that was done was an interview with the respective managers and asking them to evaluate what proportion of time was spent by their group on each of the two functions.

MR. MARSHALL: I might add to that. The operators at the energy control centre, there are two distinct operating rooms. In one room there are only operators dealing with transmission functions. And in the other room there are only operators dealing with distribution functions.

So essentially 100 percent of the operators in one room are transmission and 100 percent of the operators in the other room are distribution. It is the split of the overhead costs and the building assets that is at issue.

The O&M costs related to distribution and transmission are clearly delineated at energy control centre.

Q. - Which group does generation?

MR. MARSHALL: In the main control room, the energy coordinator would be the dispatcher of the generation to operate the system and ancillary services. The transmission operator in the control room would do the switching of transmission functions and the reliability functions.

They are both in the same energy control centre transmission system operations control room as opposed to the distribution operations control room.

Q. - Thank you. I guess what I am coming to and I am going to have to just revise my questions a little bit here, is to come back to your response to WPS IR-1. Because you said the allocation was based on the ratio that was utilised to allocate OM&A for the purpose of sharing services. And I couldn't find anywhere where there was a figure that represented that, except with respect to the 12 percent that you are using for overall OM&A.

So could you maybe explain to us what you mean by it was based on the ratio that was utilized to allocate OM&A for the purposes of sharing services?

MR. PORTER: I think a better way to put that would be that the ratio of the OM&A, that is the transmission OM&A versus the total, which is two-thirds of the total OM&A costs, that ratio was used to allocate out the assets and the associated revenue requirements.

Q. - So you are saying it is two-thirds?

MR. PORTER: Yes.

Q. - Is the figure.

MR. PORTER: That is correct.

Q. - Could you tell me where that was referenced in any of the documents?

MR. PORTER: I don't believe that is in any of the documents.

Q. - Thank you.

MR. PORTER: That is in our supporting documents.

Q. - Is it in supporting documents filed with the Board?

MR. PORTER: No.

Q. - Do you have or do you propose to have an account that shows operator time allocation for transmission operations?

MR. MARSHALL: We are ready to respond.

Q. - It wasn't meant to be that difficult a question. Sometimes the answers are more difficult than the question.

MR. MARSHALL: I just wanted to check with the comptroller in terms of accounts. You are asking about accounts. There is only one group that we are aware of, energy control centre, that would be performing functions that would relate to both distribution and transmission. And that would be the computer group at the control centre would maintain and do the computer systems that the distribution operations control room work on, as well as the transmission operations control room.

But all of the people associated with operating the transmission system, being the full energy coordination group, the transmission reliability group, all of those groups are -- would be 100 percent transmission. The distribution operations people would be 100 percent distribution. The only sharing between OM&A would be the computer group SCADA, data collection group that provides some services to both.

That's our understanding but subject to check with the control centre management that we believe is correct at this time.

MR. PORTER: I would add to that. I think there are some -- additionally some administration services that are shared. That would be the only -- the additional thing. But that would be minor.

Q. - Mr. Chair, if you would beg my indulgence one more time, because we did move up early this morning. I have one document that I'm going to refer to but was going to make copies at the break. But since we have moved up, I don't have copies of it. I'm going to make reference to it. If there are any issues with it I'm sure people will raise the issue and I will try and get the other copies made, but we may not need to have to do that, but I want to apologize in advance.

CHAIRMAN: Go ahead.

Q. - Where I'm going with this I guess is is anyone on this panel familiar with the operation and maintenance expense accounts that would be utilized at FERC, their standard forms? Just in general.

MS. MACFARLANE: Representatives from NB Power in the finance function have reviewed them and have reviewed that we can meet FERC reporting requirements if necessary, but neither of the two panels representing accounting, shall we say -- neither of the two witnesses on the panel are familiar with FERC accounting ourselves.

Q. - If I could, Mr. Chair, I'm just going to read from a couple of references from the FERC document and then we will make the document available as well.

CHAIRMAN: Mr. MacDougall, I have a question of you.

MR. MACDOUGALL: Certainly.

CHAIRMAN: I guess it was last week or the last panel I inquired if NERUC had a system of accounts. I know CANPUT does not, the Canadian regulators. And so the FERC system of accounts is the first uniform system of accounts that I have become aware of. Are you aware of any others, other than the FERC, Mr. MacDougall?

MR. MACDOUGALL: For electricity matters?

CHAIRMAN: Yes. For transmission companies.

MR. MACDOUGALL: I am not specifically aware of any. I am hearing from the back row that others may be aware of some.

CHAIRMAN: Well we would be -- the Board would be interested in hearing about if there are some. Anyway, sorry to interrupt. Go ahead.

MR. MACDOUGALL: No, that is no problem. I am sure some of my colleagues will bring that up if they have other documentation. We are aware of the FERC system of accounts.

And Mr. Chair, they are --

MR. PORTER: If I could interject in terms of our response to that undertaking to investigate whether or not NERUC has such a set of accounts. Our response included the information that we are only aware of the FERC uniform set of accounts.

And that we talked to other Canadian utilities and also some American utilities. And the information that we got is that even though the U.S. utilities are required to report on that standard set of accounts, they do not -- that is not their primary set of accounts and it is not the set of accounts to which they manage. So it is really an additional layer of accounting.

And secondly, for Canadian utilities, the Canadian utilities, all the ones we have talked to have indicated that -- they determined that they did not require or choose to use the FERC standard.

In fact, Manitoba Hydro, who has strong connections with transmission services in the U.S. is able to offer services without having that standard set of accounts. It hasn't been a problem for them.

So to this point we do not propose it unless it is something that is required. And that was the response that we gave to an undertaking a week or two ago.

CHAIRMAN: Thank you.

Q. - Mr. Chair, I will just read from a couple of passages here. And this is the FERC Federal Energy Regulatory Commission Department of Energy operation and maintenance expense accounts, which we will provide to everybody.

Account 560, operation, supervision and engineering, the first statement, panel, is "For major utilities, this account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of the transmission system as a whole." So that is 560.

And then account 561. "Load dispatching - This account shall include the cost of labor, materials used and expenses incurred in load dispatching operations pertaining to the transmission of electricity."

So both paragraphs 560 and 561 deal with transmission.

Then if you go to paragraph 580. Operation, supervision and engineering. "This account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of the distribution system."

And 581, which is the matching section. "This account, the keeping of which is optional with the utility, shall include the cost of labour, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity."

And one final item, account 556. "System control and load dispatch. This account shall include the cost of labor and expenses incurred in load dispatching activities for system control utilities having an interconnective electric system or operating under a central authority which controls the production and dispatching of electricity."

So again, without the document in front of you, although I can put this copy in front of you, would you agree that the FERC operation and maintenance expense accounts do appear to call for accounts that would break up the transmission, distribution and generation or production functions for the purposes of accounting?

MR. MARSHALL: Yes.

Q. - Thank you.

MR. LAVIGNE: Although we are not following the FERC guidelines, our system of accounts does allow for a similar, I guess, apportionment of the costs. We do have a structure, accounting structure, which provides a breakdown between the transmission system ops and the distribution system ops.

Even within the transmission side, we can I guess divide up those two other functions that you mentioned.

Q. - You have just said that you can do that. Do you propose to do that?

MR. LAVIGNE: We currently do it at this stage in time.

Q. - Thank you. Now rate schedule 1, which is scheduling system control and dispatch, is a mandatory service, correct?

MR. PORTER: That's correct.

Q. - And as a mandatory service, do you think that NB Power should be attempting to determine as accurately as possible the true cost of this service?

MR. PORTER: Agreed. I might add we believe we have an accurate representation of that figure.

Q. - Is there anything that would prohibit you from conducting a specific time study with respect to this functional element?

MR. MARSHALL: We have already responded that the entities, the operators that carry out the transmission functions are 100 percent, the time is 100 percent allocated to transmission. It's already done today in all the accounts.

So what specific aspects of the energy control centre operation would you want us to sort out the time? The time the secretary spends answering the phone in relation to a distribution call versus a transmission call? The time that the manager spends dealing with the distribution group or the transmission group? Because those are the only -- and the time that the computer group spend dealing with distribution or transmission.

Those are the only entities I see that have any time allocation involved.

Q. - I guess, Mr. Marshall, then maybe what I could ask you to do is you talked about a ratio earlier. And you used that ratio to come up in part with your $4.4 million figure for the energy control centre.

Possibly you could undertake to provide the supporting information that shows the breakdown of that ratio so that the Board is able to clearly understand that all of the functions for energy control centre related to transmission are discretely set out.

MR. MARSHALL: We can undertake to do that.

Q. - Thank you.

MR. MACDOUGALL: I'm getting rid of some questions, Mr. Chair.

Q. - Now if we could turn to page 65 of the transmission tariff design document, schedule 2.3.

MR. PORTER: Yes. We have it.

Q. - If I look in column 1 but at the bottom of --

CHAIRMAN: Schedule 2.2?

MR. MACDOUGALL: 2.3, Mr. Chair.

CHAIRMAN: We don't have 2.3.

MR. MACDOUGALL: Page 65. Mr. Chair, this document has two groups of schedules in it. So it is confusing. So you have to follow the page reference. It is page 65. Because there is another schedule 2 somewhere else.

CHAIRMAN: This is the first time that we have become confused that way. And the regulatory group from NB Power are to be congratulated for the way in which they have organized it this time in comparison to previous. It is a lot clearer.

So carry on, Mr. MacDougall.

MR. MACDOUGALL: No problem, Mr. Chair. I was ready with the answer because I did know there were two schedules.

Q. - So at the bottom of that -- in the bottom line, it is the line on the far left side that says "Schedule system control and dispatch for network service."

In column 1 you are showing the cost of service of $1.43 per kilowatt year, correct?

MR. PORTER: That's correct.

Q. - And that essentially -- if you go up to the first line where you show "Schedule system control and dispatch", generally that would equate to the column 3 number there of $1.43 per kilowatt hour year, correct?

MR. PORTER: Correct.

Q. - And essentially that would also equate to the reference under "System control and dispatch for point-to-point yearly" in the column $1,430 per megawatt year, correct?

MR. PORTER: That's correct.

Q. - So for network service you start with the same cost of service for the function as for point-to-point service?

MR. PORTER: That's correct. On a coincident basis the cost allocation is identical.

Q. - So the starting point?

MR. PORTER: That's correct.

Q. - However you then apply a coincidence factor of 81.7 percent. Again we are down in the bottom line, "Schedule system control and dispatch for network service."

So that the monthly rate for network service is then some 19.3 percent less than for point-to-point service, correct?

MR. PORTER: That's correct. That is because the billing determinant there, as Mr. Marshall had talked about in his presentation, is the noncoincident peak demand, whereas the allocation is done based on coincident peak demand.

Q. - Exactly. So my understanding is that the 81.7 percent is the ratio between 2,100 megawatts, which is the network usage on the average of 12 monthly coincident peaks on the system, to 2,571, which is the billing based on noncoincident peaks?

MR. PORTER: That is correct. The 81.7 percent allows a conversion from the coincident numbers to the noncoincident numbers.

Q. - But the cost to provide this service is the same whether it is point-to-point or network service, correct?

MR. PORTER: That's correct.

Q. - How do you know that the ratio between coincident and noncoincident peaks will remain the same for the duration of the term of this tariff?

MR. PORTER: We don't know that it will remain identical. But we have no reason to suspect it would change significantly. The rates are designed based on the test year information. And that is the case throughout the study.

Q. - If it doesn't remain the same won't there be a cost over or under collection relative to the actual cost of providing the service?

MR. PORTER: That's correct. But that is a relatively minor factor relative to the volume risk. And of course any over collection or under collection is also addressed by the PBR mechanism as we have discussed previously.

Q. - So this would be credited through the PBR mechanism or debited?

MR. PORTER: Credit or debit, yes.

Q. - How do you derive the 2,100 megawatts?

MR. PORTER: The response to that question is contained in a response to an Interrogatory. It was based on an extrapolation of three years of history.

So we took three years of actuals and examined that to produce the forecast for the test year.

Q. - So you are comfortable with your 12 CP figure?

MR. PORTER: Yes.

Q. - Are you aware of the method of using noncoincident billing determinants for network service as used in the FERC or any FERC-compliant jurisdiction?

MR. PORTER: It is my understanding, and it is indicated in the Rudden Report which is contained within our evidence, that such an approach was used within the state of Maine and accepted -- I believe accepted by FERC and certainly accepted by the state regulator. And that is for retail loads connected to the transmission system in the state of Maine.

Q. - Noncoincident peak?

MR. PORTER: That is my understanding. And the reason being that there are loads that don't have coincident peak metering, and therefore noncoincident peak demands are used.

Q. - And is that your understanding, or your understanding from the Rudden Report?

MR. PORTER: That is my understanding from the Rudden Report.

Q. - Just to stop there, because we have a question on that, and I didn't think it would arise at this time. But is there anyone here or going to be here to speak to the

Rudden Report?

MR. PORTER: We are here to respond to questions on the Rudden Report, this panel.

Q. - Mr. Garwood isn't being put up, the author of the report or anyone from Rudden?

MR. PORTER: No.

Q. - Is there any specific reason for that?

\ MR. PORTER: The document in the evidence contains -- is a summary of Rudden's evaluation. It is comprehensive. And we believe it is clear and been available to the Board and to Intervenors.

And believe that that addressed our needs in terms of providing an external evaluation, particularly with respect to FERC's -- our compatibility with FERC standards. And to this date we haven't had any request for such an appearance.

Q. - But it constitutes evidence in this proceeding?

MR. PORTER: Yes, it does.

Q. - And the author of it isn't available for cross examination on it or hasn't been put forward for cross examination on it?

MR. PORTER: No, he has not.

Q. - I might come back to that topic in a second again.

Are you aware of any tariffs recently filed before the

FERC, let's say in the last 18 months or so, where there has been a differential between network and point-to-point service?

MR. PORTER: I have no familiarity with any tariffs have been filed with FERC within the last 18 months of any type.

Q. - Would Mr. Garwood, do you think?

MR. PORTER: I can't answer that question.

Q. - You have put his report forward though as an expert on compliance with FERC tariffs. So do you think he would have an idea?

MR. PORTER: There is a good chance that he would have that information. But keep in mind that Mr. Garwood's evaluation was based on the understanding that our goal was to produce an Order 888 type open access transmission tariff.

And there have been six years of jurisprudence there of which he is very familiar and was fully up to date and informed on those precedents and able to make his evaluation based on that.

Q. - So you couldn't --

MR. MARSHALL: I might add to that that the intention here was to file this tariff with respect to the regulatory jurisdiction of this Board in New Brunswick.

We have worked hard to make this tariff as compatible as possible using the principles of FERC, to be compatible with FERC Order 888.

Where there are -- may be some minor deviations that may or may not meet FERC's absolute requirement, they are done under the policy direction of the market design committee in New Brunswick and the review in the circumstances of New Brunswick.

And it is within the jurisdiction of this Board to then accept or not accept the proposal.

Q. - Would you be able to agree or disagree, and maybe you won't be able to, that the recent trend before the FERC is to move towards a network rate and to allow for locational marginal pricing more than point-to-point service?

MR. MARSHALL: You are referring to the SMD NOPR?

Q. - In general or just the general trends before the FERC?

MR. MARSHALL: There is an evolutionary trend in that direction. And that is somewhat included in the SMD NOPR. Again it is a NOPR. It is part of a long evolutionary process of regulatory change. At some point in time that may come about as it is in the NOPR. And it may not come about as it is in the NOPR.

And just for the record, I think we have talked about NOPR. NOPR is Notice of Proposed Rulemaking, NOPR.

Q. - Thank you, Mr. Marshall.

MR. PORTER: Subject to check, but I believe that the NOPR, in terms of the billing determinant, is a bit open-ended, is my recollection. But we could check on that.

Q. - No. I think that's okay.

Who do you anticipate to be the biggest user of network service in the initial years of your tariff?

MR. PORTER: It would be the NB Power Customer Services.

Q. - Is that NB Power Distribution?

MR. PORTER: Yes, that's correct. Yes.

Q. - All of a sudden I thought there was another entity here.

CHAIRMAN: Another butterfly.

MR. PORTER: It's NB Power Distribution and Customer Service.

Q. - And Customer Services, thank you. If you could just bear with me one second, Mr. Chair.

Mr. Porter, we have been having a difficulty finding the reference to anything about Maine in the Rudden report. Could you maybe assist us in that regard?

MR. PORTER: Sorry, I missed the question.

Q. - We have been having a difficulty finding any reference to what occurred in Maine with respect to this issue and the noncoincident peak billing determinants in the Rudden report.

MR. PORTER: Oh, okay.

Q. - We don't have to do it right now.

MR. PORTER: Sure. Yes.

Q. - If it's going to take time, whatever is more convenient for you. Maybe at the break and we could just after the break --

MR. PORTER: Okay.

Q. - -- you could show us the reference? I would like now to turn to rate schedule 2. Yes, 2, please.

CHAIRMAN: Could you be a little more precise?

MR. MACDOUGALL: Certainly, Mr. Chair. It's part of the transmission tariff document itself. It's exhibit A-3, Volume 2 of 2.

CHAIRMAN: All right. We have got A-3. Where is it in A-3?

MR. MACDOUGALL: It's the tariff document, Mr. Chair, schedules 1 to 9. It's tab schedules 1 to 9.

CHAIRMAN: Okay.

MR. MARSHALL: Page 85 of the tariff, Mr. Chairman.

Q. - Now rate schedule 2 is reactive supply and voltage control. This is your other mandatory service, correct?

MR. PORTER: That's correct.

Q. - Now if we could turn to attachment J -- maybe not. Maybe I can just reference this I think without having to turn too often.

Attachment J is your generation interconnection agreement. And it's attachment J to the tariff. And at page 197 under the section entitled, Voltage or Reactive Control Requirement, you state, "That unless otherwise agreed to by the parties, customer will operate its facility with automatic voltage regulators consistent with Schedule B." Is that correct?

MR. PORTER: That sounds correct.

Q. - So as part of the generation interconnection agreement the customer will operate its facility with automatic voltage regulators consistent with the schedule in that agreement?

MR. PORTER: That's correct.

Q. - And also in that section it states at line 25, if Mr. Marshall has it there, compensation to customer if any for providing such reactive power and voltage support will be in accordance with applicable provisions of the tariff or any applicable market rules and procedures. Correct?

MR. PORTER: That's correct.

Q. - So if we could now turn to page 259 of the tariff. And page 259 of the tariff is actually in -- that page is in Schedule B of the generation interconnection agreement.

So under the heading, Reactive Capability, the first sentence reads, "All synchronous generators shall be rated to operate continuously at maximum rated power and at any power factor between 90 percent lagging and 95 percent leading with plus or minus 5 percent of rated voltage." Correct?

MR. PORTER: Yes.

Q. - Now the fact that there is a plus or minus 5 percent variation band does not in any way affect the mandatory requirement for transmission customers to pay for reactive supply and voltage control, does it?

MR. MARSHALL: No. This is the -- the reactive capability of the generator in the generator interconnection agreement.

Q. - Correct.

MR. MARSHALL: It's not tied to a customer's requirement to pay for reactive supply and voltage control.

Q. - Which is a mandatory requirement?

MR. MARSHALL: Which is a mandatory requirement, yes.

Q. - Thank you. Now if we could turn to page 50 of the tariff design document. At line 9 it states as follows, "The pricing for reactive supply and voltage control, Schedule 2, is determined from the proxy unit cost of supplying it, and the quantities required in a manner similar to capacity based ancillary services." Correct?

MR. PORTER: Correct.

Q. - And I don't think you have to turn this up, but I'm just going to reference in response to Saint John Energy's IR 66 where you were asked to explain why the use of proxy units for ancillary services produces a more appropriate price, you indicated that NB Power had reviewed various methods including embedded costs, short run marginal costs, bid based, and long run marginal cost proxy units. Is that correct?

MR. PORTER: Yes.

Q. - Can you advise the Board or are you aware of any FERC approved compliant tariffs to which reactive supply and voltage control is based on a proxy unit basis?

MR. PORTER: No. And we responded to that effect in an IR from WPS.

Q. - Now if we can turn to the second page of your answer to Saint John Energy's IR 66. So that's, Mr. Chair, Volume 1 of 2, the response to interrogatories.

CHAIRMAN: Exhibit A-4.

MR. MACDOUGALL: IR 66, exhibit A-4.

CHAIRMAN: Page?

MR. MACDOUGALL: Saint John Energy. Page 544, Mr. Chair.

CHAIRMAN: Thank you.

Q. - Mr. Chair, if you will just bear with me. I'm just going to read the last two paragraphs of that page 544 into the record.

"The system specific nature of embedded cost pricing conflicts with the procurement of ancillary services on a competitive basis. The embedded cost analysis can produce results that are higher or lower than the cost of a competitor and thus be either uncompetitive or present a barrier to new providers respectively. Initially the provision of ancillary services will be dominated by NB Power Generation due to the limited alternatives. Therefore the use of embedded cost pricing would inherently make NB Power Generation cost data public knowledge. Detailed cost data would need to be requested from NB Power Generation. The documents information that would be requested contain information that would be of commercial value to competitors of NB Power Generation and is by its nature confidential. The release of such information would cause financial loss to NB Power and financial gain to its competitors. For these reasons NB Power objects to providing such material requests."

Now is it your position that embedded cost pricing is not utilized in other FERC compliant tariffs where there is open market competition? For example, NEPOOL in Pennsylvania?

MR. PORTER: No, that's not our position.

Q. - In fact is it your understanding that the majority if not --

MR. PORTER: Sorry. Could you -- sorry, could you repeat that question?

Q. - Yes. the question was is it your position that embedded cost pricing is not utilized in other FERC compliant tariffs where there is open market competition such as NEPOOL of Pennsylvania?

MR. PORTER: No. Those -- the pricing in those areas are based on bid based pricing.

Q. - And does the cost data for the generator's rate schedule 2 have to be provided to the FERC? Or let's put it this way. Doesn't the cost data for the generator's rate schedule 2's in those marketplaces have to be provided to the FERC?

MR. PORTER: I'm sorry, a correction here. You are referring to those markets for that particular service?

Q. - Just we are talking now about this rate schedule?

MR. PORTER: Okay.

Q. - Sorry.

MR. PORTER: Make a correction then. It's not bid based and I can only -- I'm not that familiar with it but I would assume that it is based on some form of cost information that gets filed with FERC.

Q. - So could you confirm that the majority if not all of FERC compliant tariffs for this rate schedule would be based on either embedded costs or an allocation method demonstrating the percentage of generation attributable to the VAR support and the generator step-up unit attributable --

MR. PORTER: I believe that to be the case.

MR. MARSHALL: Just a correction on that. We do not believe that the generator step-up unit would be attributed or costed against that ancillary service. The generator step-up unit would be a direct assignment charge specifically charged back to the generator in total. A piece of it may be related to that service. But a large portion of the generator step-up unit would go to energy and be -- be a competitive source in the marketplace.

Q. - A percentage of the step-up unit then. Thank you, Mr. Marshall. I told you I would need technical advice at times, Mr. Chair.

Now on page 545 of your answer to Saint John Energy under the heading Proxy Pricing, you state at the -- I believe it's the third sentence that, "Proxy pricing is also transparent in that data is available to all parties to assess the validity of the cost analysis." Correct?

MR. PORTER: That's correct.

Q. - But the data provided is data on the proxy unit, right?

MR. PORTER: That's correct.

Q. - So isn't transparency not supposed to reflect actual cost? What is transparent about providing the costs of a proxy unit?

MR. PORTER: The point there on transparency is that -- that these are not units which are specific to a particular system or a particular site or particular installation. So any market participant or someone familiar with the industry could go out and evaluate costs and come up with a -- presumably they will come up with a very close to being the same figure. That's what was intended by the statement that there is transparency.

Q. - But they would get the transparent cost of the proxy unit as opposed to the transparent cost of the provision of the service or the cost of the service by the utility?

MR. PORTER: What they would have would be a transparent evaluation of the cost of the proxy unit.

Q. - Thank you. Now as we have already discussed your approach to pricing ancillary service number 1, scheduling system control and dispatch which is also mandatory, was based on an embedded cost approach, correct?

MR. PORTER: That's correct.

Q. - So you have no general bias against using embedded costs.

In fact your transmission tariff as a whole is based on embedded costs?

MR. MARSHALL: That's correct. The transmission tariff is based on the embedded costs of transmission assets and the transmission system which is 100 percent regulated cost of service business and the jurisdiction of this Board.

The issue with generation related ancillary services is that it would publicly make available to all competitors of NB Power Generation its detailed costs of all of its assets and competitively disadvantage it in the marketplace, potentially causing commercial loss. That's why that information is not made available.

Q. - The ancillary services schedules you have to file, NB Power Transmission, are regulated by this Board, correct?

MR. MARSHALL: Yes, they are. That's -- we have proposed proxy units as reasonable pricing of those services for this Board to rule on.

Q. - And do you think this Board has a right to see the cost information on which this pricing is based, if it desires to obtain that?

MR. MARSHALL: That information is all laid down in the schedules.

Q. - Based on proxy?

MR. MARSHALL: Yes.

Q. - Okay. To get to your point on NB Power Generation then, has NB Power Generation agreed that these costs are sufficient to cover their cost of providing this service?

MR. MARSHALL: Yes. This is an application as we have said before, before this Board as an integrated corporate utility. The application has been approved by the corporation, which includes the generation business unit.

Q. - So for your purposes it's an integrated utility but for the purposes of filing the numbers NB Power Generation is a separate item and that cost data can't be made available to this Board.

I mean, you are either an integrated utility or you are here as NB Power Transmission, as that transmission unit. I'm having a hard time seeing how you can have it both ways.

MR. MARSHALL: We are here before the Board for a tariff that is a tariff of services that will be provided by the NB Power transmission business unit. But we are still only one corporate entity. We are here as NB Power Corporation, as the legal person before this Board.

Q. - And they have agreed with the use of these proxy units and these charges and these are the charges that will be flowing through from NB Power Generation as the charges charged by Transmission to its customers for this service?

MR. MARSHALL: That's correct.

Q. - Why is there no representation from NB Power Generation here or are you here on behalf of Generation and Transmission?

MR. MARSHALL: We are here on behalf of Transmission for the tariff and the application for this Board.

Q. - I guess I'm having a difficulty with the distinction. But we will move on, Mr. Chairman.

Now we were talking about the release of information. If you were to use an embedded cost method for deriving this rate schedule you would not have to reveal the price of energy like your -- NB Power Generation's fuel costs wouldn't be released, but only the embedded cost of the facilities, correct, or information around the embedded cost of the facility?

MR. PORTER: That's correct.

Q. - And with respect to your comments on embedded cost pricing in response to Saint John Energy IR 66 that I had referred to previously, rate schedule 2 is not an ancillary service that can be procured on a competitive basis by load, is it?

MR. PORTER: That's correct.

Q. - It is a mandatory service from the transmission company or the ISO if they are -- if one occurs?

MR. PORTER: That's correct. And that's as per the FERC pro forma.

Q. - And the transmission company or the ISO is going to pass the cost from the generators through to the customers?

MR. PORTER: The cost, yes, that's correct.

MR. MARSHALL: No, it's the other way around. The other way around. The transmission provider is going to collect the rates from customers and pass the revenue back to NB Power Generation.

Q. - Thank you, Mr. Marshall, that's fine. Now if we can turn to page 50 of the transmission tariff document.

CHAIRMAN: Mr. MacDougall, just looking at the time and you are going to need probably 20 minutes on your break time, are you not? There are a number of things you were going to do is what I'm saying.

MR. MACDOUGALL: Yes. That's probably true, Mr. Chair.

CHAIRMAN: Well we will take a 15 or 20 minute break.

MR. MACDOUGALL: 15 minutes will be fine for us, Mr. Chair. Thank you.

(Recess)

CHAIRMAN: Mr. MacDougall, did you want to mark something as an exhibit now?

MR. MACDOUGALL: I didn't, Mr. Chair. I had one reference from Mr. Porter. We can -- I can just indicate what the reference is or he can -- he did --

CHAIRMAN: No, I'm sorry. You referred to a document earlier on in your cross.

MR. MACDOUGALL: I did, Mr. Chair. That's the operations and maintenance expense account document.

CHAIRMAN: Yes.

MR. MACDOUGALL: I could not get that copied at the break and over here. But I will get it to you at the luncheon break.

CHAIRMAN: All right. Carry on, sir.

MR. MACDOUGALL: I couldn't get it all back and over. But there was the other reference as well which Mr. Porter has and Mr. Porter you can go ahead.

MR. PORTER: Yes. Just the question was where in the Rudden report was it indicated that in Maine the noncoincident peak billing demands were used? And so it's in the Rudden report on page 6, lines 4 through to 11. And it says, However, many jurisdictions in the U.S. the FERC permitted the cost responsibility and billing of transmission service to be done on the basis of determinants other than coincident peak demand.

For instance, transmission service in New York under the New York independent system operator open access transmission tariff is done on a per megawatt hour basis.

In areas that have implemented retail access such as in Maine, FERC has permitted the billing of transmission service to retail customers taking unbundled transmission service on the basis of determinants used for the bundling -- for the billing of bundled retail rates.

And go on a little bit further and say, NB Power's proposal is therefore not inconsistent with variations permitted in the U.S. and will result in a simplified and efficient way of implementing retail choice in New Brunswick, eliminating the need to invest in new metering equipment where such interval metering is currently not installed.

Q. - Thank you, Mr. Porter. My only question arising from this, this is in the Rudden report, so do you have any knowledge, this panel that -- can speak specifically to what the arrangements are in Maine and how those operate and how those operate and how they were determined? The reference in here.

MR. PORTER: I do recall a conversation with Mr. Garwood about some of the work that was done to determine the coincidence factor that would be used. That that was a fairly lengthy process and very involved. Other than that I have no further detailed knowledge.

Q. - Thank you. If we could now turn then -- again we are in the transmission tariff document, so appendix B to Mr. Porter's evidence at page 50.

At line 13 it is stated that the proxy selected for this service is a set of three 110 MVAR synchronous condensers. A synchronous condenser most closely simulates the reactive supply and voltage control services provided by a synchronous generator. The ability to operate at either a leading or lagging power factor and the inertia that a synchronous condenser has makes it a reasonable proxy from the point of view of technical capabilities.

Now if we turn to page 73 of the same document. This is schedule 2.1 on page 73. We can see about approximately three lines down there is a line that states, Adjustment to account for the fact that a synchronous generator is more economical because of the dual purposes served by the generator, energy production and reactive supply and voltage control.

And accordingly you have put in a 50 percent factor to accommodate, we understand, for the fact that a synchronous generator would also produce energy, correct?

MR. PORTER: That's correct.

Q. - Now so that we are clear here a synchronous condenser would only produce VARs, correct?

MR. PORTER: Correct.

Q. - Or a synchronous generator in that mode will only produce VARs?

MR. PORTER: That's correct.

Q. - And since you were using it as a proxy to simulate the reactive supply and voltage control services provided by a synchronous generator, you used a 50 percent factor since a synchronous generator also produces energy?

MR. PORTER: That is correct.

Q. - Why have you used 50 percent?

MR. PORTER: The 50 percent is simply based on the fact that it is one investment which are providing two services. We had no specific sophisticated calculation to come with any other allocation factor. That's what we deemed to be an appropriate factor, again based on the fact there are two services provided by the same asset.

Q. - So you don't have any supporting documentation to support the 50 percent figure?

MR. PORTER: No. Other than the fact that there are two services which gives you a 50 percent factor.

Q. - Okay.

MR. PORTER: And that's not uncommon in regulatory processes. I can cite examples, not for this particular service but in other jurisdictions where a 50/50 allocation has been performed.

Certainly in BC Hydro with their capacity based ancillary services, they have looked at the revenue requirement associated with generation capacity and recognized that there are contributions to those fixed costs from both ancillaries and the production of energy and have taken a 50/50 allocation.

Another area not as closely related but is in Alberta where they have taken the transmission costs and chosen to allocate them 50/50 between loads and generation. I don't believe that there is any detailed calculation as to where the 50/50 comes from. I believe it's a split between two functions or two services.

Q. - Well would you agree that it's more likely that a generator would be producing kilowatts in the range of 80 to 85 percent of the time and VARs in the range of 15 to 20 percent of the time, rather than 50/50?

MR. PORTER: No, I wouldn't agree with that. In terms of the provision of reactive supply and voltage control, the synchronous generator, when it is on line and it is automatic voltage regulator is functioning, is providing that service 100 percent of the time. They are provided simultaneously.

Q. - Yes. But when we are talking about the capacity of the machine here, and you are saying what it can do 50/50, wouldn't the capacity of a generator, when it was going to be used, be producing kilowatt hours the majority of the time rather than VARs?

When you are using it for VARs only then it is only going be used for VARs. But what you are doing is imposing a factor here, saying why a synchronous condenser should have a 50 percent factor on a synchronous generator?

MR. PORTER: No. I'm really talking about the fact that on a simultaneous basis the synchronous generator would be providing two services, reactive supply and voltage control and producing energy.

And the part of the generating plant or generating unit that is really giving those two -- providing those two services and getting value to the system is the generator itself.

And so we have given half of the credit to the production of reactive supply and voltage control and the other half to the production of energy.

Q. - So in determining an allocation factor here, you have no reason to expect that only 50 percent -- no reason to expect that 50 percent of the embedded cost of generation should be attributable to the production of energy or a higher portion?

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

Q. - Probably not in that way. But I will try and do it another way. I guess what I'm getting at, Mr. Porter, is that what we are trying to do here is attribute costs, correct?

MR. PORTER: Correct.

Q. - And what I'm suggesting is that 50 percent of the total capital costs of a synchronous generator aren't for the production of VARs. The majority of the capital costs should be attributed to the production of energy for a synchronous generator.

And I would like to know why you think you can attribute 50 percent of the capital cost of a synchronous generator to the production of VARs?

VARs, I think I said jars there.

CHAIRMAN: I can't define the bars that I'm familiar with. But it might be helpful for this Commissioner if you were to tell me what a VAR is.

MR. MACDOUGALL: I'm going to defer to Mr. Marshall for sure.

CHAIRMAN: Do you want me to retract that, Mr. Marshall?

MR. MACDOUGALL: I can tell you an MVAR is a thousand bars. But I'm not sure if I can tell you what a VAR is.

MR. MARSHALL: Actually it is a million.

MR. MACDOUGALL: A million VARs, sorry.

CHAIRMAN: All right. I guess I don't want to know.

MR. MARSHALL: Power -- electrical power is a complex mathematical quantity. So the kilowatts are the real component. The kilovars are the component of the power that are 90 degrees out of phase with the real component.

So it is an imaginary number mathematically. But it is the total power output in complex terms is the product of the voltage and the current.

And the voltage and the current are not always in phase with each other. If they are in phase the product is real power. If they are out of phase the product is total volt ampere output.

Some of it is real power. And some of it is imaginary power which is measured as VARs. This is the volt ampere reactive component which is the imaginary component of power.

CHAIRMAN: Can you relate the imaginary power to what we have been talking about here?

MR. MARSHALL: The reason is mathematically it is an imaginary component.

CHAIRMAN: Who pays for the VARs which is imaginary power?

MR. MARSHALL: Who pays for the VARs? The reason it is a cost issue is that loads in the system are lagging and that the current is not in phase with the voltage.

So generators have to produce power in the opposite size, have to produce VARs to offset the VARs taken by the load. That means they have to produce more current output.

And the current has to be out of phase with the voltage in order to match up and keep the system matched. That costs the generators more money to do that. And they have to have the equipment in place to operate there to do it.

CHAIRMAN: So compare a synchronous generator with a nonsynchronous generator. What is the difference between those two?

MR. MARSHALL: If it is a nonsynchronous generator -- there are different types of generators. We could have DC generators or we could have an induction type of a generator. An induction generator does not produce VARs. It actually operates more as a load and consumes VARs.

Synchronous generators have the ability to inject field current in and change the operating angle between the voltage and the current that it produces, so that it will provide the VARs necessary that are consumed by loads on the system.

Now if you need any more detail, I'm sure Dr. Sollows could help you out.

CHAIRMAN: I don't want to be exposed to that. Thank you, Mr. Marshall. Go ahead, Mr. MacDougall.

MR. SOLLOWS: Can I ask one question?

CHAIRMAN: Well, go ahead.

MR. SOLLOWS: The question that is running through my mind as I'm listening to this exchange is power factors. Maybe it would be a good time to explain what power factor is.

And I'm wondering if there is any history in terms of power factors that would help inform this 50/50 split?

MR. PORTER: I do want to address the question of the 50/50 split. But I have been thinking about it here, and I think the confusion lies from -- it is not intended to say that you take the generator cost and attribute 50 percent of it to the provision of this service and 50 percent to energy.

You have to look at what is taking place here, is that the proxy is a synchronous condenser which provides the one service only.

And if we use that to calculate what the revenue requirement is for the generator, it would overstate that revenue requirement. Because the cost of getting that service from a pure -- a synchronous condenser would be higher.

You have got a similar amount of copper and steel invested but only getting one service. So we didn't want to overstate the value of that service. So we said really only half of the cost on a per kilovar basis should be attributed to the provision of that service.

Because we know that the generator has the capability to provide both. But it does not mean that you would take the total generator cost and divide it by half and get half of the cost covered by this service.

I hope that helps.

MR. SOLLOWS: It is clear what you are doing.

Q. - I'm sorry, Mr. Porter, if I said -- you know -- that you are only taking 50 percent of the total fixed costs of the synchronous condenser, not of the generator?

MR. PORTER: Correct.

Q. - And that's right. But I was trying to determine on what basis you could make that allocation, where it's being a proxy for a generator?

MR. PORTER: I thought I heard --

Q. - I think we have got as much of an answer as we can.

Would the capital cost of a synchronous condenser generally be lower than the capital cost of a synchronous generator?

MR. PORTER: I'm sorry. I would have to have more information about the size and capabilities.

Q. - I guess all other things being equal?

MR. PORTER: What we are saying is that to get the same -- for the generator, the generating unit itself that we are talking about versus the synchronous condenser they would be roughly the same.

MR. MARSHALL: Just to clarify that. For the rotating equipment piece of a generator they would be the same as the rotating equipment of a synchronous condenser.

All the ancillary equipment associated with the production of power to drive a turbine and the turbine associated with the generator are additional equipment only allocated to a generator.

Q. - I guess what I am getting at -- maybe I will jump through a few questions here. What I am trying to get here -- get at here is you are coming up with a 50 percent allocation factor. So you are just allocating that. And you are using a proxy of a condenser or a synchronous generator again as a proxy unit.

And my question would be wouldn't the use of embedded cost pricing overcome the need to use a proxy unit and the need to make any determination with respect to arbitrary adjustments to a proxy unit?

If you didn't have a proxy unit, if you were using embedded costs, we wouldn't have to have any debate about what these allocations were or weren't. Or what the cost of a synchronous condenser, which isn't being used, is or isn't.

MR. PORTER: That is correct.

Q. - In fact then, the proxy unit approach, in my words, the arbitrary use of a 50 percent figure -- I know you don't take it that way -- really allow you to avoid some effort and provides a fairly easy method to look at the cost of this service rather than determining the embedded cost of this service?

MR. PORTER: I don't -- it's a reasonable method and I don't know that it is necessarily any easier. And I would also point out that even under the embedded cost approach you would be looking at -- you would be looking at real costs. But there is still a requirement to do an allocation of those costs between the two services.

So at some point you may choose 50/50, you may choose some other rationale, but at some point you have got to take one investment and allocate its costs out to the provision of two services. That problem still exists.

Q. - But that allocation would be based on the cost of the service?

MR. PORTER: But the allocation process is still there. Some allocation factor would need to be established, some judgment would need to be made as to what the appropriate allocation factor would be. And yes, you would be applying it to real costs, in this case you are applying it to the cost of a proxy unit. But in terms of selecting the allocation factor, the issue still exists.

Q. - Thank you, Mr. Porter. I am now going to turn to another rate schedule. We don't have to pull the schedule up, but the questions now are on rate schedule 4.

You will be pleased to know, Mr. Chair, we aren't going through each rate schedule.

Gentlemen, if you have the transcript there, I would like you to turn to page 282, which is the transcript for November 19th.

So at page 282, I would just like to go -- these were questions by Mr. Belcher from the Northern Maine ISA. The bottom question was "In your response you say if Northern Maine chose network service, I assume though then any entity outside of the province will be able to purchase network service." Mr. Snowdon's answer was "Yes, as long as they are within the Maritime control area."

So can you just confirm that today?

MR. PORTER: Yes, that's correct.

Q. - So can I give you a hypothetical --

MR. MARSHALL: Subject to, I believe in this response and further cross examination, Mr. Scott clarified that, and Mr. Snowdon, that for entities outside the control area, there would need to be an operator to operator agreement interaction that the data associated with those loads would be brought forward and be able to be administered.

But subject to that, yes.

Q. - That's right. And that was with respect to some of the questions on Houlton Water, et cetera. Thank you, Mr. Marshall.

MR. MARSHALL: But not outside the control area. Inside the Maritime control area.

Q. - So let me take a hypothetical then and see if it changes anything. If I am marketer and I am going to purchase network service from NB Power Transmission, can I deliver generation from NB Power to load in Northern Maine and generation from Northern Maine to MEPCO for load in New England on network service?

MR. MARSHALL: No. The MEPCO interface is an interface between control areas from the Maritime control area to the ISO New England control area. And the tariff, I think there is actually a provision in the tariff that the restriction on network service has to be loads within the control area. And it is standard FERC pro forma requirement.

Q. - So the transmission of generation from Northern Maine to MEPCO, because MEPCO is not in the Maritime control area, wouldn't be able to avail itself of network service but would have to use point-to-point service?

MR. MARSHALL: Yes, that is our understanding. At any interface to an external control area, be it with Hydro Quebec or with MEPCO interface into Maine, those are the two interfaces to external control areas, service across those interfaces would have to be point-to-point service.

Q. - Okay. With respect to customers with network service and load external to New Brunswick but in the Maritime control area, is the billing determinant for network service going to be based on coincident or noncoincident peak?

MR. MARSHALL: I believe Mr. Scott responded to that as well earlier, that the service would be on a noncoincident peak basis.

Certainly the issue of ancillary services is one where ancillary services are allocated on a coincident peak basis to the areas, to Northern Maine, to Prince Edward Island, to New Brunswick, Nova Scotia. And that then the billing -- once the allocation is made, that allocation is then divided by noncoincident peak load in order to get the rate.

So that in order to treat all customers fairly inside Northern Maine and inside New Brunswick, it should be done on an equivalent basis. So that it would require it to be on a noncoincident load inside the Northern Maine area or inside Maritime Electric and PEI.

Q. - Thank you, Mr. Marshall.

MR. PORTER: I might for the record just add the reference in the tariff document itself is Section 28.1, scope of service. And I will just read it out, that it indicates that network integration transmission service is a transmission service that allows network customers to efficiently and economically utilize their network resources, to serve their network load located in the transmission provider's control area.

Q. - Thank you, Mr. Porter. If we could pull up, and I think it would be useful just to have the two documents in front of us now. So the tariff design document, page 54, and then the actual tariff, schedule 4, which is pages 89 to 92 of the tariff document, of the actual tariff.

And my first questions are really just for clarity here. Schedule 4 deals with energy imbalance service. And it's then broken up into energy imbalance of service associated with point-to-point and energy imbalance associated with network service. And network service is dealt with on page 91. So if we can turn to page 91. And at the same time have page 54 with the chart in front of us.

So we understand that there is essentially two deviation bands available for network service with respect to energy imbalance. The first is the plus or minus 1.5 percent with a minimum of 2 megawatts, which is the same standard deviation band for point-to-point service. And then what is called at line 19 of page 91, a second deviation band called network service band of plus or minus 10 percent. And then it goes on to say outside of these bands it will be subject to certain charges, correct?

MR. PORTER: That's correct.

Q. - So in the tariff document it appears that both deviation band 1 and 2 are subject to the charges as set out at the two bullets at line 21 and 25?

MR. PORTER: That's not the intention. Within the inner deviation band can be returned in kind and that is as described -- I believe it is on the previous page, page 90.

Q. - No, I don't think -- we are probably just not on the same wavelength here, Mr. Porter. With respect to those two deviation bands, if you are outside of the deviation band, okay, this sets out charges that the customer will be subject to, correct?

MR. PORTER: That's correct.

Q. - Yet when you go to page 54 you have got blocks here and it appears that outside of the block that you could return in kind for network service only there is a customer pays at the market rate, and then once you are outside of the plus or minus 10 percent, then the charge comes into play.

And I guess I would just like to know what is the price that the customer pays, that the network service customer pays in the middle blocks here? Customer pays at market rate network service only. Is there any penalty for them being outside of the plus or minus 1.5 percent and 2 megawatts, between that and the 10? And I'm just unclear on it, so --

MR. PORTER: I want to refer you to page 92. That's as described, energy imbalance which is outside of the inner deviation band which is prescribed by FERC and -- but within the network service band, which is the plus or minus 10 percent, that imbalance will be subject to the charges identified on page 92. And that that is -- it's our attempt to establish essentially market based pricing on those energy imbalances.

Q. - And can you explain to us why there is a different -- and let's call it a imbalance charge rather than a penalty charge, but a different imbalance charge for that block than for a point-to-point customer who is outside of the 1.5 or a network customer that's outside of the larger band of 10?

MR. PORTER: Certainly. Firstly I would like to point out that it is -- whether or not a customer is a network customer or a point-to-point customer is largely at the discretion of the customer as Mr. Marshall pointed out in his presentation as we just discussed a few moments ago. So the customer chooses the service.

And general network service is designed intended by FERC to be available for a certain type of load which wants to be billed for transmission based on what their usage is and not be in the business of trying to reserve the transmission that they require and it's really designed for a different type of load customer than is the point-to-point.

The point-to-point is intended to be available for a customer that would benefit from being able to reserve specific quantities over specific paths.

And our belief in general is that a typical network customer would have some difficulty in staying -- adhering to the inner deviation band. So there would tend to be some deviation from schedule. And in response to the market design committee recommendations, we wanted to attempt to make that market based, so we established this plus or minus 10 percent deviation band, and priced energy imbalance within that band at market based prices.

It was not our understanding that the point-to-point customers would be in need of that larger bandwidth because that service is typically taken by a load that says I need 100 megawatts delivered from point A to point B and that's what they take. And there is -- they may have other energy products stacked on top of the block of energy that they are buying, but effectively they can reserve, schedule and take the quantity identified.

That's why there is a difference between the two services in terms of the deviation bands.

Q. - Mr. Porter, just come back to your first comment just so that we are clear and we can tie back to my first questions. You said that Mr. Marshall had said this was optional to a customer to pick network service or point-to-point service. But you also mentioned -- when I asked my hypothetical of whether or not a customer with generation in northern Maine who wanted to serve load in MEPCO could use network service and you said no, because

MEPCO isn't within the Maritime control area. Correct?

MR. MARSHALL: That's correct. And that would apply to generation in New Brunswick or PEI or Nova Scotia as well. Any generation in the control area. The MEPCO interface -- to use the MEPCO interface requires point-to-point service.

Q. - Yes. So not all customers generating in New Brunswick and transferring load out of New Brunswick have this option, only those who are providing it within the control area, serving customers in the control area?

MR. MARSHALL: It's a function of where the load is.

Q. - Yes. Why if network service can be paid at market rate, why couldn't it be returned in kind then?

MR. PORTER: If it's returned in kind you can certainly fall into the situation where the value at which the energy is taken from the system is different from the value at which it is paid back by the transmission customer. And therefore cost shifting would result.

MR. MARSHALL: The wider the bandwidth is to allow returning energy in kind provides an opportunity for gaming of parties using the system and leaning on the generators that are providing the AGC and load following. Those generators would automatically change and pick up and provide the energy required to deliver the imbalance. And because the time value of that energy as Mr. Porter said could be very different from when it's given back, that to avoid that type of gaming and exploitation of the party delivering that energy, you need to have a narrow bandwidth on energy imbalance.

Q. - Now with respect to the network service, and I think we might have asked this earlier, for the foreseeable future who is going to be the largest purchaser of network service in New Brunswick?

MR. MARSHALL: Mr. Porter said NB Power Distribution Customer Service.

Q. - So NB Power Distribution Customer Service will be the party who is most able to avail themselves of the plus or minus 10 percent bandwidth, as the customer most likely to take that service?

MR. MARSHALL: As the largest load, but any network customer, Saint John Energy, any of the municipals, any of the large industrial customers who have access in the market for competitive choice. And they could be aggregated together. So it could be WPS that supplies a number of these customers and they could aggregate them all together and they would take advantage of that network service as well as anybody else.

Q. - Thank you. And I just have a few questions on rate schedule 5. Again we don't have to go to that rate schedule yet, maybe we could just keep it in front of us. And that's the final series of questions that we have.

So if we could go to page 68 of the transmission tariff design document. And you are showing supplemental 30-minute operating reserves at a rate of 5661, rate for ancillary service, page 68 of the tariff design document, schedule 1.1?

MR. PORTER: That's correct. Just to clarify what that number -- that is the 30-minute component of the supplemental reserve.

Q. - Yes.

MR. PORTER: And that is the revenue requirement for Generation. So that is not necessarily what the Transmission customer would pay as a function of their load.

It is what would be -- it represents the dollars that would flow to Generation for each kilowatt of capacity, providing the service.

Q. - But that is the rate you are putting forward for that ancillary service?

MR. PORTER: No.

Q. - Well, it says "rate for ancillary service 5661."

MR. MARSHALL: That is the cost. That is the proxy cost of that capacity. And the rate is determined -- as explained the other day, you need to take that proxy cost 5661, multiply it by the requirement for megawatts or kilowatts for 30-minute reserve and then divide it -- take that total in the numerator and divide it by the 2571 billing determinant and get a rate that is charged to customers.

Q. - Okay. But it is driven off of the cost that you are going to acquire it from Generation of 5661, is that correct?

MR. MARSHALL: That's correct.

Q. - Okay. And could you tell me what your current rate is for that service, under NB Power's current tariff?

MR. MARSHALL: The current tariff does not have a rate for -- it has a rate only for voltage support and for system control and dispatch. There are no rates in the current tariff. The current tariff is only an out and through tariff.

So it is strictly a point-to-point tariff only across and out of the system and does not have provision in it for all of the reliability related ancillary services which are usually associated with network service.

MR. MACDOUGALL: If I could just have one second, Mr. Chair.

Q. - Now on the same document under the "capital cost" column, column 2, can you tell us how you derive the capital cost numbers in that column for each of combined cycle greenfield unit, combustion turbine simple cycle and a combustion turbine simple cycle quick start unit?

MR. PORTER: Yes, I can. I think it would be -- if we could turn up a response to an Interrogatory. So it would be A-4, an Interrogatory from Nova Scotia Power. That is number 29.

CHAIRMAN: 246?

MR. MARSHALL: 247 and 248 are the tables we would refer to. So the cost data used as the basis for the proxy costing is the same data that was done in the integrated resource planning studies of NB Power before this Board in the Coleson Cove and Point Lepreau hearings.

So that these tables, table 3.1 and 3.3 I believe are from the Coleson Cove evidence in the Coleson Cove hearing. And that is the basis of the data.

And then they would have been moved in time. These are all 2006. They would have been adjusted to 2004 as the basis, the starting point for the proxy calculations.

Q. - And Mr. Marshall, NB Power has units today that provide these operating reserves, correct, on your system?

MR. MARSHALL: Yes.

Q. - Thank you. And more for information than anything, Mr. Marshall, or whoever is most able to answer, column 8 of the same schedule, schedule 1.1, could you tell us what that number, the 121 refers to, the contribution reactive supply?

MR. PORTER: Yes. That is -- that number is in recognition of the anticipated revenues to the owner of the generator for the provision of reactive supply and voltage control, schedule 2, ancillary service in the tariff.

Q. - And when you say the anticipated values, what is the basis for that figure? How is it derived?

MR. PORTER: Firstly it has been pointed out to me that we have responded to that in that same Interrogatory. I'm going to summarize it.

And the calculation is based on -- the figure here, the 48.4 percent which is on this schedule, on this page 68 -- on the tariff design document --

Q. - Page 68?

MR. PORTER: -- page 68.

Q. - And there is no real question here. I'm just trying to determine --

MR. PORTER: Okay. I'm just going to go through it very slowly here to make sure that we get it straight. That number describes the relationship between the megawatt capability of the generator versus its megavar capability.

So given that the supplemental reserves are provided off of 100 -- let me pick the regulation. The 400 megawatt unit, the calculation was performed to determine the megavar capability of that unit.

And then if you were to turn to another schedule, schedule 2.1 at page 73, you would take the megavar capability of the unit, multiply it by $5.25 per kilovar year which is the revenue requirement.

And then one other adjustment is based on the fact that the capability in the system for VAR output exceeds what we have estimated to be the peak requirement.

So the adjustment factor to account for that is note 5 on that same page. It is 47.5 percent.

Q. - I think --

MR. PORTER: And to go beyond that -- that follows the logic. But beyond that I would certainly offer, if it is deemed appropriate, to put that out in a piece of paper for submission.

Q. - Mr. Howard would appreciate that.

MR. MARSHALL: Dr. Sollows too.

MR. MACDOUGALL: Slightly less confusing than what a VAR is, Mr. Chair.

Panel, that is all my questions. Mr. Chair, I would really once again like to thank the Board and all the participants here for their indulgence. And Mr. Howard particularly would like to thank you in that regard. It is much appreciated.

And I will have that one document ready at lunchtime. Again I apologize for not having had it in advance.

CHAIRMAN: No problem. Thank you, Mr. MacDougall.

Mr. Nettleton, do you want to start, or would you rather break now and come back about quarter after 1:00?

MR. NETTLETON: I'm at your pleasure here. I can start if you would like. I don't think my first area will last only 15 minutes. I think I will be going longer than that. So whatever you would like.

CHAIRMAN: All right. Then if you wouldn't mind proceeding, why we will go ahead.

CROSS EXAMINATION BY MR. NETTLETON:

Q. - Good morning, panel. My first area of questions will likely be directed to you, Mr. Lavigne. They concern your evidence at page 4, lines 15 and 16. And they deal with pension costs and liabilities. Perhaps you could turn that up.

Have you got that, Mr. Lavigne?

MR. LAVIGNE: Yes, I do.

Q. - All right. And from that am I correct that the asset base includes a proportionate share of NB Power's consolidated deferred pension costs and liabilities?

Do you see that?

MR. LAVIGNE: Yes, that is correct.

Q. - And is it correct then that the deferred pension costs and liabilities as well as retirement costs are allocated to the Transmission business unit simply based on the fraction of employees the business unit has out of all of NBP's employees?

MR. LAVIGNE: Yes, that is correct. That is the approach we undertook.

Q. - Does this mean that on an average a Transmission employee gets the same pension benefit and dollar value as New Brunswick Power employees in other divisions?

MR. LAVIGNE: I couldn't say for sure.

Q. - Have you done any study that shows that this is an appropriate method of allocation?

MR. LAVIGNE: I believe it was part of the cost allocation study, the Deloitte & Touche study, OM&A -- allocation of OM&A expenses, corporate OM&A.

Q. - Could you turn to that document? I believe that was exhibit A-3. Sorry, A-6. A-5. I'm sorry for the confusion. I will get it right yet.

Do you have that, Mr. Lavigne?

MR. LAVIGNE: Yes, I have the document.

Q. - Now as I understand it, this document reports on the allocation of overhead to capital projects and corporate OM&A costs to business units, is that right?

MR. LAVIGNE: Yes, that is correct.

Q. - And you are indicating that there is -- the allocation methodology is part of this study for pension costs?

MR. LAVIGNE: Yes. In appendix J which I believe is the last spreadsheet of that particular document, there is a corporate cost of pension and vacation accrual. The activity driver was the number of employees.

Q. - I'm sorry. I see on appendix J -- I'm looking for a column that indicates pension. Are you saying that that is -- oh, part of corporate cost --

MR. LAVIGNE: Yes.

Q. - -- pension and vacation accrual?

MR. LAVIGNE: It starts corporate cost, yes. That is the correct one.

Q. - So do I take it then that this is the total corporation's pension costs that are being allocated?

MR. LAVIGNE: Yes, that is the case.

Q. - Could we then go to the Province of New Brunswick Information Request 28, part 6?

CHAIRMAN: A-4?

MR. NETTLETON: A-4.

CHAIRMAN: Page?

MR. NETTLETON: It is page 314.

CHAIRMAN: Thank you.

MR. LAVIGNE: Yes, I have it.

Q. - Now can you confirm with me, sir, that the deferred pension benefits have increased as shown here from 53,277,643 to 100,106,572? Do you see that?

MR. LAVIGNE: Yes, I do.

Q. - And subject to check, would you agree that that is an 88 percent increase?

MR. LAVIGNE: I will have to take your word for it on that, subject to check.

Q. - Thank you. And from this chart, Mr. Lavigne, can you also confirm that the number of employees for Transmission have increased only from 279' to 302'?

MR. LAVIGNE: Yes, that is correct.

Q. - Well, I guess what I'm interested in then, sir, is why have the deferred pension benefits increased so fast when the number of employees has remained relatively constant?

MS. MACFARLANE: These calculations were prepared in conjunction with NB Power's actuaries. They are extrapolations off the latest actuarial review which indicated that the pension plan was in surplus. So you see that the assets are growing by a larger amount than the liability.

As you pointed out, the number of employees is not growing very significantly. The average salary per employee is not growing very significantly. And yet there is an earnings assumption on the assets that the actuary has applied, which compounds itself over that period of time leading to a growth in the asset.

Now I might indicate that since the time we prepared this the Province has undertaken through their actuaries another actuarial review which would indicate the plan is now in deficit.

So as opposed to the large credit that we would see being attributed to OM&A corporate, in fact there may well be a cost in the test period. But we have chosen not to make that change.

Q. - All right. So do I take it then the Deloitte & Touche study on this topic is then out of date?

MS. MACFARLANE: The Deloitte & Touche topic -- study was dated August 2001. I think the testimony indicates that the numbers were updated for the following fiscal year.

But since the time of the completion of the fiscal year and since the time of the filing of the evidence, you probably are as aware as anybody that the markets have not been performing all that well.

The Province accordingly has asked their actuaries for a more updated view of the assets and liabilities of the plan.

And the plan is no longer in the surplus position that it was. That would suggest that there is going to be a pension expense in future as opposed to a large pension credit.

So our costs for revenue requirement are understated for the test period. But we chose not to make that adjustment.

Q. - Ms. MacFarlane, does your accounting system track individual employees based on their business unit employment?

MS. MACFARLANE: The human resource system would track number of employees by unit, yes, or the employees by unit.

Q. - And so your system would then be able to track the individual pension contributions made by individual employees within the Transmission business unit, is that fair?

MS. MACFARLANE: It is the pension plan administrator that tracks those costs and liabilities, not -- and the pension plan administrator is the Province of New Brunswick.

Prior to the announcement of restructuring those assets, liabilities and costs had not been distributed by unit. So we had made an approximation based on the number of employees.

I understand that the Province, the actuaries and our human resource division is currently determining what the allocation of the pension assets and liabilities by division will be, so that when the companies are incorporated they can ensure that the costs, et cetera are attributed appropriately.

Q. - Well, when that proper attribution is made, is it then your intention to have the numbers that you have included in the rate base calculation adjusted accordingly?

MS. MACFARLANE: I believe it will again be part of a safety mechanism in the PBR. I think the number of employees is -- the employee profile across NB Power is reasonably consistent.

By nature of the business that we are in, we have a large number of highly technical people employed. And the attribution of number of employees, we believe and our actuaries believe, and obviously Deloitte & Touche believed, is not unreasonable.

Q. - But the Deloitte & Touche report was prepared by, as you say, sometime before this proceeding, correct?

MS. MACFARLANE: That's correct.

Q. - And your evidence here today is that steps are under way by your pension fund administrator to perform another allocation based on business units, right?

MS. MACFARLANE: That's correct.

Q. - Why would we not use that allocation method as part of the starting point revenue requirement?

MS. MACFARLANE: If it is significantly different from what we see here, it will show up in the PBR mechanism.

Q. - I don't dispute that. My concern though is if it does show up in the PBR mechanism, who takes any savings associated with that or differences in costs associated with that?

MS. MACFARLANE: The PBR mechanism would say that if our returns differ, vary between 10 and 12 percent, there is no sharing. Above 12 percent there is 50/50 sharing. And below 10 percent there is 50/50 sharing.

Q. - Will the pension fund administrator have conducted the completion of its allocation prior to the market opening?

MS. MACFARLANE: It is important that they complete it prior to the butterflies, shall we say, being incorporated, so that the appropriate assets and liabilities can be transferred from NB Power to these new entities.

Q. - Are you prepared to have that allocation made by your pension fund administrator submitted to this Board?

MS. MACFARLANE: Yes. We can consider it a Z factor I suppose, if you would like us to do that?

Q. - A Z factor? I'm not --

MS. MACFARLANE: Yes.

Q. - -- asking you to consider it as a Z factor. I'm just simply wanting to understand whether that information would be something that you would be prepared to file with this Board. Is it?

MS. MACFARLANE: To the extent that there is personal information that the corporation is restricted from releasing because of the personal information legislation in the province of New Brunswick, we would not be able to disclose it.

But in totals, numbers of employees, assets associated with the pension assets of those employees, liabilities, et cetera, we certainly could provide that, yes.

MR. NETTLETON: Mr. Chairman, I am going to now move on to a different area. It is noon. I'm quite happy to take a break for lunch now if you so wish.

CHAIRMAN: All right. We will break for lunch and come back at 1:30 then.

(Recess - 12:00 p.m. - 1:30 p.m.)

CHAIRMAN: Any preliminary before we start this afternoon?

MR. MACDOUGALL: Yes, Mr. Chair. Dave MacDougall for WPS. I had the one document that we mentioned earlier this morning. I have given seven copies to Ms. Legere. I left a copy for each of counsel for the applicant and left a dozen or so copies at the back of the room. And if we could have an exhibit number. I think the document can be entitled FERC Operation and Maintenance Expense Account.

CHAIRMAN: Well that is WPS-1.

MR. MACDOUGALL: And it is the last of the WPS's too, so it's one and only.

CHAIRMAN: One of one.

MR. MACDOUGALL Thank you, Mr. Chair.

CHAIRMAN: Thank you, Mr. MacDougall. Go ahead, Mr. Nettleton.

Q. - Thank you, Mr. Chairman. Now on to that great topic of amortization. Mr. Lavigne, we will be discussing your evidence and in particular line 1 of table 1. And will you confirm with me, sir, that the amortization you are seeking this Board to approve as part of the revenue requirement is $18.4 million?

MR. LAVIGNE: Yes, that's correct.

Q. - And that has not been adjusted, has it, in respect of your earlier corrections with respect to work in progress? That doesn't -- that number is not affected, is it?

MR. LAVIGNE: No, that is correct. There is no effect on that number.

Q. - So it is approximately 19 percent of the revenue requirement then?

MR. LAVIGNE: Yes, that sounds about right.

Q. - Thank you. Mr. Lavigne, when you conducted your review of the appropriate level of amortization, did you take into account previous decisions of this Board respecting that topic?

MR. LAVIGNE: Yes. Our accounting policies which are in place take into consideration any of the decisions that were put forth.

Q. - All right. Through counsel I had asked, Mr. Lavigne, to have you -- or make sure that you had a copy of the New Brunswick Board of Commissioners of Public Utilities decision dated July 16th 1991. Do you have that?

MR. LAVIGNE: Yes, I have it in front of me here.

CHAIRMAN: Ask the Board Secretary to give us that decision. Dated?

MR. NETTLETON: July 16th 1991, sir.

CHAIRMAN: Was that the generic on accounting and financial?

MR. NETTLETON: No, sir. That is in the matter of a generic hearing concerning the depreciation policies of the New Brunswick Electric Power Commission.

CHAIRMAN: Okay. Thank you.

Q. - Mr. Lavigne, I would like you to first turn to page 23 of that decision.

MR. LAVIGNE: Yes, I have it.

Q. - And in the paragraph that starts with "nevertheless", and perhaps it best if I just read that into the record. "Nevertheless it appears logical and sensible to make use of whatever means may be available to estimate service lives. The Board therefore concludes that it is appropriate for NB Power to utilize statistical analysis of historical data to the greatest extent reasonably possible." Do you see that?

MR. LAVIGNE: Yes, I do.

Q. - Can you show me where in your evidence that you have relied upon or have tendered as evidence the statistical analysis which this Board has suggested be used?

MR. LAVIGNE: You would not see it directly in the evidence. But as part of the Province of New Brunswick IR-27, which is in binder A-4 -- sorry, that should be the Province of New Brunswick IR-24. Part 4 of that particular interrogatory --

CHAIRMAN: What page is that?

MR. LAVIGNE: That would be the question is on page 298. The response is on page 303, so I will refer to the response on page 303.

CHAIRMAN: Thank you.

MR. LAVIGNE: Part 1 of that question 3 talks about the depreciation or amortization review committee which reviews the major asset categories on a five year cycle. As part of that process, the historical analysis which you are referring to, takes place.

Q. - I see. So the historical analysis relates to the task carried out by the amortization review committee, is that right?

MR. LAVIGNE: Yes. Part of the process is to designate certain areas to look at on this five year cycle. This -- these -- I guess the various areas would then be delegated out to the engineering and operational people, who would have the best knowledge of these particular components. They would carry out the study which would include the analysis of historical.

Q. - Can I have you turn back to the depreciation study that we were speaking of earlier. And the page I would like you to see or turn to is page 24.

MR. LAVIGNE: Yes, I have it.

Q. - The Board has made a conclusion on page 24 that a full written explanation of the reason for and extent of each adjustment or limitation of service life will be necessary in future depreciation studies. Have you provided that full written explanation in this application, sir?

MR. LAVIGNE: A formal report is developed on a yearly basis which includes all the various studies. This particular report goes to the audit committee of our board of directors. We do not provide any such report to the PUB at this time, to my knowledge.

Q. - But this is a general rate application, is it not, Mr. Lavigne?

MR. LAVIGNE: It is an application for a transmission tariff.

Q. - For approval of what, sir?

MR. LAVIGNE: The approval of a transmission tariff.

Q. - Does it include rates?

MR. LAVIGNE: Yes, it does.

Q. - So this is an application for rates?

MR. LAVIGNE: Yes, it is.

Q. - And you have not included full explanation of service life changes or service life estimates as part of this application, fair?

MR. LAVIGNE: That is correct, we have not.

Q. - Thank you. Mr. Lavigne, you took me to the Province of New Brunswick IR 24, part 4 (i) and you indicated there that the amortization review committee carries out reviews based on individual asset classes, is that fair?

MR. LAVIGNE: Yes. It is kind of the major components such as transmission lines, relay and telecom. Those would be examples of particular areas which would be a focus of an amortization review.

Q. - You will agree, Mr. Lavigne, will you not, that the nature of this application is somewhat unique in that you are intending to have NB Transmission enter into a new regulatory framework?

MR. LAVIGNE: I'm not sure I follow your question.

Q. - Well, this application is unique, is it not, in that you are preparing -- this company is preparing to enter into a brave new world and a new regulatory framework, right?

MR. LAVIGNE: It is our first application for such a -- such a tariff.

Q. - And, sir, the information that you have provided to us in the form of a response to information requested, an attachment which I believe is exhibit A-5. And I don't think you need to turn it up. Is the annual depreciation review committee reports of certain -- of some, but not all of the asset classes that you have included as part of your rate base. Is that fair?

MR. LAVIGNE: Yes. The particular assets which were looked at during those particular time frames, this is the summary report which would have gone to the audit committee.

Q. - So not all of the asset classes are included in that report or in that information. Is that fair?

MR. LAVIGNE: Yes, that is fair. This would only be a cross section of the assets.

Q. - When was the last complete depreciation study undertaken which has analyzed all of the parameters used to calculate depreciation expense for the transmission assets?

MR. LAVIGNE: We revisited our corporate accounting policies which included all of the various components of capitalization and amortization. I believe it was within the last year to two years.

Q. - Has there been a study that has examined all classes of transmission assets in the form of a depreciation study at one time?

MR. LAVIGNE: Not to my knowledge. As I mentioned, we look at the various components on a five year cycle. So, no, we would not have looked at every transmission asset within one comprehensive study.

Q. - What method of depreciation has been used for the transmission business unit since 1996, sir?

z MR. LAVIGNE: We use the straight line method of depreciation for transmission assets.

Q. - Has there been any change in the rates of depreciation for the asset units since 1996?

MR. LAVIGNE: Are you referring to the service lives of the assets?

Q. - No. I'm speaking to the rates of depreciation that you have used for the asset classes since 1996 when the transmission business unit began its operating history?

MR. LAVIGNE: I guess I'm not quite sure what your question is. Because the rates really are a determination -- they are based on the service life of the asset, so --

Q. - All right. Fair. But have the rates changed since 1996?

MR. LAVIGNE: I guess in that context, yes. The service lives for these assets have changed, which would have resulted in I guess changes in the rates.

Q. - Mr. Lavigne, have you compared the historic depreciation rates that you are proposing this Board implicitly to improve compared to those used by other Canadian electric transmission utilities?

MR. LAVIGNE: As part of the amortization review process, that is one of the other components which takes place in this study, is a comparison to other utilities in terms of the service lives of the assets.

Q. - Sorry. Which study are you speaking of, sir? Is it in this evidence?

MR. LAVIGNE: No. It would not be in this evidence.

Q. - Mr. Lavigne, are you familiar with the depreciation concepts or procedures known as average life and equal life and whole life depreciation methods?

MR. LAVIGNE: Yes. I have a fairly good understanding.

Q. - Do you know whether New Brunswick Power has considered or at least analyzed calculating depreciation expense using the methods other than a straight line method of analysis? Have you done that consideration?

MR. LAVIGNE: To my knowledge we have not done so, at least prior to -- or since the decision which you have put forth from July of '91.

Q. - Now are you aware whether other Canadian electric regulatory jurisdictions have typically considered this analysis as part of a formal and detailed depreciation study?

MR. LAVIGNE: No. I'm not aware of such a fact.

Q. - Do you agree that the calculation of annual and accrued depreciation based on the straight line method requires estimation of survivor curves and the selection of group depreciation procedures?

MR. LAVIGNE: I believe that is more in the pooled method and not the straight line method of depreciation. For certain asset bases you would use that particular concept. But I don't think in this case.

Q. - Are you suggesting then that you are not depreciating on a group basis?

MR. LAVIGNE: Within specific transmission lines we would group I guess certain infrastructure. Transmission lines are fairly basic. I mean, you have the poles. You have your conductors.

So I mean, infrastructure within that particular asset can be grouped. But that would be the extent of our grouping within transmission.

Q. - And within each group, have you considered the use of survivor curves to estimate the service lives?

MR. LAVIGNE: Back to the amortization review committee, they would look at the particular service lives for each of those assets.

Q. - So you are not familiar with the method by which the amortization review committee conducts its study or its analysis, are you?

MR. LAVIGNE: Well, they look at various components. Like I mentioned, the historical analysis. They look at the maintenance on the particular infrastructure.

They look at comparisons to other utilities. They look at technological change. All these have an impact on the service life of the asset.

Q. - But you don't know whether they have taken into account the concept of survivor curves to estimate average service life?

MR. LAVIGNE: Not to my knowledge. But I would be willing to take an undertaking to find out that fact.

Q. - That would be great, please. Thank you.

Are you aware whether other Canadian regulatory jurisdictions who rely on this type of analysis for average service life determinations use survivor curves?

MR. LAVIGNE: I'm not aware of that.

Q. - Have you ever heard of the organization called Gannett Flemming?

MR. LAVIGNE: No. I'm not familiar with it.

Q. - You have never seen a Gannett Flemming depreciation study?

MR. LAVIGNE: No. I'm not familiar with it myself. But we -- again going back to the depreciation review committee, we have an accounting policy individual who I guess takes the lead on those particular initiatives.

Q. - Mr. Lavigne, turning to the topic of estimation of net salvage value, does New Brunswick Power employ a practice of adjusting net salvage value calculations by using constant dollar net salvage approach? Do you know?

MR. LAVIGNE: We are not using net salvage value approach.

Q. - Are you aware of whether this practice has been used and adopted in other jurisdictions in Canada?

MR. LAVIGNE: No, I'm not aware of such.

Q. - Turning to the topic of amortization period, sir, have amortization periods for each of the asset classes changed since 1993?

MR. LAVIGNE: Again, the amortization review committee looks at these on a five-year cycle. I would not be able to say whether or not all assets have been looked at.

One would expect if it is on a five-year cycle that all of the assets should have been looked at I guess since 1993.

Q. - So let me understand that. I took from the information request that you provided that indicated -- it is a Province of New Brunswick IR-24, 4.1 -- that there was a five-year cycle implemented for that review of all asset classes?

MR. LAVIGNE: Yes, that is correct.

Q. - Are you now saying that that may not be the case?

MR. LAVIGNE: No. It is the case. It is a five-year cycle.

Q. - But you don't know whether the amortization periods have changed? Or have they?

MR. LAVIGNE: I may have misspoke there. The cycle is in terms of looking at all the assets within that five year cycle. It is not to say that the service lives will necessarily change within that time frame. We do know that obviously certain ones have changed based on the documentation I have provided in the interrogatory which I believe comprised three years. From that we can take that some of the service lives have changed, some of them have remained the same.

Q. - And those are just for a portion of the assets of the rate base, correct?

MR. LAVIGNE: Those would be the portion of the assets which would have been looked at during that timeframe.

Q. - All right. Now Mr. Lavigne, if you could turn to your response to Province of New Brunswick IR-28, part Roman Numeral vi, found at page 317.

MR. LAVIGNE: Could you repeat the reference?

Q. - Yes, it is page 317, your response to Province of New Brunswick information request 28, part vi.

MR. LAVIGNE: That part vi of number 9, would it be?

Q. - I'm sorry. No, it is IR 28, yes, part 9, Roman Numeral vi.

MR. LAVIGNE: Okay, thank you. I do have it now.

Q. - Thank you. I hadn't drilled down far enough. Mr. Lavigne, you indicate in this response, and based on your further correction to the first line distribution system, which I understand to read now, transmission system, that there is a range of years associated with the amortization period for the various assets. Is that fair?

MR. LAVIGNE: Yes, that is correct. There are various components which make up the particular assets in question.

Q. - And those components that make up the period in question is not evidence before this Board, is that fair?

MR. LAVIGNE: Yes, that is correct.

Q. - Now Mr. Lavigne, have these amortization periods been determined by use of engineering studies?

MR. LAVIGNE: Well it goes back to the amortization review committee. Obviously one component is -- would be an engineering study.

Q. - Do you sit on that committee, sir?

MR. LAVIGNE: No, I don't directly sit on that committee. We do have a representative from transmission who sits on that committee and I review the results with that individual.

Q. - Does anyone on this panel sit on that committee?

MR. LAVIGNE: No.

Q. - Thank you. Mr. Lavigne, have the changes to the amortization periods for the transmission assets been reported to the Board when you have made such changes?

MR. LAVIGNE: The results of the amortization reviews would be reported to our own audit committee of the Board, but not to this particular Board, no.

Q. - Not to the Public Utilities Board?

MR. LAVIGNE: That is correct, not to the Public Utilities Board.

Q. - Mr. Lavigne, have you, or do you know whether the amortization review committee takes into consideration the retirement rate method of analysis to analyze actual historic asset life characteristics of a property group?

MR. LAVIGNE: No, I am not aware if they take that into consideration.

Q. - Are the retirement rates that you are using, are they more consistent with the rates used in the past decade or before the last rate hearing? Do you know?

MR. LAVIGNE: Can I get you to repeat that question please?

Q. - Are the retirement rates that you are using in the present application more consistent with the rates used in the past decade or in the time period prior to the last rate case, which I believe was in 1993?

MR. LAVIGNE: I would expect it would be probably more in tune with the last decade. I do know we have had on the transmission line side, you know, a number of life extensions.

Q. - And I think you have provided me the answer, but I will make sure of this. Mr. Lavigne, you are not aware whether New Brunswick Power has used the concept of equal life group -- grouping in your analysis of depreciation or in the amortization review committee's analysis?

MR. LAVIGNE: The only grouping we use currently within transmission is within the transmission line side.

Q. - So the answer is no, you don't use equal life group?

MR. LAVIGNE: Not to my knowledge.

Q. - Thank you. Could I have you turn up information request -- or response to information request 24 to the Province of New Brunswick found at page 298. It is 24-4 Roman Numeral ii.

MR. LAVIGNE: That was Province of New Brunswick IR-24 part ii?

Q. - 4 Roman Numeral ii.

MR. LAVIGNE: Yes.

Q. - Now the question asked whether or not you took reserves and reserve deficiencies or surpluses into account in your determinations. What is your understanding of the concept of depreciation reserve or deficiency surplus, sir?

MR. LAVIGNE: I am not completely sure but I do know that the straight line method does not require any such deficiencies or surpluses to be taken into consideration.

Q. - You don't know whether other Canadian regulatory jurisdictions have considered the concept of reserve surplus or reserve deficiencies as being when future capital expenditures vary significantly from current estimates?

MR. LAVIGNE: No, I am not aware of that.

MR. PORTER: Just to add, I am not personally aware, but I am sure the amortization review committee would be aware of such concept methodologies being in place in other jurisdictions.

Q. - Further down in the same response, Roman Numeral iii, this is the response in respect of the continuity table that I discussed with Ms. MacFarlane yesterday.

Can you provide a better understanding of why a continuity table cannot be provided? There has been an operating history since 1996, hasn't there?

MR. LAVIGNE: Yes, that is correct.

Q. - All right. So why can't a continuity table be provided?

MR. LAVIGNE: I think it was a combination of the magnitude of the work and the fact that a lot of the details were contained in the response to part 1 of that particular IR.

Q. - All right. And part 1 of that IR, you will agree with me, sir, is simply a year over year change in the amortization amounts for each class of assets. Is that fair?

MR. LAVIGNE: Yes, that is correct.

Q. - It does not deal with the background to how the actual amortization amounts have been calculated, right?

MR. LAVIGNE: No, that is correct.

Q. - And is the level of work that you are referring to, would that also entail statistical analysis to ensure that the continuity in fact has taken place or is accurate?

MR. LAVIGNE: I would expect that would be part of the -- part of the component of that --

Q. - Thank you.

MR. LAVIGNE: -- process.

Q. - Can I take you to table 4 of your evidence please?

MR. LAVIGNE: Yes, I have it.

Q. - I would like to speak now with you about the topic of deferred charges which is found on line 6 of that table. Have you got that?

MR. LAVIGNE: Yes.

Q. - Now, sir, in the asterisk note at the bottom of that table it indicates that this amount includes deferred debt costs, deferred pension benefits and deferred taxes.

Do you see that?

MR. LAVIGNE: Yes, I do.

Q. - Why is it appropriate for the company to earn a return on equity on deferred debt costs?

MR. LAVIGNE: The company is making an investment I guess in these particular areas. And we have deemed it that we should be able to get a return on such.

Q. - You have made an investment?

MR. LAVIGNE: Yes. There would have been a cash outlay for those particular components.

Q. - Who has provided you with the funding to provide provision for that investment? Has it not been the ratepayers through internally generated funds?

MR. LAVIGNE: I'm not sure I follow your question.

Q. - Where is the amount that you require for this investment coming from?

MR. LAVIGNE: I guess I don't see this as any different than any other investment. And it comes from cash flow.

Q. - Cash flow from operations?

MR. LAVIGNE: Yes, that is correct.

Q. - Mr. Lavigne, when you prepared your evidence were you aware of the Board's April 15th 1992 decision?

MR. LAVIGNE: No, I was not.

Q. - This decision -- do you have a copy of that decision, sir?

MR. LAVIGNE: Is that the April 15th 1992?

Q. - Yes, sir.

MR. LAVIGNE: Yes, I do.

Q. - But you weren't aware of this decision at the time you prepared this evidence?

MR. LAVIGNE: That is correct.

Q. - If I could take you to page 21 of this decision?

MR. LAVIGNE: If I could clarify that, the preparation of the evidence was certainly a team effort. Again I was working with the regulatory affairs group who would have had knowledge of these prior decisions.

Q. - Right. If I could take you to page 21 of that decision, sir. I'm under the heading "Cost of service study frequency."

And just to read in the record, starting at the last sentence of the first paragraph, "As a minimum the Board will require that a current cost of service study be filed in connection with any general rate application."

Do you see that?

MR. LAVIGNE: Yes, I do.

Q. - "And further the Board notes that NB Power stated at the hearing that it may perform cost of service studies annually. If so the Board requests that NB Power file a copy of each study with it as soon as available, whether or not a general rate application is planned in that year."

Do you see that?

MR. LAVIGNE: Yes, I do.

Q. - Have those cost of service studies been filed with this Board annually since 1992?

MR. MARSHALL: It is my understanding that there would have been filings through the early '90's up until the time that the Public Utilities Act was changed, amendments were made to the Act, and that regulation of NB Power was then under, dare I say, rate cap or legislative permission structure that did not require a rate increase -- did not require an application of this Board unless there would be a rate increase for greater than 3 percent or inflation.

And from that time on there may not have been filings relative to that until there would be a time for a rate hearing. And this is the first rate hearing before this Board since these generic hearings concluded and since a rate hearing in around 1993, I believe.

Q. - All right. So I think what I take from your answer, Mr. Marshall, is that no -- the obligation to file those ended when there was a change in legislation, that is your view. And now we turn to the present situation where there is a rate application before this Board.

And I'm wondering where you can show me in your evidence that there is a cost of study -- cost of service study found in your evidence. Can you show me where that is?

MR. MARSHALL: The cost of service study for this transmission tariff would be appendix B, the transmission tariff rate design document which breaks down and allocates the net revenue requirement of 98.4 million to the specific services.

Q. - I think, sir, that would be your methodology by which costs are allocated, would it not?

MR. MARSHALL: Based on the services to be provided. That is the cost of service, of providing those services.

Q. - So you don't believe that a cost of service study should analyze whether the costs have been prudently incurred?

MR. MARSHALL: A prudency study would be a different study. Cost of service is what are the costs in the system and how do they allocate to the services that have to be provided?

Q. - I thought -- this takes me by a bit of a surprise. I thought you would be referring me to the Deloitte & Touche study. Is that not an OM&A assessment?

MR. MARSHALL: That is one component of the revenue requirement. But it is the allocating costs to services. The services we are here to approve, ask approval of this Board, are the transmission services in the tariff, and what are the costs associated with providing those services?

That cost allocation, cost of service study is in appendix B of the evidence.

Q. - Can I have you refer to the response provided by New Brunswick Power to Province of New Brunswick information request number 28, part 6?

CHAIRMAN: Which page, Mr. Nettleton?

MR. NETTLETON: I'm at page 304, sir.

CHAIRMAN: Thank you.

Q. - I want to talk now about the largest component of your OM&A expenses. And that is labour?

MR. LAVIGNE: Sorry. We don't have that.

MR. NETTLETON: Okay. Shall we take a pause?

MR. MACNUTT: Would Mr. Nettleton identify the reference again please?

MR. NETTLETON: Yes.

MR. MACNUTT: We have some confusion.

MR. NETTLETON: It is Province of New Brunswick IR-28, part 6.

MR. LAVIGNE: 24. IR-24.

MR. NETTLETON: Sorry. 24. My mistake. I apologize.

No. I'm sorry, sir. It is Province of New Brunswick IR-28, Question 6, part 6.

CHAIRMAN: Page?

MR. NETTLETON: Page 314.

CHAIRMAN: Thank you.

MR. NETTLETON: Now we are back to the number of employees.

Yes.

Q. - Just so that we are clear on the record, Mr. Lavigne, there has only been an approximately 3 percent increase in employees from 2002 to 2003, subject to check?

v MR. LAVIGNE: Subject to check, sounds reasonable.

Q. - All right. And Mr. Lavigne, on table 7 of your evidence it shows approximately a 10 percent increase in labour costs from 2002 to 2003?

MR. LAVIGNE: I'm not sure of the exact percentage. But it certainly looks like it is about 10 percent.

Q. - Subject to check?

MR. LAVIGNE: Subject to check, yes.

Q. - Now if we turn to Province of New Brunswick IR-24, page 304, item 6 --

MR. LAVIGNE: Yes, I have it.

Q. - -- you have provided several reasons for the increase in labour costs.

Were any studies or analyses conducted to look at the prudency of the increased costs?

MR. LAVIGNE: No studies in particular, no. These were costs which were determined from the last set of actuals which we had which was the year ending 2002 and then applying I guess the known increases from labour agreements.

We had the signing of a labour agreement within the last, well, this year, which resulted in some of the larger increase, also taking into consideration the maintenance and capital plans.

Q. - All right. Ms. MacFarlane, I believe my colleague Mr. Smellie spoke to you earlier, early last week about benchmarks and benchmarking studies and whether operational divisions of New Brunswick Power were members of benchmarking organizations.

Do you remember that?

MS. MACFARLANE: Yes, I do.

Q. - And can you today tell us more about whether the transmission business unit has been a member of any benchmarking organization?

MR. LAVIGNE: We are a member of CEA COPE benchmarking group.

Q. - And does the CEA COPE benchmarking group report studies or prepare studies in respect of how members rate against each other?

MR. LAVIGNE: Yes, they have a series of what they call KPI's, key performance indicators, which they use as comparators amongst utilities within Canada.

Q. - Now I recall Mr. Snowdon's evidence some three weeks ago now, that the key performance indicators that New Brunswick Power Transmission is intending to use and form part of this tariff are not CEA key performance indicators. Were you aware of that?

MR. LAVIGNE: I'm not sure of the context which Mr. Snowdon was speaking, so I wouldn't -- I wouldn't want to venture a comment on that.

Q. - Well, can you confirm with me that this tariff, this application is not intending to make reference to or utilize the key performance indicators that only today I am being told New Brunswick Power Transmission is a member of through the CEA?

MR. LAVIGNE: We have not put forth any of those comparators within our evidence.

Q. - Is there a reason for that?

MR. MARSHALL: I believe Mr. Snowdon addressed that at Panel B or Panel D -- that is Panel D evidence. He explained that -- as I recall, he did explain that the CEA data was looked at, reviewed. The differences between utilities were considered. And that the most of the statistics through that are distribution related. There are no specific transmission related data. That the amount of the transmission related data was sketchy and so that it - - it wasn't valid. That NB Power then chose to base its performance on its own five year rolling average in order to improve and put in an incentive to improve performance over time.

I believe that is the testimony of Mr. Snowdon subject to check. It's all on the record.

Q. - As it relates to the key performance indicators that New Brunswick Power Transmission intends to use in this application, namely CADFI and SADFI statistics, can we agree that that is the case?

MR. MARSHALL: Again, subject to check, Mr. Snowdon's evidence.

Q. - But the point, Mr. Marshall and Mr. Levine, is that you are not intending to include any OM&A benchmarking statistics, which you are nonetheless a member of the CEA and participate in those benchmarking studies. And you are not intending to include those benchmarking indices or metrics as part of this application, right?

MR. LAVIGNE: Yes, that is correct. There is a confidentiality clause that we have signed -- well, which all the utilities who participate in this sign. These metrics are meant to be for internal use only and are not meant to be published in a broader form without the written permission of the utilities that participate in this process.

Q. - Why have you not included benchmarking analysis as part of this performance based ratemaking application in the form of benchmarking associated with OM&A costs?

MS. MACFARLANE: I think we have discussed earlier that it -- the difficulty with establishing reasonable comparators given our rural nature, given the necessary robustness of our system with the high industrial load in the northern part of the province and the last number of interconnects relative to our size. But further than that, the PBR mechanism provides in and of itself an incentive for management to reduce costs by use of exogenous factors. And we believe that though benchmarking will be a tool of management to guide them in areas where in fact they can achieve savings, that the PBR mechanism itself should be comfort -- enough comfort to the stakeholders that there is adequate incentive for management to reduce costs.

Q. - Ms. MacFarlane, do you recall our discussion about making sure the starting point revenue requirement is accurate, is right, we have got to get it right?

MS. MACFARLANE: Yes.

Q. - Why don't you think that part of that exercise should apply also to ensuring that the OM&A costs for the purposes of ensuring the starting point revenue requirement are right through the use of OM&A benchmarking?

MS. MACFARLANE: I think the fact that it's very difficult for NB Power to establish appropriate benchmarks for OM&A given the nature of our system, given the rural elements, the industrial load, et cetera, makes it very difficult to do that.

There was an attempt to do that in the Stone & Webster study and I think that has been put in evidence. But it's difficult to find OM&A benchmarks for our utility. Things like number of employees per mile of line, et cetera, are difficult to measure in a rural area compared to a -- to an urban area.

Q. - Those would sort of be the same sorts of reasons why it's difficult to carry out a depreciation study for those very -- for the depreciation assets, the assets that you have. Would that not be true?

MS. MACFARLANE: We do carry out depreciation studies. I think Mr. Lavigne has made that quite clear. Every category of assets is subject to study once every five years.

Q. - But in terms of the statistical analysis that you carry out, and the fact that you take into account how other jurisdictions and utilities operating in other jurisdictions, the statistical analysis associated with those other jurisdictions, you take that into account, I believe, if I understand Mr. Lavigne. Or at least the amortization review committee takes that information into account. Why would you not take it into account -- that type of information into account with the OM&A?

MS. MACFARLANE: I'm not suggesting that we don't take it into account. You asked if it was part of the evidence here. And we said that it was not part of the evidence here.

We have looked for benchmarks, and have looked at benchmarks. And have tried to get behind the numbers to understand why they may or may not be different than our numbers. And why they may or may not be appropriate.

But it is -- it is a difficult undertaking. And as I say, it's evidence to such in the Stone & Webster study.

Q. - Can you show me where in the Stone & Webster study it says that it's impossible for New Brunswick Power to utilize OM&A benchmarking?

MS. MACFARLANE: I think you have misquoted me. I did not say it was impossible. I said there was an attempt made in that study. And they too experienced difficulty in doing it, but I do believe it was part of the study.

Q. - But you have -- why then, Ms. MacFarlane, would New Brunswick Power be a member of a benchmarking organization if ultimately you believe the results are meaningless?

MS. MACFARLANE: I don't believe I said the results were meaningless. I said it's very difficult to find an exact comparator and it's a lot of work to get behind the numbers. That doesn't mean it's an invaluable or meaningless exercise.

Q. - Do you think it would have some value to ensuring that the starting point revenue requirement, as you are applying for in this application, is right?

MS. MACFARLANE: We are quite confident that the starting point as we are applying for in this application is correct. We have a number of years history in terms of our OM&A costs, they are relatively stable. The costs are virtually entirely related to maintenance. Maintenance is directly affecting reliability. That was studied in the Stone & Webster study. We are confident that these going in OM&A rates are reasonable.

Q. - Would benchmarking studies not assist you though, or assist ratepayers such as my clients, in understanding and making sure that the band widths around the ROE are appropriate?

MS. MACFARLANE: To the extent that it would require probably days and days of hearing time to understand what is behind the numbers and why they may or may not be appropriate utility -- as a utility benchmark for NB Power, given the characteristics of our system we did not feel that it was useful and valuable beyond what was provided.

Q. - You are presuming that there would be a hearing in that case, right?

MS. MACFARLANE: If it was part of the evidence, it would be part of the hearing.

Q. - You don't think consultation outside the hearing room with ratepayers would have been a way to facilitate that objective being completed?

MS. MACFARLANE: I am not aware that that's part of this process.

Q. - Oh, I'm quite aware that that is not part of this process. What I'm asking you is would that not have been one way to ensure that ratepayers, the very parties that you are expecting to obtain cost savings from in your PBR mechanism, would have had some level of comfort with the PBR scheme that you are proposing. And included with that level of comfort, understanding about the reasonableness of your OM&A numbers by way of benchmarking them to other utilities?

MS. MACFARLANE: Mr. Nettleton, the process that's laid out in the legislation for review of these things is a process like this. That is public. It allows for intervenors to ask whatever questions they want to ask in the form of inquiries. And to attend a formal hearing like this. That's the process we played out in New Brunswick.

Q. - A very costly one though, right?

MR. MARSHALL: That's a judgment.

Q. - Well, I know the judgment of my clients view on that point. All right. Let's move on. Back to table 7, Mr. Lavigne. I'm interested in line item 10 entitled "High Voltage Direct Current OM&A". Do you see that?

MR. LAVIGNE: Yes, I do.

Q. - My simple question on that item, Mr. Lavigne, is what does it relate to?

MR. LAVIGNE: That is a facility at the border of New Brunswick, at the interconnection with Quebec.

Q. - All right. Why would it not be appropriate to have those OM&A costs capitalized as part of that asset?

MR. LAVIGNE: These are not capital costs. These are labour, materials, hired services related to running that particular facility.

Q. - Why has it been excluded or detailed out or taken out of the other categories for your OM&A costs?

MR. LAVIGNE: This particular facility was previously managed on behalf of transmission by the generation business unit and has subsequently been charged out to transmission, thus we handle it a little differently than our direct transmission costs.

MS. MACFARLANE: The reason for that, by the way, is physical proximity of plants that we have in the north and therefore staff that we have in the north to this particular station.

Q. - What -- on what basis has there been this allocation or charge out, as you call it?

MR. LAVIGNE: These are all the costs associated with that facility. These are designated employees to the facility or designated hired services, materials, so on. So they are well, designated to the facility. So they are fairly easily definable.

Q. - Are there any service agreements associated with those HVDC facilities?

MR. LAVIGNE: Currently we do not have any service agreements with that particular facility.

Q. - Have you had them in the past? You said currently.

MR. LAVIGNE: No, not in the past either. If I could clarify a little bit. In the new world which is donning, we do suspect that there will be some requirement for shared services between the generation and transmission business unit or companies.

Q. - So let me understand this then. These are not transmission employees, these are generation employees that are managing transmission assets?

MR. LAVIGNE: Currently that is the case.

Q. - And in the brave new world, will this be the subject matter of some form of agreement made between Genco and Transco?

MR. LAVIGNE: The agreement is that these employees would be moved to transmission. They would become transmission employees.

Q. - And so in years in the future will these costs then simply be reported as part and parcel of the other line items comprising table 7?

MR. LAVIGNE: I expect they would be handled no differently than any other direct transmission cost. So the answer is yes.

Q. - Thank you. Mr. Marshall, back to you, sir. If you could turn up Saint John Energy information response number 8 and I will find a page number here. It is page 480, Mr. Chairman.

CHAIRMAN: We have it.

Q. - I'm hoping that you are going to be referring to this IR but my question is this, what are the extra costs anticipated to be associated with the independent system operator that we spoke of yesterday? Is it the $500,000 that you are forecasting?

MR. MARSHALL: The -- it's my understanding the $500,000 here forecasted for OM&A relates to additional costs at the energy control centre relating to the opening of the market and operating of the market. It's NB Power costs as NB Power originally filed this tariff. It does not include any additional costs for an independent system operator at this time.

Q. - Do you have any idea or any forecast of the independent system operator costs at this time?

MR. MARSHALL: No, I do not.

Q. - But what we can agree upon is that the independent system operator costs -- what we can agree at this time is that the independent system operator costs are not included as part of this tariff filing, is that right?

MR. MARSHALL: That's correct. Again, you go back that this tariff was filed as an integrated utility for a tariff for the basis of the market. The -- it's unknown exactly the structure the system operator will take, how big an organization it will be. That is subject to legislation and we were not going to speculate on that. These are the direct related costs we feel are necessary in order to provide a fair open access tariff from our system and our people.

MS. MACFARLANE: Could I just add to that to avoid any alarm on behalf of your client, it isn't anticipated though. The function is performed today. It is performed today by the transmission business unit and it is not anticipated that the separation will provide hugely different costs than it does today through to -- through one entity. There may be additional costs required of the governance panel to monitor the market, but in terms of actually operating the market, our staff do it today. It would be anticipated that those staff would either be moved to or seconded to an ISO and there would not be hugely additional costs.

Q. - It seems like the cart is before the horse here. We have an application for a tariff filing that does not include costs for an independent system operator, yet that is the intent -- that is the net result of this application, is it not? Aren't you intending to have that happen?

MS. MACFARLANE: As Mr. Marshall said, the application was filed as an integrated utility. They are separate from this application. And since this application there has been an announcement by the Minister that he intends to separate system operations. But I repeat, the system operations are performed today. The system does function today. And the costs of functioning are represented in the costs included in this tariff today. The legislation may require that the management of the tariff itself move to the ISO. It may require a number of things. But it will in all likelihood not lead to huge amounts of additional costs beyond what is done today, other than potentially from -- other than potentially from monitoring the effectiveness of the market.

MR. NETTLETON: One moment, Mr. Chairman.

Q. - Mr. Marshall, based on the testimony provided by Ms. MacFarlane I just want to confirm that this application was filed and prepared under the assumption that there was not an ISO, is that right?

MR. MARSHALL: It was filed and prepared. Yes, the decision on an ISO was taken and came out publicly I believe in August. This tariff was filed on the 25th of July. It was actually prepared in many months prior to the 25th of July.

Q. - Yes or no, Mr. Marshall, this application was prepared and filed under the assumption that there would not be an ISO?

MR. MARSHALL: There was no --

Q. - At the point of market opening.

MR. MARSHALL: No, it was not -- there was no assumption whether there would or would not be an ISO. The tariff was filed as an integrated utility to provide transmission services to operate the system.

Q. - Nowhere in your application, Mr. Marshall, does it indicate that the transmission service would be administered by an independent system operator, is there?

MR. MARSHALL: No. And nowhere does it say it wouldn't be.

Q. - But didn't we just hear, Mr. Marshall, that there is no costs associated with an independent system operator included in this application?

MR. MARSHALL: Other than the costs associated with additional expenditures arising from the market and opening the market. And as Ms. MacFarlane said the intention is to -- that the costs are associated with people, salaries, space and that the same people operating the system today we expect will be operating the system after the -- if there is an independent system operator set up, as we are waiting for legislation. That that would be a secondment of people and the same people, their costs are -- those people are going to operate the system. Their costs are in this tariff today.

Q. - Why did you not when you prepared this evidence, Mr.

Marshall, indicate that it was your intention for New Brunswick Power to use an independent system operator or organize its affairs, as yet I'm assuming another butterfly or maybe it's a hawk, to ensure that the operation functions of the transmission component would be operated independently from Transco? That wasn't your intent, was it?

MR. MARSHALL: No, the -- our intent was to file a tariff to provide for fair rates for the cost of providing a service. The issue is whether or not the government will go forward and change legislation and set up an independent system operator.

And at the time that the tariff was prepared and filed, there was no definitive position of what form that would or would not take, so the tariff was filed as an integrated utility, as we currently remain today, NB Power Corporation. We filed it before this Board.

Now the implementation of the tariff may or may not be undertaken by an independent system operator. If one exists and if the legislation passes and there is an independent system operator, then I expect they will be empowered and will administer and implement the tariff. But that is speculative.

Until that happens this is a tariff for provision of services that can be administered and done by NB Power with the existing people that are there.

Q. - All right. Mr. Chairman, would you wish to take a break at this point?

CHAIRMAN: Then we will take our break.

(Recess)

CHAIRMAN: Go ahead, Mr. Nettleton.

MR. NETTLETON: Thank you, Mr. Chairman. There is one preliminary matter that I would like to advise the Board of. During -- before the start of this afternoon's session, the information, the background information to exhibit A-23 was provided to my clients by Mr. Porter. And we are in the process of reviewing it. Obviously not now. But we will be doing that over the evening and I'm hoping to then be able to continue my cross examination on that issue tomorrow.

So just to -- I wanted to ensure that you were aware that that information has now been provided.

CHAIRMAN: When you -- if you want to have a little later start in the morning just let us know.

MR. NETTLETON: Thank you. Let's see how today goes. I'm hoping that we can get through everything but that area, so I will let you know how we are going. Thanks.

Q. - Before the break, Mr. Marshall, there was some confusion over the ISO, and Ms. MacFarlane, with respect to the cost of the ISO. And I would like to try and put some finality around that issue.

Mr. Marshall, is it your understanding that as of the opening of the market April 1, 2003, there will or will not be an ISO?

MR. MARSHALL: It is my understanding at this time there will be.

Q. - Thank you. And Ms. MacFarlane, your testimony before the break was that in respect of incremental costs associated with the ISO, that (a) those costs are not reflected in this application. Is that correct?

MS. MACFARLANE: I believe I said I didn't expect that there would be significant incremental costs.

Q. - We will get to the amount. But just that they are not in this application right now. Right?

MS. MACFARLANE: To the extent that they exist --

Q. - Right.

MS. MACFARLANE: -- the only thing in the tariff is the $500,000 allocation that Mr. Marshall referred to.

Q. - All right. And any incremental costs above that, your expectation is that they would not be large in terms of quantity and amount?

MS. MACFARLANE: My expectation is that there would not be any costs in excess of that. It is not -- again I have just been party to discussions about the fact that it is not the government's intent to burden ratepayers with additional costs through the restructuring of the market or the restructuring of NB Power. Adding an ISO is not being done so as to add exorbitant costs which have to be collected through rates.

The system is operated today by NB Power. I believe the thinking is to separate that chunk of NB Power activity and have it done under a separate governance structure.

Q. - All right. And Ms. MacFarlane then, is it fair to say that the function that you expect to be carried out by the independent system operator, there are costs included in table 7 specifically, that is the operations, maintenance and administration that will relate to the ISO function. Is that fair?

MS. MACFARLANE: Yes. This represents costs that include the energy control centre, which today handles the system operations function.

Q. - And similarly in respect of the fixed assets associated with carrying out the independent system operator function, those are included in your evidence in respect of the fixed assets, correct?

MS. MACFARLANE: Again these items are very much subject to finalization. But it is our understanding that in all likelihood the ISO would rent space in the existing energy control centre. And so from that perspective the fixed asset costs are included here.

Q. - All right. So I think that was a yes? Yes, there are -- the independent system operator fixed assets are included in the fixed asset numbers included in this application?

MS. MACFARLANE: To the best of my understanding, yes.

Q. - All right. And, Mr. Lavigne, you have indicated that in the past separate facilities that have been in effect undertaken those facilities -- those transmission facilities have been undertaken by other groups or functions of New Brunswick Power Corporation such as the HVDC facility have been reported as a separate line item, right?

MR. LAVIGNE: Yes, that is.

Q. - So do you expect, Ms. MacFarlane or Mr. Lavigne, that when the market opens that there will be separate accounting and reporting of the costs -- all costs associated with the independent system operator?

MR. LAVIGNE: Yes, that will be the case. There will be separate accounting for those particular costs.

Q. - All right. Mr. Lavigne and Ms. MacFarlane, I think you guys can take a break now. Mr. Marshall and Mr. Porter.

I would like to take you to your presentation C materials. And unfortunately I wasn't here on Thursday. And I don't know the exhibit number.

MR. MARSHALL: A-26.

MR. NETTLETON: Thank you. A-26.

CHAIRMAN: A-26.

MR. HASHEY: It is at A-7 I believe in the binder.

CHAIRMAN: Thank you, Mr. Hashey.

Q. - Mr. Marshall, do you have your presentation materials before you?

MR. MARSHALL: Yes.

Q. - I would like to first turn to slide 5 which is entitled Step 1, defined principles. And I believe during your presentation, at least from the transcript at page 1,330 you indicated that transmission is a regulated cost of service business, right?

MR. MARSHALL: Yes.

Q. - Would you agree that only costs that have actually been incurred and prudently incurred to provide regulated service should be recovered in rates under this tariff?

MR. MARSHALL: The rates that should be recovered under this tariff are all the costs that we have put forward in the revenue requirement.

Q. - That wasn't my question, Mr. Marshall. I will repeat my question. And if I could have a yes or no answer. And if you want to add another explanation feel free. But if you could just answer the question.

Would you agree that only costs that have actually been incurred and prudently incurred to provide regulated service should be recovered in rates under this tariff?

MR. HASHEY: Mr. Chairman, I don't want to mislead here. And I don't want to interfere with the answer. But there is an Act. And there is a provision in the Act that governs this. And this is a legal question.

MR. NETTLETON: Well, Mr. Chairman, I don't believe it is a legal question at all. Mr. Marshall indicated in his presentation at transcript 1,330 that transmission is a regulated cost of service business. And I'm trying to elicit from this witness his meaning of that phrase which he has used.

CHAIRMAN: What part of the statute are you referring to, Mr. Hashey?

MR. HASHEY: Section 62 of the Public Utilities Act.

CHAIRMAN: What was the question again?

Q. - The question is would you agree that only costs that have actually been incurred and prudently incurred to provide regulated service should be recovered in rates under this tariff?

CHAIRMAN: And you object, Mr. Hashey, on the basis that Section 62 covers, and that therefore it is a legal question?

MR. HASHEY: That is right. It is up to the Board to decide what has to be recovered. And it has to be guided by the Act, I would suggest, Mr. Chairman.

CHAIRMAN: Yes. Would you reword the question, Mr. Nettleton?

Q. - When you indicated during your presentation that transmission is a regulated cost of service business, what costs or type of costs were you suggesting should be recovered through rates?

MR. MARSHALL: All of the costs associated with the pie chart on page 8 of the presentation, being the total revenue requirement of 98.4 which has been now amended down to 97.9 million, made up of OM&A costs, amortization, finance charges, return on equity and payment in lieu of taxes. All of those costs are prudent costs to be recovered in rates.

Q. - And are all of those costs actual costs that NB Transmission will incur? Actual costs to provide service.

MR. MARSHALL: Based on the projected change in legislation for the new entity and Ms. MacFarlane's testimony

yesterday, they will be legal obligations and legal costs that cover all of those, to provide the service.

Based on the current application before this Board, they are the costs, the full costs on an equivalent level playing field basis that should be charged for service to third party users outside the province, and therefore because of nondiscrimination, charge equally to customers inside the province.

Q. - So there may be costs that aren't actually incurred by New Brunswick Power Transmission to provide the service that you are offering, correct?

MR. MARSHALL: It is our understanding under restructuring all of these costs will be borne by NB Power Transmission or whatever the name of the corporation is.

Q. - Well, let me give you an example, Mr. Marshall. Suppose there were plans to construct new facilities at some point in the future, yet the facilities had not actually been constructed and no money had been paid for them.

Would it be proper for such facilities to be put into rate base at some fictional amount? Would that result in just and reasonable tolls?

MR. MARSHALL: The -- again my understanding of the legislation, the current legislation that this Board is reviewing this tariff under, is that our obligation is to put in a projection of all of the costs required to provide the service.

So in your case of a facility to be added in the future, if it is in the test year, the year of the service, it is a projection of the costs and should be reviewed and included.

Q. - And what if it is not in the test year? What if there was some projection five years from now, it wouldn't be prudent to include those costs, would it?

MR. MARSHALL: Under this tariff the -- the test year costs set the base year. And then it is a -- the PBR formula would take precedence from there to move forward.

Q. - Mr. Marshall, I'm not talking specific to this application. I'm trying to understand what you meant by the phraseology of a cost of service regulated business, and also from slide 5 your concept of the words that are included in that slide of just and reasonable rates.

Do you think rates would be just and reasonable if the facilities that had not yet been constructed, and there had been no money actually incurred for the construction of those assets, would it be just -- would just and reasonable rates result if those facilities were included in rates, and there was no forecast of those facilities happening during the test year?

MR. MARSHALL: If I understand your question, you are saying if there is money put in --

Q. - No. No money. No money has been actually incurred.

MR. MARSHALL: I understand that. A projection of a future expense for future assets included to provide for the -- in the rate base today in these rates? Would that be just and reasonable? Is that --

Q. - Yes.

MR. MARSHALL: -- what your question is? No, it wouldn't be.

Q. - Thank you. And Mr. Lavigne, is that in part the reason why you have excluded from these rates work in progress?

MR. LAVIGNE: The work in progress moved as a result of conversations with Dr. Morin in terms of the used and usefulness of that particular component of the rate base.

Q. - Is that a yes?

MR. LAVIGNE: Would you ask the question again?

Q. - Is that why you are not including work in progress in the calculation of rate base in respect of this tariff?

MR. LAVIGNE: Again it came down to consultation with Dr. Morin who had previously not had an opportunity to discuss this particular component with, and through our conversation with him we deemed that it was incorrect to include this in the rate base.

Q. - I will move on. Let's turn to slide 26. Mr. Marshall, you have indicated at slide 26 four different pricing methods that you considered for the pricing of ancillaries, do you see those?

MR. MARSHALL: Yes.

Q. - Now you will agree with me, sir, that you evaluated the pricing methods prior to filing this application, is that right?

MR. MARSHALL: We considered them all.

Q. - Prior to filing the application, right?

MR. MARSHALL: Yes.

Q. - These aren't tough questions, seriously. So it was done under the assumption that there would not be an ISO when the market opens, correct?

MR. MARSHALL: I believe I responded to that earlier. We were preparing the tariff a year ago at this time and doing work through the whole -- the year. So we did not have in indication of an ISO until -- in some level of independence until May 30th when it was announced by the government, and the fact that that independence would take the form of an ISO until into August. So we did not consider the ISO in -- we did not know of an ISO prior to reviewing these and filing the tariff.

Q. - All right. So I think the answer is yes. So it was done under the assumption that there would not be an ISO?

MR. MARSHALL: I think I responded to that before. It wasn't done under the assumption that there would be or that there wouldn't be. We were aware of market design committee's recommendations on independence of the operation of the system. We did not know what form it would take or where it would go, and we were preparing a tariff based on a FERC 888 tariff that could be applied for as an integrated utility.

Q. - Now you have rejected the method known as embedded costs because, as I understand it, the potential for confidential information or commercial confidential information being disclosed, is that right?

MR. MARSHALL: That's correct.

Q. - Is this concern now not addressed given that there will be an ISO in place when the market opens?

MR. MARSHALL: In what way?

Q. - Well in the way that there is an independent system operator who would be provided with the information associated with the embedded cost of providing ancillaries. It's an independent system operator, Mr. Marshall.

MR. MARSHALL: The -- in the current legislation it's this Board that has authority over rates for ancillary services and the tariff.

Q. - I understand that, Mr. Marshall, but your reason, as I understand it, to reject embedded cost relates to having confidential data of commercial value disclosed. Is that not the reason why you rejected embedded costs?

MR. MARSHALL: That's correct.

Q. - And is that reason now not mitigated by the fact that there will be an independent system operator upon the opening of the market?

MR. MARSHALL: No, because the independent system operator would still have to come to this Board with an application for pricing of the ancillary services and the information of the generation would still be made public through this process, or one like it. So there is no guarantee of protection of the commercial value of the information.

Q. - So if the commercially sensitive information provided to an independent party such as an ISO where the Board could be protected, that concern would be mitigated, fair?

MR. MARSHALL: If it could be completely protected, yes.

Q. - Like filing under seal?

MR. MARSHALL: Yes.

Q. - And it's your view, is it, Mr. Marshall, that the proposed standard of conduct for the ISO remains sufficient to ensure information by the ISO will not be disclosed?

MR. MARSHALL: Yes.

Q. - Thank you. Now we turn to the second reason why you rejected embedded costs. You say it may over or under value the resource. Do you see that?

MR. MARSHALL: Yes.

Q. - Would you agree, Mr. Marshall, that the embedded cost methodology is used for the development of the revenue requirement for the point-to-point and network integration system rates?

MR. MARSHALL: Yes.

Q. - Do you have concerns that these tariffs under value or over value the transmission service provided by New Brunswick Power Transmission?

MR. MARSHALL: No. As I said, the transmission is a regulated cost of service business. So whatever those embedded costs are are the basis of calculating the transmission costs in a tariff.

Q. - So why would you not be consistent and apply the same model or method to ancillary services?

MR. MARSHALL: Because we are moving to a market and there is potential for -- NB Power Generation and other generators have to participate in that market. Release of their information disadvantages them in the market. NB

Power Transmission is not participating in the market. They are a monopoly transmission supply that will provide regulated rates for customers to deliver products into the market. That's why they are a regulated entity.

Q. - Is it not appropriate for a commercially incentivized company to try and provide the lowest cost of service to ratepayers?

MR. MARSHALL: Yes. That's why we proposed the PBR mechanism, to provide that incentive to lower O&M costs and provide value through this application.

Q. - I thought I heard your answer, Mr. Marshall, indicate that it would not be fair to Generation and somehow be uncompetitive or anti-competitive in the generation field if embedded costs would be used for the price of ancillaries. Am I wrong?

MR. MARSHALL: That's correct. You shifted over to Transmission. I thought we were still talking about Transmission.

Q. - We will get there. Can you answer the question?

MR. MARSHALL: Could you repeat it, please, because I'm not quite sure which one we are talking about now?

Q. - You indicated that there would be some unfairness or uncompetitiveness in pricing ancillaries using an embedded cost methodology, and that would be for Generation, right?

MR. MARSHALL: Yes.

Q. - Why would the competitiveness of Generation be of concern to Transco if Transco is a commercially incentivized company intending to provide the lowest cost for service? Shouldn't you be incentivized to try and minimize your cost of providing service?

MR. MARSHALL: Yes.

Q. - Well then why did you select embedded cost? Sorry, why didn't you select the embedded cost methodology?

MR. MARSHALL: Because it would have to reveal commercially sensitive confidential information which would disadvantage the generators that have to provide those services.

Q. - Who are those generators, Mr. Marshall?

MR. MARSHALL: Today they would be NB Power Generation, Bayside Generation, and depending upon how the market goes forward and how the system operator procures the services, it could be WPS Energy Services, could be JDI if they do a project, it could be Irving Oil.

Q. - During the test year though, Mr. Marshall, would you not agree that all of the ancillary services that are going to be provided are going to be provided only by New Brunswick Power Generation?

MR. MARSHALL: The services to be provided under this tariff that we have applied for are under the assumption that they are back-up services to be provided by NB Power Generation, that they are the default ancillary services, yes.

Q. - You don't take issue with the R.J. Rudden report at -- where it indicates that NB Generation will be providing the ancillary services during the test year period, do you?

MR. MARSHALL: No, I do not, although they may not be the 100 percent provider of those services. There will be from time to time other possible generators that may be providing some portion of those services. But they certainly are the predominant supplier.

Q. - So are you -- when you raise this unfairness or anti-competitiveness concern, what hat are you wearing, Mr. Marshall? Are you wearing the NB Generation hat or NB Transmission hat?

MR. MARSHALL: Well we are here again as the only legal person that can appear before this Board is NB Power Corporation.

Q. - But is the concern that you are raising a Generation concern or a Transmission concern?

MR. MARSHALL: It is a Generation concern.

Q. - All right. So it shouldn't factor into a reason or justification for Transmission to accept a methodology by which ancillaries are provided, should it? You are the buyer of the service, Mr. Marshall.

MR. MARSHALL: Yes. And if we are strictly Transmission and the Generation people would not make the confidential information available to us unless we kept it confidential, we wouldn't be able to do embedded cost.

Q. - Well we are back to --

MR. MARSHALL: The issue is they don't want it -- they want the information remained confidential.

Q. - And why doesn't an independent system operator, if it's truly independent, why couldn't they be the recipient of this information?

MR. MARSHALL: They could be the recipient of it under their code of conduct and protect it, but in order to develop a tariff using it they would have to come to this Board and the information would then be public.

Q. - Aren't you making an assumption?

MR. MARSHALL: I'm just going by what the current law is. This Board has jurisdiction over the tariff and ancillary services and it would require an application or approval of this Board.

Q. - But we heard this morning during your discussion with Mr. MacDougall that that type of information is information that has been reported on publicly in other jurisdictions such as the FERC, correct?

MR. MARSHALL: That was my understanding from what he stated, yes.

Q. - Let's turn to the next pricing method, which is short run marginal costs. Does New Brunswick Power know what its marginal costs are for generation?

MR. MARSHALL: Yes.

Q. - Since short run marginal costs are difficult to measure, as you suggest, aren't long run marginal costs even more difficult to measure since they depend on knowing not just short run marginal costs but also many other factors?

MR. MARSHALL: The issue here is -- I go back to just clarify my previous answer. Short run marginal costs, when we say we know what they are today, we know what our short run marginal energy costs on production of units are. To know what the actual short run marginal cost of providing ancillary services are, we do not. It's very difficult to measure what they are specifically. What is the incremental O&M at one unit from a pulse to an AGC unit. What effect does that have on the -- on the margin. So they are very, very difficult to measure.

So we know short run marginal costs of energy from the generators, but we don't have specific short run marginal costs from provision of ancillary service.

And I might add, the other -- another reason why I said in the presentation that short run marginal costs are not a good method to use for ancillary services, is that they would definitely undervalue the service. Because they would not have a capacity contribution to fixed costs.

Q. - Well, we will get there, Mr. Marshall. And I'm sure the JDI and CME the panels will have -- panel will be happy to answer lots of questions on this.

But back to slide 26 where you say it's difficult to measure highly variable and provide inadequate incentives. Are you aware of other markets where ancillary services are priced in an open and competitive marketplace?

MR. MARSHALL: Yes, I am

Q. - And would your expectation be that those suppliers of ancillary services would be pricing such services using short run marginal cost methods?

MR. MARSHALL: I believe they would be supplying services with some indication of their short run marginal costs and what contribution they could get the fixed costs out of whatever they believed the market would be.

Q. - All right. So it's not an impossible task. It's simply that you haven't undertaken that task. Is that fair?

MR. MARSHALL: Well, I think the key issue is that they would have some indication of those costs. We say it's difficult to measure at every point in time. It's the adder that they would get as a contribution to fixed costs that is the key part of any -- of any price from these bid based markets.

Mr. Porter just pointed out that in these bid based markets whether the -- the risks on whether the supplier is wrong on his marginal costs or what price he bids, he takes the risk of that. The only key issue is what price does he bid, and whether that price is lower than the competitive price and it's accepted in the market.

Q. - And that's the risk taken by the generation company?

MR. MARSHALL: That's correct.

Q. - It's not transmission, right?

MR. MARSHALL: In a bid based market it's the bid comes from a generation company in a competitive market, they carry the risk.

Q. - It's not transmission, right?

MR. MARSHALL: No, it's not. It would be generation takes the risk of the bid.

Q. - Now, Mr. Marshall, when I reviewed the transcript at page 1347, and I think you have repeated this here, you indicated here today. You indicated that one of the problems was the undervalue ascribed to the service since it would not provide a contribution to capital costs of the system. Is that fair?

MR. MARSHALL: It would not provide a contribution to the fixed costs of the generator providing the service.

Q. - Right. Let's just test that, can we? I would like to run you through a hypothetical, if I could.

Suppose you had only two power plants of a hundred megawatts each. One with a short run marginal cost of $20 and the other with a short run marginal cost of $30. Under short run marginal cost pricing, if both power plants run, and assume that it is only these two in the market, then the price or short run marginal cost would be $30. Correct?

MR. MARSHALL: What is the load?

Q. - 200.

MR. MARSHALL: Then the short run marginal cost would be $30, yes.

Q. - Right. Now the power plant with costs of $30 would earn nothing above its short run marginal costs since the price paid was $30, right?

MR. MARSHALL: Yes.

Q. - But the power plant with costs of $20 would earn $10 for every megawatt generated, since the price paid was $30.

That is 30 minus 20, correct?

MR. MARSHALL: Well we are making a few assumptions here. You are assuming this is a bid based market with a -- that the price paid to all generators in the market is the market clearing price?

Q. - The assumption, Mr. Marshall, is that the short run marginal cost method by which prices are determined is being used.

MR. MARSHALL: So they are -- are they both paid? If they are both paid their short run marginal costs, one would be paid 20, one would be paid 30. If they are both paid a clearing price on the marginal cost, then they both would be paid 30.

Q. - It's the latter?

MR. MARSHALL: Okay. Then if they are paid 30, the second generator would get a $10 contribution to its marginal cost -- to its fixed costs.

Q. - To its fixed costs?

MR. MARSHALL: Yes.

Q. - All right. So there is no disagreement that the fixed costs contribution would be provided to the plant owner with the $20 short run marginal cost, right?

MR. MARSHALL: If it was that nature of a bid based market, he would get some contribution. The other generator at the $30 marginal cost would have no contribution.

Q. - Okay. And in that scenario, if both generating units are owned by the same party, then what?

MR. MARSHALL: That I guess you could share the $10 contribution between the two.

Q. - But ultimately that differential would be available for fixed costs, correct?

MR. MARSHALL: Yes, if you have a bid based market.

Q. - And what about a short run marginal cost market, are they one and the same in effect?

MR. MARSHALL: In a short run marginal cost market where you are clearing at the marginal cost of the -- of the unit providing the service, there would be some contribution to fixed costs for other generators, but not for the generator that is providing the marginal service.

Q. - Thank you. The hypothetical is over.

Let's go back now to slide 26. And let's talk a little bit about the last unit, or the last pricing method and that's long run marginal cost.

Before we do this, let me understand, Mr. Marshall, that your current tariff does or does not include provision for ancillaries?

MR. MARSHALL: Our current tariff, you mean the out and through tariff that currently exists?

Q. - Yes.

MR. MARSHALL: It has provision for system control and dispatch and for voltage support -- reactive power voltage support. It does not have in it any capacity based ancillary services.

Q. - And the capacity based ancillary services -- and I have referred to his as one of my favourite meals, CBAS. CBAS is a new service that arises as a result of you now applying for a FERC pro forma tariff, FERC 888 pro forma tariff, is that right?

MR. MARSHALL: It arises because the old tariff was for out and through transmission was point to point only. There was no network service and there was no provision for internal delivery service and competition to municipals or parties inside the system. They were still all customers of NB Power. So the ancillary services were all still monolopy services provided through bundled rates to the customers in the jurisdiction. So there was no need for any of those services and they were not put in the tariff.

So this application now, because it is a network service application as well as point to point, and the intention of market design to be compatible to FERC order 888, includes all of the ancillary services.

Q. - All right. The FERC 888 proforma tariff makes provision for CBAS, correct?

MR. MARSHALL: Yes.

Q. - Right. And that is one reason why you are including this new service in your current application, fair?

MR. MARSHALL: Yes.

Q. - Thank you. Now is there a method included in the FERC pro forma tariff by which prices for ancillaries must be priced or the pricing of which is mandated. Do you know that?

MR. MARSHALL: We are not aware of any cookie cutter method that FERC has for pricing ancillaries, no.

Q. - Mr. Marshall, who developed the proxy unit method to price CBAS? Was it you?

MR. MARSHALL: It was done collectively. Mr. Porter had a lot of input and did most of the work. Mr. Scott and myself were involved.

Q. - And did you consider having any third party expert provide advice to assist you with this topic? That is the appropriateness of pricing CBAS using proxy units?

MS. COWAN-MCGUIGAN: Excuse me, what does CBAS mean?

MR. NETTLETON: Sorry, capacity based ancillary services. I understand it's late in the day but I'm --

CHAIRMAN: I hate to tell you, but it's an endangered species in New Brunswick.

MR. NETTLETON: Is that because you like it too, sir?

CHAIRMAN: I used to fish it when I was a boy, but you can't do it anymore.

MR. MARSHALL: Your last question, Mr. Nettleton, please?

Q. - Did you have any third party expert provide advice or assist you in developing the long-run marginal cost proxy unit method, the price in generation ancillaries?

MR. MARSHALL: It was reviewed by Mr. Garwood of Rudden, his overall review of the tariff application and what we have put forward.

Q. - Mr. Marshall, do you agree that any method adopted to price generation ancillaries should adhere to cost causation principles?

MR. MARSHALL: Reasonably so, yes. Certainly on the service side the cost causation of what customer loads put on the system and what they use in terms of those services.

Q. - What they actually use?

MR. MARSHALL: Yes. We believe ancillary services should be based on cost causation.

Q. - Actual costs?

MR. MARSHALL: As we have applied in this tariff in this case, proxy unit costs which are reasonable costs for provision of those services.

Q. - So proxy unit costs, not actual costs?

MR. MARSHALL: Proxy unit costs in this application, yes. And charged to services to the customers based on their usage of those services.

Q. - All right. Let's go to slide 27 please. Is it fair to say that slide 27 deals with the objectives of the pricing methodology that you are proposing?

MR. MARSHALL: We put those forward as what the rationale and the benefits of long-run marginal cost pricing are using proxy units for ancillary services.

Q. - Why was the first rationale or objective not to provide -- or sorry, why was the first objective to provide adequate compensation to the supplier?

MR. MARSHALL: There is no relevance to the order.

Q. - Why is it there at all?

MR. MARSHALL: If we don't provide adequate compensation to the supplier for the provision of the service, you may not have the services to provide to customers and may not be able to reliably operate the power system. So it is in the interests of all load customers in the system that we procure those services.

Q. - Mr. Marshall, I want to go through another hypothetical with you. I don't think you are going to need a pen. Let's assume you are in the market to buy a car. Are you concerned when you make that purchase about the financial health and well-being of Ford?

MR. MARSHALL: Well, I may be a little concerned about maintenance down the road that they would be operating.

Q. - Aren't you concerned about getting the best deal?

MR. MARSHALL: If it is a Ford?

CHAIRMAN: You be careful.

MR. MARSHALL: I would like the best deal, yes. And the hypothetical is an analogy to what we are doing, is that we -- again these are maximums to be set out in the tariff.

And where services can be procured at a lower price they will be procured at a lower price. And so if I can go buy a car at a better deal someplace else, I will go buy the car at the best deal.

Q. - Let's make the assumption that Ford is the only car manufacturer out there. How are you going to do that?

MR. MARSHALL: If Ford is the only car manufacturer then I need to rely on the Competition Bureau or some form of regulation like this Board to set some type of cap on that price so that I'm protected. And that is why we are here, for this Board to review this tariff.

Q. - Then you discuss mitigation of market power. And I think we can certainly agree, or at least my clients can certainly agree with you, that that is one of the foremost and primary objectives. But then you go on and talk about transparency. And would you agree that that -- the transparency and predictable pricing, are linked?

MR. MARSHALL: Yes. I believe Mr. Porter spoke to that this morning when -- under cross examination of Mr. MacDougall.

Q. - And then you talk about the pricing not being site-specific. Do you see that?

MR. MARSHALL: Yes.

Q. - Now as I understand it, Mr. Marshall, from your presentation, there are only going to be two facilities that provide ancillary services?

MR. MARSHALL: That is not the case. There are two predominant facilities that would provide a lot of the services. They will not be the only facilities.

Q. - When you say "predominant" how much in terms of percentage do you mean? Do you want to take that as an undertaking?

MR. MARSHALL: Oh, I could give you a ballpark I think. The fact that the Mactaquac station is an energy-limited hydro station, whenever there is not enough water to fully utilize the station, then it has reserve capacity available so provides the spinning reserve and supplemental reserve a lot of the time or a good portion of it.

In the high water months when it is not available -- its most economical use is to run it to generate energy, then it is necessary to provide the reserves from other sources. And that is the case then it comes from Coleson or from Belledune or Dalhousie, whatever other thermal units are running on the system.

And if there is a need to use the hydro system then you would have to redispatch the hydro down and have a dispatch cost to make hydro available. And that is the nature of the system.

Q. - I understand the nature of the system. But I guess what I was getting concerned with was at page 1,347 of your tariff -- or of your -- I hope your tariff isn't 1,347 pages. From the transcript you had indicated that only the Mactaquac and the Coleson Cove stations would be providing ancillary services?

MR. MARSHALL: Well, that was a slip. If I said that I want to correct that. They are the predominant suppliers but not the only suppliers.

Q. - Back to the percentage, meaning of the word "predominant", do you have that?

MR. MARSHALL: Between the two of them they would probably provide I guess 80 to 90 percent.

Q. - Thank you. Why is it a good thing that we not consider actual pricing for the ancillary services arising from these two facilities?

Aren't you sending an artificial price signal to the marketplace by not using actual cost of the facilities that provide the service?

MR. MARSHALL: No. Again we don't have a market here for ancillary services. The issue is the mitigation of market power.

If we are going to have a bid-based market for ancillary services then the owner of Mactaquac and the owner of Coleson Cove, being the only two -- the predominant players in the market would have market power. That is the issue.

What we are trying to do in this tariff is to provide a reasonable price which will provide an adequate compensation to the supplier and that is a regulated cap essentially on the service.

Q. - Shouldn't it be --

MR. MARSHALL: And customers in the tariff have the right to self-provide the services or to go buy them from someone else, if they can buy them cheaper.

So essentially what this application does is place a cap in the marketplace on the price of ancillary services.

Q. - Mr. Marshall, if you are concerned about market power and you are concerned about the price by which ancillary services are offered and provided by Generation, isn't that a topic that should be saved for another day before this Board, about the proper pricing of ancillary services by NB Generation?

MR. MARSHALL: The -- no. I believe that what we have put forward is a reasonable set of prices on a reasonable basis that this Board can judge and say that is a reasonable cap to put on the price of ancillary services in the market to customers.

The tariff, as I said, provides the opportunity for customers to go buy it from anybody they can find it from.

Q. - Why wouldn't --

MR. MARSHALL: If it causes market power you need to put a cap on it to mitigate the market power.

Q. - Why wouldn't that market power mitigation be mitigated -- it is getting late. Why wouldn't that market power be mitigated through the use of a cap based on actual cost?

MR. MARSHALL: Because those costs would then have to be made public through a forum such as this and would commercially disadvantage the generators that are supplying the services.

Q. - And assume for me for a minute that there wasn't that disclosure to the public, that there was disclosure to the regulator or to an independent third party. Would your concern be addressed?

MR. MARSHALL: I would think if there was a guarantee of nondisclosure of information then embedded costs, with proper rate of return, reflecting market participation of those types of units, and payment in lieu of taxes to meet the government's requirement for a level playing field, then I think that that would be possible --

Q. - Thank you.

MR. MARSHALL: -- if there was a guarantee of that protection of the information.

Q. - Thank you. Let's turn to your next point on slide 27. And that is "Predictability and transparency are objectives." Do you see those?

MR. MARSHALL: Yes.

Q. - And do you believe the proposed methodology will meet those objectives?

MR. MARSHALL: Yes.

Q. - Well let's test that. Is it correct that the amount that NBP charges for CBAS may be more than what it pays for CBAS and that revenues exceeding cost will be rebated to customers?

MR. PORTER: That potential exists. But what is more likely to happen is that the rates -- if the cost of procurement by the transmission provider of the ancillary services is less than what was projected in the application, the rates would be discounted under the terms and conditions of the tariff.

Q. - So there would be use of some form of deferral account or something of that nature?

MR. PORTER: There would be a discount in the actual rates charged to customers.

Q. - All right. So are you going to be automatically -- or discounting automatically at the time that the service is provided, or is there going to be some lag?

MR. PORTER: The ancillaries are intended to be a straight pass through of these costs, no mark up by the transmission provider. So to the extent that it's possible to do so, the rates would be adjusted dynamically to avoid over collection of revenues, or --

MR. MARSHALL: And the way that that can be done is in the ancillary service charges there is an out-of-order dispatch cost that is going to be accrued monthly at the end of the month charge. Any credits or reductions would be into that account, and so it would be a cost or credit there. You have a monthly true-up based on the actual costs.

Q. - Sure. And just for the purposes of this discussion can we just refer to that amount as the CBAS rate pool or rebate pool. It is getting late. Can we agree to use that term? You will understand what I mean by it as that flow through in a future month period of that difference? Is that fair?

MR. MARSHALL: I think it's intended to be at the end of the month based on actuals for that previous month.

Q. - All right. That's fine. Now is it also true that NBP -- that New Brunswick Transmission has the discretion to offer CBAS at discounted rates?

MR. MARSHALL: That's correct.

Q. - Why would New Brunswick Power Transmission want to do this, to offer discounts?

MR. MARSHALL: If a customer is self-providing the ancillary services or if they can go buy it from somebody else in the market and provide it at a lower price by discounting the service, the supply -- there would be competition for the supply. So it's basically the only means that NB Power Generation, being the default supplier, and this is a cap on their prices, it's the only means by which they can compete in the marketplace against others that can self-supply or buy from others.

Q. - So in order to compete with others who could self-supply you would offer the discount?

MR. MARSHALL: For people who might self-supply or for people who are mainly purchasing from other suppliers.

Q. - So then New Brunswick Power Transmission, in choosing to discount, is doing so on behalf of New Brunswick Power Generation so that in fact New Brunswick Power Generation can compete, fair?

MR. MARSHALL: Basically in this application the way it's laid out, that would be correct, because this again FERC Order 888 is an application where the transmission provider as an integrated utility has the obligation to provide these services, and it's from their generation unit. So this is essentially a regulated cost of the ancillary services from NB Generation delivered through the transmission provider to customers.

Q. - Can you go back to slide 27 for a second, Mr. Marshall.

MR. MARSHALL: I have it.

Q. - How does the fact that New Brunswick Power Transmission acting on behalf of New Brunswick Power Generation mitigate market power?

MR. MARSHALL: The pricing mitigates the market power by placing a cap on the price.

Q. - We are not talking about the cap, sir. We are talking about the discount. By you being able to discount for the purposes of allowing New Brunswick Power Generation to compete in the marketplace, how does that mitigate market power?

MR. MARSHALL: Well that's a market. Then you are competing based on prices. Market power is exerting your market power to get higher prices and exorbitant prices out of customers that have no protection. You know, competing -- the cap places the protection of customers for market power below that, you are in competition with customers to provide services.

Q. - Do you know what the concept of predatory pricing is, Mr. Marshall?

MR. MARSHALL: I am not an economist but I have some general concept to what it might be.

Q. - Don't you think that by New Brunswick Power Transmission discounting ancillaries on behalf of New Brunswick Power Generation, that's a form of predatory pricing as it relates to others wanting to compete in that marketplace?

MR. MARSHALL: No, I don't think so, because the quantity of ancillary services required to operate this system is pretty significant. And the new entrant into the market would be providing only a share of those. In order to avoid that party from being able to supply in the market, you would have to discount the value on all the ancillary services, which would not be in the interest of the generator. So there is still room for parties to come in and participate in the market.

Q. - Mr. Marshall, why would anyone want to come into this marketplace and compete when it knows that the incumbent that has over 80 to 85 percent of the marketplace for ancillaries is able to offer discounts to match whatever price is being offered by its services or by the competition?

MR. MARSHALL: Well first of all, parties will not come into this market just to provide ancillary services. Ancillary services are a very small piece of the value of generation. Parties will come into the market in order to do bilateral contracts.

And in order to supply customers who have loads in the system under either network or point-to-point, if they are load customers inside the system, the reliable operation requires all of these ancillary services. So NB Power Generation, providing these services as a back-up through the tariff, enables people to come into the market. It's not -- it doesn't block them from the market. It actually helps them to come into the market because they have a guaranteed knowledge of what the cap would be on the ancillary services that they require to come into the market. Their value they will gain from the sale of energy through their bilateral contracts.

Q. - Mr. Marshall, when a discount is offered on CBAS will it be offered to all transmission customers?

MR. MARSHALL: Yes.

Q. - So can any transmission customer take advantage of this? For example, can a network customer that ordinarily elects to pay the scheduled rate monitor the OASIS site and whenever discount rates are posted simply inform New Brunswick Power Transmission that it wants the discounted rate instead?

MR. MARSHALL: No. The network customers sign service agreements for a year and will take either -- they can self-provide or they can contract for the service, but it's not -- ancillary services in this market are not hourly services you can opt in and out of.

Q. - So then not all transmission customers will be able to get any discount offered, fair?

MR. MARSHALL: If the discount is offered it would go to all network service customers, all customers taking service.

Q. - I'm sorry. I thought you said that a discount that was offered or posted on the OASIS system would not be available to network customers that ordinarily elect to pay scheduled rates. Am I missing that?

MR. MARSHALL: I said that the network customers are going to take service under an annual contract in the tariff. They can self-provide or they can contract from some party to provide or they can take it under the tariff. That's their choice. But they don't opt in and out hour to hour, week to week. They decide up front they are going to do it on an annual basis.

Q. - And so those customers are precluded from any discount on CBAS that is offered or posted on OASIS, fair?

MR. PORTER: Which customers?

Q. - Those customers that are locked into the scheduled rates.

MR. PORTER: They receive the discount.

Q. - They do?

MR. MARSHALL: I think they receive the discount, subject to check. Actually the questions of the implementation of the tariff and how the discounts would be applied are questions that should have been asked of Panel D, Mr. Scott and Mr. Snowdon. But we can undertake to clarify that, just to check with them.

Q. - Well, Mr. Marshall, you do refer to discounts in your presentation at page 31, do you not?

MR. MARSHALL: What I'm saying is that yes, the -- what we say in the rates that these are the rates and they are maximum rates and that they may be discounted. Now how they are discounted is through the implementation of the tariff and the actual tariff document which was the evidence of Panel D.

Q. - I understand that, Mr. Marshall, but we are now talking about the benefits of your long run marginal cost pricing proxy unit methodology, and two of those factors are transparency and predictability. And I'm trying to understand how those objectives are met when discounting is offered by NBT. And I'm trying to understand how predictability and transparency are met in the sense where some but not all transmission customers may avail themselves to discounts that are

offered by the
transmission service
provider. \So --

MR. MARSHALL: The -- well the transparency is in the methodology that Mr. Porter talked of this morning. The methodology to develop the price is clearly transparent and on the record of this hearing.

The rates are transparent and known to everyone in the market place. The fact that they are there and they are known, they are predictable, parties can then budget what they require. They can -- whether they can go buy it some place else or they take it here, it's very predictable what they are going to do.

Q. - Can they budget --

MR. MARSHALL: If there is a discount then there will actually be a reduction in their costs, and I don't think customers would be upset with that type of a reduction.

Q. - I understand that, Mr. Marshall. I'm trying to understand predictability. All right. Can they budget on a predictable basis what the discount is going to be?

MR. MARSHALL: Now you are into the market interaction and predicting what the market price of ancillary services is in a bid based market is extremely precarious. So what the -- once you get into the influence of the market as to what may happen with the discount there is some difficulty in forecasting and predicting what that is. What is predictable and clear and transparent is the maximum rates that are in the schedules.

Q. - Well we will get there, Mr. Marshall.

MR. PORTER: I may add to that that one of the big drivers behind the potential for discounts is what we talked about a few moments ago, is that as other participants come into the market and are able to offer up the service at rates that are lower than what is built into this based on the proxy units, the transmission provider will blend these new lower costs with the cost based on the proxy units and that blended cost will be lower and that's what will result in the discount in the ancillaries. That's not something that is going to happen rapidly and jump up and down over time. That's -- if there is truly downward pressure on those rates then that will be a transition over time.

Q. - Will discounts ever be offered at a price below the cost of purchasing the service? For instance, if New Brunswick Power paid $20 for some amount of CBAS would it ever offer it at $10?

MR. MARSHALL: I doubt it. But again that was a question for Mr. Scott.

Q. - Would you agree, Mr. Marshall, that it's fair to say that the availability and the size of the discounts are going to be hard to predict and are variable in nature?

MR. MARSHALL: As a market -- as a market develops and there are other players in the market that provide these services, then I would agree with you. Initially because there are not a lot of providers of these services, the taking the basic rates should be pretty predictable. But as it -- a market develops projecting what the discounts may or may not be will be more volatile, yes. Just as any other market is.

Electricity is a volatile market. The most volatile of all market products in the world.

Q. - Now one of the criticisms that you have for their pricing methods for CBAS is that one would end up with rates that are variable. Correct? If you flip back over to page 26, and I am in particular looking at short-run marginal costs being highly variable. Do you see that?

MR. MARSHALL: Yes.

Q. - And in addition to the rates in the schedules that you have included as your transmission tariff, transmission customers that take CBAS from New Brunswick Power Transmission will have to pay redispatched costs. Correct?

MR. MARSHALL: Yes.

Q. - How predictable will redispatched costs be?

MR. MARSHALL: I think that the dispatched costs should be reasonably predictable by the system operator. They are done on a day ahead and a go forward basis. The system is short of outages of units or significant changes in the system, the load is a generally reasonably predictable amount. It may vary significantly in the winter depending on temperature and things. But if you have a forecast of load and you know the generators that are on, so that I think that the projection of out of order dispatched costs is reasonably predictable by the system operator.

Q. - Have you provided any evidence in this application as to the predictable nature of redispatched costs? Is there any statistical data that shows the conclusion that you are suggesting is true?

MR. PORTER: It's predictable in that if we could have -- we didn't project that there would be out of order dispatched costs. The potential is there. If system conditions change, if ECC requirements change, the potential is there. But our prediction in the short term is that there would not be substantial out of order dispatched costs. If we had been able to predict substantial costs, we would have actually built them in and had that evaluation under the review of this process.

Q. - Right. So as I understand it, Mr. Porter, if they were predictable, they would have been included as a rate in your tariff? Fair?

MR. PORTER: No, I said there is a degree of predictability. And if we had predicted -- we had projected that there would be substantial costs, we would have built them in and had this Board review the calculation of those costs.

Q. - I am not asking about the substantiveness of the costs. I am asking about the predictability of the costs. And I am suggesting to you, sir, that if the costs were predictable, you would have included it as a rate, would you not?

MR. PORTER: My response is that it's predicted to be small enough then it didn't need to be added into this rate application.

MR. MARSHALL: And it occurs from time to time with the outage of a generator the certain system conditions that occur. That's why it would be allocated on a monthly basis.

Q. - So if it's --

MR. MARSHALL: There are some months when it would occur more than other months. For instance in the high hydro months, there is a higher probability of some redispatched costs than there are in the months when the hydro is -- has got lots of available capacity to provide the services.

Q. - Well why wouldn't you have included a maximum for redispatched costs if they weren't significant just like you have with ancillaries? Wouldn't that add to the predictability for the purposes of ratepayers?

MR. MARSHALL: I guess we would again run the risk here or need of an additional true-up mechanism doing that. The intent was that the out of order dispatched costs would be based on the actual costs of out of order dispatch in that it really only can be occurred -- determined accurately after the fact hour by hour based on the actual system costs.

Q. - So it sounds like it is unpredictable in terms of you have to know what's happened, right?

MR. MARSHALL: It's predictable. The way the system operates is that they will do a schedule on a week ahead and a schedule on a day ahead in that that schedule from day ahead is when you have to commit units and make sure units are going to meet all your requirements for ancillary services and load. And then as you go through the day there may be changes in load and other things that happen.

Q. - How small are these costs going to be Mr. Marshall?

MR. MARSHALL: I believe Mr. Porter addressed that.

Q. - I didn't hear a dollar figure. How small in terms of dollar amounts are we talking about?

MR. MARSHALL: I don't have a specific estimate of what those costs would be.

Q. - So Mr. Marshall, let's just see if I follow what is included in the tariff. A transmission customer that takes CBAS from New Brunswick Power Transmission will pay for CBAS the scheduled rate minus any discount, plus any redispatched costs, minus any rebate from what I call the CBAS rate pool. Is there anything else?

MR. MARSHALL: The other thing that would add any energy imbalance penalties, power factor penalties or other miscellaneous revenues would go into that true-up account as well.

Q. - I'm sorry. Other miscellaneous revenue, power factor and energy imbalance. All right.

So the transmission customer pays a stable scheduled rate for CBAS plus or minus account 6 variable factors, correct?

MR. MARSHALL: They are not just related to CBAS. The penalties on power factor would be credited to all customers. We are assuming here that most of the customers or network service customers are paying for these ancillaries, they would -- those adjustments on the penalties, all right, are not -- are to be handed back to customers. They would get credited back on this monthly adjustment.

Q. - Let's go back to 27, page 27. And I'm just wanting to understand how you feel this meets your criteria of predictable and of transparent rates.

So how does it do that, Mr. Marshall? You have got at least three variable costs included in the rate that is ultimately charged to ratepayers. How are predictable rates created under this methodology?

MR. PORTER: We are talking about the predictability in the capacity component of the rate charged. Items such as out of order dispatch could be either under long or marginal cost pricing or embedded cost pricing or in the bid base such as in the ISO New England market where generators are paid an additional payment if there is out of order dispatch. And that gets charged out to customers.

So I think the level of predictability of the out of order dispatch is independent of the choice of the methodology for pricing these ancillary services, that is the choice of long or marginal costs versus the other three methods that were considered.

MR. NETTLETON: Thank you, Mr. Porter. Mr. Chairman, I'm going to be moving to a different area now.

CHAIRMAN: So am I, Mr. Nettleton. 9:30 start in the morning all right, sir?

MR. NETTLETON: Absolutely.

CHAIRMAN: Okay. We will adjourn until then.

(Adjourned)

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

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