NEW BRUNSWICK ENERGY & UTILITIES BOARD

IN THE MATTER OF an Application dated May 1, 2008 by New Brunswick System Operator (NBSO) for the approval of changes to the Open Access Transmission Tariff

held at the Delta Hotel, Saint John, New Brunswick on October 27th 2008

Henneberry Reporting Service

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IN THE MATTER OF an Application dated May 1, 2008 by New Brunswick System Operator (NBSO) for the approval of changes to the Open Access Transmission Tariff

held at the Delta Hotel, Saint John, New Brunswick on October 27th 2008

BEFORE: Raymond Gorman, Q.C. - Chairman
Cyril Johnston - Vice-Chairman
Yvon Normandeau - Member
Donald Barnett - Member
Roger McKenzie - Member

NB Energy and Utilities Board - Counsel - Ms. Ellen Desmond
- Staff - Doug Goss
- John Lawton

Secretary of the Board: Ms. Lorraine Légère

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rmc CHAIRMAN: Good morning, everyone. This is a hearing of the New Brunswick Energy and Utilities Board in relation to an application being made by the New Brunswick System Operator for the approval to changes to the Open Access Transmission Tariff.

The New Brunswick System Operator in its application also requested that the Board issue an interim order pursuant to Section 40 of the Energy and Utilities Board Act approving the changes to the Schedule 1 rates to be effective from the date of such interim order until further order of this Board.

The Board approved that interim rate change on June the 12th, 2008 effective as of July 1st 2008 with the interim rates to be in effect until a final order of the

Board is made in this application.

The Board on a Motions Day on August the 18th, 2008 at which time a motion was brought forward by Mr. MacDougall on behalf of Integrys Energy Services, requesting the Board to approve the Settlement Agreement with respect to the surplus.

The Board determined that the settlement was tied to the changes to the OATT and that it would not prejudge any elements of the application.

Accordingly, the Board determined that the Settlement Agreement would be considered by the Board at the full hearing of the application for changes to the Open Access Transmission Tariff, in other words at today's hearing.

The panel for this hearing consists of Don Barnett, Roger McKenzie, Yvon Normandeau, Cyril Johnston and myself Raymond Gorman.

At this time I will take the appearances starting with the Applicant.

MR. KENNY: Good morning, Mr. Chairman. On behalf of the Applicant Bob Kenny and Kevin Roherty appearing as counsel.

And with me are the witnesses for NBSO, Mr. William Marshall, Ms. Lynne West and Mr. George Porter. And behind me is Marg Tracy and Norm Seely, NBSO regulatory staff and also Mr. Jean Finn, Vice-president of NBSO is present as well.

CHAIRMAN: Thank you, Mr. Kenny. The Intervenors, start with Bayside Power. I understand that we received a letter from Mr. Hoyt that he would not be present. Integrys Energy Services Inc.?

MR. MACDOUGALL: Good morning, Mr. Chair, Commissioners. David MacDougall on behalf of Integrys Energy Services Inc. And I'm joined today by Mr. Ed Howard.

CHAIRMAN: Thank you, Mr. MacDougall. NB Power Distribution and Customer Service Corporation?

MR. MORRISON: Good morning, Mr. Chairman. Terrence Morrison. And with me at my counsel table is Blair Kennedy, Nicole Poirier, John Furey, in-house counsel at NB Power and Arden Trenholm.

CHAIRMAN: Thank you, Mr. Morrison. How does it feel to be on that side of the room?

MR. MORRISON: Very good indeed.

CHAIRMAN: New Brunswick Power Generation Corporation?

MR. MORRISON: Ditto, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Morrison. Northern Maine Independent System Administrator?

MR. BELCHER: Ken Belcher, Northern Maine ISA.

CHAIRMAN: Thank you, Mr. Belcher. Nova Scotia Power System

Operator? My understanding is that they were not going to be present today. And Oxbow Sherman?

MR. MORRISON: Mr. Chairman, we received a call from Stacy Dimou of Oxbow Sherman. I believe he was going to try to contact the Board. He will not be able to attend today.

CHAIRMAN: Thank you, Mr. Morrison. Public Intervenor?

MR. THERIAULT: Good morning, Mr. Chairman, Board members. Daniel Theriault. And with me this morning is Robert O'Rourke and Teann Hennick.

CHAIRMAN: Thank you, Mr. Theriault. New Brunswick Energy and Utilities Board?

MS. DESMOND: Ellen Desmond, Mr. Chair. And from Board Staff, Douglas Goss and John Lawton.

CHAIRMAN: Thank you, Ms. Desmond. I understand that there are a number of documents to be marked as exhibits. When we -- I guess at our last hearing at Motions Day we ended at exhibit A-10. And there have been I believe four more documents that we have received since that point in time. And I will mark those as exhibits at this point in time. I believe the exhibits list was circulated. And I don't believe the Board has received any indication that anybody has any objection.

So exhibit A-11 would be DBR Enterprises Inc. Proposal for Consulting Services dated November 7th 2005 provided as a result of the Board's August the 18th, 2008 ruling and submitted under cover letter from Kevin Roherty dated August 25th 2008.

Exhibit A-12, Business Bridge Statement of Work for NBSO Strategic Planning 2007 dated June 18th 2007 provided as a result of the Board's August 18th 2008 ruling and submitted under cover letter from Kevin Roherty dated August 25th 2008.

Exhibit A-13, EA Energy Analysis agreements dated November 6th 2007 and December 18th 2007 provided as a result of the Board's August 18th 2008 ruling and submitted under cover letter from Kevin Roherty dated August 25th 2008.

A-14, Responses of NBSO dated September 3rd 2008 to Interrogatories dated August 26th 2008 in relation to exhibit A-5, Clarification of Tariff Changes document, responses submitted under cover letter from Kevin Roherty dated September 2nd 2008.

Are there any other documents, Mr. Kenny, that should be marked?

MR. KENNY: Yes, Mr. Chair. The c.v.'s of the witness panel, Mr. Marshall, Ms. West and Mr. Porter have been forwarded to the Board.

And Mr. Roherty has -- and they have been forwarded to all parties. So Mr. Roherty has those. Perhaps you may want to mark those.

CHAIRMAN: I believe they were forwarded to all of the parties as well.

MR. KENNY: That is correct, Mr. Chair.

CHAIRMAN: All right. Then the three c.v.'s will be marked as follows. Exhibit A-15 will be the c.v. of Mr. William Marshall, President of WMK Consultants Inc. and former NBSO President and CEO.

Exhibit A-16 would be the c.v. of Mr. George Porter, NBSO Director, Market Development and Settlement.

And exhibit A-17 will be the c.v. of Ms. Lynne West, NBSO Controller.

And does that take care of all of the documents at this time, Mr. Kenny?

MR. KENNY: That is correct, Mr. Chair.

CHAIRMAN: Thank you. With respect to procedure this morning, it is the Board's understanding that there is a single panel of witnesses being put forward by the applicant and that no other parties have indicated that they would be presenting any evidence through witnesses. Since today's hearing involves both the application for a change to the Open Access Transmission Tariff and the settlement with respect to the surplus, the parties will cross-examine the witness panel with respect to both issues when their turn for cross-examination arises.

Any preliminary matters before we start with the witnesses?

MR. KENNY: I have brief opening remarks that may give some guidance to just exactly what this is about, Mr. Chair.

CHAIRMAN: Okay. Just before we hear those opening remarks, anybody else have any preliminary matters?

All right. Mr. Kenny, then proceed.

MR. KENNY: Mr. Chairman and Members of the Board, there are really two components to this hearing. So for the sake of clarity I wish to outline briefly the chronology of how we got here and indicate very clearly to the Board the items for which the NBSO seeks the Board's approval.

The first component to be looked at is Board reference 2008-003 which is a review of the methodology for the allocation of the operating surplus of the New Brunswick System Operator.

It arose out of the request from the NBSO for approval of the distribution of surplus funds for the fiscal year 2007-2008.

As everyone knows, the issue around surplus funds was a mismatch between the costs and revenues related to the capacity based ancillary services, otherwise known as

CBAS, which was producing a substantial surplus along with a shortfall of revenue under schedule 1, the schedule meant to fund NBSO operations.

The result was a cross-subsidization under which the CBAS surplus was being used to offset the revenue shortfall under schedule 1.

Everyone recognized that this cross-subsidization should not continue and that action needed to be taken to more properly align costs and revenues for the various ancillary services.

So without going through the various technical conferences and meetings which were held to deal with this surplus issue, suffice to say that the result of proceedings under Board reference 2008-003 to this point was a submission to the Board of what has become known as the, and I quote, "Settlement Agreement".

This agreement is before the Board as part of the proceedings and can be found in exhibit A-5 under its own tab.

In brief it proposes to resolve the dispersal of surplus funds for 2007-2008 and 2008-2009, while at the same time creating a mechanism for dealing with surpluses or deficits which occur in the future.

The second component is Board reference 2008-007. And that is the application by the NBSO made May 1st 2008 for changes to the Open Access Transmission Tariff which is marked as exhibit A-1.

In its original form this application sought approval of revised rates for schedules 1 and 2 as well as for CBAS services. Schedule 2 rate changes were minor.

But the increase sought for schedule 1 to offset the projected revenue shortfall was so important in terms of timing the NBSO sought and received interim relief, the result of which was the implementation of a schedule 1 increase on July 1st 2008.

Revision to the CBAS rates were intended to properly align costs and revenues for these services, as noted earlier.

And so as of May 1st we have had these two matters before the Board at the same time. And as we all know, the two are related, in that certain portions of the methodology related to the Settlement Agreement require changes to the tariff.

The Board recognized this. And in a letter dated July 18th 2008 directed the NBSO to clarify the matter and identify the specific changes to the tariff for which the NBSO seeks Board approval.

The NBSO did so and filed what has become known as the, and I quote, "Clarification Document" that has been identified and marked as exhibit A-5.

That document indicates that the NBSO is proposing to move away from fixed rates for schedules 1, 2, 3, 5 and 6 to establishing new rates for wind generators and to make two changes in Board policy. Details of these items and related supporting evidence are found in exhibit A-5.

And so, Mr. Chair and Board members, that is the background that brings us to today. In summary the NBSO is requesting Board approval of the following.

Number (1) approval of the distribution of surplus funds for 2007, 2008 as proposed in the Settlement Agreement filed with the Board by Mr. David MacDougall on June 19th 2008. Number (2) approval of the schedule 1 rates implemented on an interim basis from July 1st 2008. NBSO proposes that these rates remain in place until March 31st 2009. (3) approval of revised charges for schedule 1 effective April 1st 2009, moving away from fixed rates to an annual approval of schedule 1 Revenue Requirement consistent with the Settlement Agreement. (4) approval of revised charges for schedule 2 effective April 1st 2009, moving away from fixed rates to an annual approval of a schedule 3 Revenue Requirement. (5) approval of revised charges for capacity based ancillary services, which are schedules 3, 5 and 6, effective December 1st 2008,moving away from fixed rates to a methodology whereby customers' monthly charges are based on the actual monthly expenditures for these services consistent with the Settlement Agreement. And (6) approval of rates for regulation and frequency response services to be charged to wind generators effective April 1st 2009 which is schedule 3, paragraph (c).

Additionally, the NBSO seeks Board approval of the following two changes to Board policy. (a) cessation of the retained surplus account as of April 1st 2009 and (b) replacement of a fixed cap on CBAS self-supply with an allowable range of 85 percent to 100 percent.

Mr. Chairman, Members of the Board, those are the specific items for which the NBSO seeks approval. In terms of process, it is our understanding that no one has objected to the Settlement Agreement and that many have specifically approved it. And therefore support its approval by the Board.

More specifically, the agreement itself was filed by Mr. MacDougall on behalf of Intervenors, Integrys Energy Systems Inc. and Northern Main Independent System Operators.

Additionally, the Board is in receipt of letters from

Mr. Terry Morrison dated June 19th 2008 on behalf of the New Brunswick Power group of companies and from Mr. Kevin Roherty on behalf of NBSO dated June 20th 2008. Both of these letters support the Settlement Agreement and recommend its approval.

So it is the suggestion of NBSO, Mr. Chairman and Board, that we deal first with the Settlement Agreement. In the absence of any filed evidence opposing the agreement and stated support for the agreement I have just described, we assume that the Board approval is justified.

Acceptance of the Settlement Agreement in principle would significantly simplify the hearing. It would resolve reference 2008-003 with an accepted surplus distribution for the fiscal year 2008-2009. It would resolve the issue of moving away from fixed rates and introducing monthly settlements.

As such the balance of this hearing would amount to examination of schedule and costs and the specific changes to the tariff and Board policies I have just described.

Thank you, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Kenny. Perhaps you can just clarify for me that your remarks are, towards the end, about approving the Settlement Agreement, are you asking the Board to consider that before the evidence with respect to the OATT application?

MR. ROHERTY: Mr. Chairman, what the NBSO is suggesting is that there has been no evidence filed contrary to the Settlement Agreement. We are also prepared I guess to file the letters in support of the Settlement Agreement the Board is already in receipt of and really put that issue before the Board.

In our view all the evidence has been filed in respect of the Settlement Agreement. And the issue is now fully before the Board, as we understand it.

CHAIRMAN: Well, there may be however parties that wish to cross-examine the panel for example with respect to that settlement. And I don't really know how we could deal with it before we deal with the OATT.

As I understand it, there are elements of it that essentially require part of the application to be approved.

MR. ROHERTY: That is fine, Mr. Chairman. I guess it was our understanding that all the evidence was there. But certainly it is open to cross-examination. And perhaps we could just I guess proceed on that basis then.

CHAIRMAN: And I will go back to my introductory remarks when I did comment that we would not have the panel come forward twice, that if anybody did have a question with respect to the settlement that they would ask the panel those questions when it was their turn to ask questions with respect to the OATT.

MR. ROHERTY: That is fine, Mr. Chair.

CHAIRMAN: Any other preliminary matters? Perhaps you can call your panel at this time then.

MR. KENNY: Mr. Chairman, I'm going to call Mr. William Marshall, Mr. George Porter and Ms. Lynne West to be sworn.

CHAIRMAN: Perhaps Board Counsel could come forward and swear the witnesses.

<u>(William Marshall, George Porter and Lynne West sworn)</u>

CHAIRMAN: The witnesses have all been sworn, Mr. Kenny.

<u>DIRECT EXAMINATION BY MR. KENNY</u>:

Q.1 - Mr. Marshall, would you state your name and position for the record please?

MR. MARSHALL: William K. Marshall. I'm Past President, retired of New Brunswick System Operator.

Q.2 - Was the evidence before the Board today, which is represented by exhibits A-1 and A-5, as well as the responses to all the Interrogatories marked as exhibit A-4, A-6 and A-14 prepared under your direction as President and CEO of New Brunswick System Operator?

MR. MARSHALL: Yes. While I was President and also since while I have been retained as a consultant to carry through the process of this hearing.

Q.3 - Do you adopt this evidence as your own for the purpose of this hearing?

MR. MARSHALL: Yes, I do.

MR. KENNY: Thank you, Mr. Marshall.

Q.4 - Mr. Porter, would you state your name and position for the record please?

MR. PORTER: George Porter, Director of Market Development and Settlement.

Q.5 - And you as well have read the evidence before the Board in this application?

MR. PORTER: Yes, I have.

Q.6 - Do you adopt this evidence as your own for the purpose of this hearing?

MR. PORTER: Yes, I do.

Q.7 - Do you have -- I believe we have some corrections that we would like to make, Mr. Porter. I might -- just some -- I believe they are typos?

MR. PORTER: Yes. That is correct. Starting with exhibit A-1, the exhibit A-1, tab 5. And there is a tab labeled F. It is red line tariff excerpts. And it is page 94 within that section.

Now I will just go through that once more in case anyone missed that. But it is exhibit A-1, tab 5 in the colored tabs. And there is a white tab labeled F. The section title is red line tariff excerpts. And it is page 94.

The correction is in the column called Start Gate. The dates there -- the April 1st is applicable in all cases. But the years, rather than being as is shown there, they should read from top to bottom. They should read 2009, 2010, 2011 and 2012.

Mr. Chairman, that same correction also applies, the identical correction in two other places within the evidence. And they are in exhibit A-5.

So exhibit A-5, the white tab labeled Schedule 3, and page 94. Again exhibit A-5 is a white tab with black lettering which is labeled Schedule 3, and page 94.

And once again the years change from what they are. And I will read from top to bottom. They become 2009, 2010, 2011 and 2012.

CHAIRMAN: I think Mr. Johnston is ahead of you. He has got it at page 95. But I think he is probably going to your next change.

MR. PORTER: Well, thank you very much for that. Yes. The next change would be under -- the labeling is red, red text. It also says Schedule 3. And in that case it is page 95. And again the change will be that the years change to read 2009, 2010, 2011 and 2012.

Mr. Chairman, there is one additional unrelated revision to make. And it is in exhibit A-6.

So exhibit A-6 which are the responses to Supplemental Interrogatories. And look for the tab that says GENCO. It will be response to the Supplemental IR-2 from GENCO. Do you have that, Mr. Chairman?

CHAIRMAN: Yes.

MR. PORTER: Okay. Towards the bottom of the page, the third line from the bottom of that page there is a line which reads, Assumed 316 megawatts of tie benefits from New Brunswick.

That number 316 is an error. The number should be 360.

CHAIRMAN: 360?

MR. PORTER: 360, Mr. Chairman.

CHAIRMAN: Thank you. Just give us a moment.

MR. PORTER: Thank you, Mr. Chairman. That is the end of the corrections.

CHAIRMAN: Anytime you are ready, Mr. Kenny.

MR. KENNY: Yes.

Q.8 - Ms. West, would you please state your name and position for the record please?

MS. WEST: Lynne West. I'm the Controller at New Brunswick System Operator.

Q.9 - And do you accept this evidence as your own for the purpose of this hearing?

MS. WEST: Yes, I do.

MR. KENNY: That is the evidence on behalf of the Applicant, Mr. Chair, and subject to any redirect.

CHAIRMAN: Thank you, Mr. Kenny.

Mr. MacDougall, I think you would be first on behalf of Integrys Energy Services.

MR. MACDOUGALL: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MACDOUGALL:

MR. MACDOUGALL: It is probably Mr. Porter or Mr. Marshall for most of the questions that I'm going to ask today. And I will leave it to you two gentlemen to determine who is best to respond. But some may be for Ms. West as well.

Q.10 - If we could first look at exhibit A-6. And if we could look at Integrys Supplemental IR 4-A which is at page 13 under the Integrys tab.

Q.11 - And here you indicate that the NBSO has not conducted any bencmarking studies to compare its staffing levels and salary benefits to comparative system operators, correct?

MS. WEST: That is correct. We have not conducted any benchmarking studies ourselves.

Q.12 - Okay. When you say yourselves, just because you added the yourselves, has someone else conducted benchmark studies referable to salaries for the NBSO?

MS. WEST: Not that I am aware of, no.

Q.13 - Okay. Thank you. And then if we could just flip forward a bit to page 19 Integrys Supplemental IR-18. And here you have provided a copy of a proposal from K. Gordon and Associates which was a proposal for a compensation review for a stand-alone evaluation compensation system for the NBSO, correct?

MR. MARSHALL: Yes.

Q.14 - And has the NBSO proceeded with that compensation review?

MR. MARSHALL: Not at this time.

Q.15 - Could you tell us what the current status or thinking is whether you are going to proceed with that compensation review or not?

MR. MARSHALL: It's currently in the budget to be done later this year.

Q.16 - So that the current thought process is that that review would be conducted in '08 or do you mean in the fiscal year sort of '08, '09?

MR. MARSHALL: It's in the budget to be completed in '08, '09.

Q.17 - Thank you. Now if we could go to exhibit A-4, and it may be useful to keep out both A-4 and A-6 which are the two sets of IRs. I'm going to be going back and forth between a couple of them. And in exhibit A-4, if we could look at the response to the EUB IR-2, Part 1. And what it is, you will see, is there is three fold-out pages. They are sort of longer than the page. They pull out a little bit. And if we could go to the third page in those pages. Again that's EUB IR-2, Part 1, the third page.
And just looking at the marginal note, it states that most employees are at the top of their salary range. Do you see that note? Can you explain why most of your employees are at the top of their salary range?

MR. MARSHALL: The majority of employees are union employees under secondment agreement with NB Power Transmission Corporation. And in all of the union agreements most of the jobs have a range of five or six steps in them, and most of the people in our organization have been there longer than that and have moved through that process so that they are at the top of the union classification for their job.

Q.18 - So essentially it's a question of seniority, time in their position?

MR. MARSHALL: Yes.

Q.19 - Thank you. Now I would like to ask a few questions around the issue of capital costs and leases. So if we could look at exhibit A-6 under -- which is the supplemental responses, and if we go to PI Supplemental IR-3(5). So again, that's exhibit A-6, response to PI Supplemental IR-3(5), which is on page 7 of the Public Intervenor tab.

And towards the bottom of that response you note with respect to the energy control centre a lease agreement is nearing completion and when it is executed the NBSO will provide a copy, correct?

MR. MARSHALL: Yes.

Q.20 - And has that lease yet been executed?

MR. MARSHALL: No.

Q.21 - Is there any contemplation of when that lease may be executed?

MR. MARSHALL: It's my understanding there are still some details to be worked out with that agreement, not least of which is final policy decision of government as to how the restructuring of the industry may proceed and what the relationship between NB Power and NBSO may be.

Q.22 - Considering the other hat you are currently wearing, I am loathe to follow up on that question, Mr. Marshall, but suffice it to say there is not a current lease document in place?

MR. MARSHALL: That's correct.

Q.23 - If --

MR. MARSHALL: Just -- there is not a current formal lease. The arrangement, it's pretty clear that the obligation is that NBSO pays for the costs of the control centre as booked by NB Power Transco which includes depreciation plus financing charges for interest and return on equity on that investment. That is the arrangement at this time.

Q.24 - Yes. And I will get to that shortly, Mr. Marshall. I was just talking about a formal lease document for now. Could you commit today, or could the NBSO commit today, that if, and I guess and/or when, a lease document is in place that it would be filed with the Board?

MR. MARSHALL: I believe that the response to IR-3 says when the agreement it completed it would be -- provide a copy and file with the Board.

Q.25 - Thank you. If we could go now to your response to NBEUB IR-32 -- and I'm sorry, this is in exhibit A-4, so your first set of responses. So exhibit A-4, EUB IR-3(2). And I believe that's on page 30 of that tab. And here you indicated that no cost benefit analysis has been carried out with respect to a potential NBSO purchase of the control centre, correct?

MR. MARSHALL: That's correct.

Q.26 - And I take it that that remains the case today?

MR. MARSHALL: That's correct.

Q.27 - Now if we could go to the supplemental IRs again, exhibit A-6, and if we could look at Integrys supplemental IR-12-A, and that's on page 44 under the Integrys tab. And here at the top of page 44 you show a lease payment estimate for the control centre building on one side and for control centre key dispatch on the other, correct?

MS. WEST: Yes, that is correct.

Q.28 - And the lease payment estimate for the control centre building shows an interest rate component of 9.32 percent, correct?

MS. WEST: That is correct.

Q.29 - And it shows for the building an amortization over 32 years, correct?

MS. WEST: That is correct.

Q.30 - And does that interest rate component of 9.32 percent and that amortization period -- is that built into the formula for the costs that you pay NB Transco for the use of the energy control centre?

MS. WEST: Yes, that is correct.

Q.31 - Thank you. And at page 49, which is the response to Integrys IR-12-B you stated, and I believe Mr. Marshall just said it a short while ago, that the NBSO pays its share of the amortization and finance charges for the building, correct?

MS. WEST: That is correct.

Q.32 - Now if we could stay in this same binder and turn to PI Supplemental IR-3, and if we could go to page 6 under the PI tab which is the response to 3(4)(c). And here you are talking about the new SCADA system scheduled for September 2009, and you state that Transco will own this and lease it to the NBSO and the NBSO will likewise pay the amortization and finance charges based on the total cost of the upgrade and Transco's weighted average cost of capital, correct?

MS. WEST: Yes, that's correct. That's the current arrangement.

Q.33 - That is also the current arrangement, is it?

MS. WEST: Yes, it is.

Q.34 - So is it fair to say then when we are looking at that interest rate of 9.32 -- is that reflective of Transco's weighted average cost of capital?

MS. WEST: I believe it is the current rate, and it is subject to change.

Q.35 - But that is it's current rate, correct?

MS. WEST: Yes.

Q.36 - Thank you. And is the SCADA upgrade still on target to be completed in September 2009?

MS. WEST: As far as I know, yes, it is.

Q.37 - And why does Transco need to own the SCADA system rather than the NBSO?

MR. MARSHALL: The SCADA system is an integral part of the energy control centre, to be able to operate and control the power system. So it's -- it has assets -- has component pieces that are out in the field as well as inside the control centre. And historically all of its costs have been booked as part of the control centre and all of those costs have been in schedule 1 in the tariff. And so under the current arrangement the costs would be financed and done the same way.

Q.38 - Yes, but does Transco -- just to see if I can get it clear -- does Transco actually need to own the SCADA system or could the NBSO own the SCADA system?

MR. MARSHALL: It's possible NBSO could own the SCADA system. It's not an essential requirement that one party or the other own it. What is essential is that there is a system and that it's operational and integrated with the transmission system and the operation.

Q.39 - And have you analyzed the cost of the NBSO owning the SCADA directly as opposed to being charged amortization and finance charges from Transco based on their weighted average cost of capital?

MR. MARSHALL: Not at this time, no.

Q.40 - Okay. I would like to turn briefly now to the issue of the Point Lepreau outage and just its impact on your application and rates. If we could go to exhibit again A-4, the initial IR responses. And if we can go to Public Intervenor IR-8(4), which I believe is at page 15 of the PI tab.

And here the NBSO notes that the Point Lepreau refurbishment puts downward pressure on rates for schedules 5 and 6, but that given the temporary nature of that downward pressure the NBSO has not adjusted the proposed rates to account for the impact of the Lepreau refurbishment. But your response goes on to state that under the Settlement Agreement payments by market participants would be lower during the Lepreau refurbishment due to the decreased need for reserves, correct?

MR. PORTER: That's correct.

Q.41 - And could you just explain for the benefit of the Board and Intervenors why under the Settlement Agreement payments by market participants would be lower during the Lepreau refurbishment due to the decreased need for reserves?

MR. PORTER: Yes. Under the Settlement Agreement the arrangement whereby we would charge for all of the capacity based ancillary services would be based on the actual expenses incurred. So in the case of ten minute reserves requirement, and actually for that matter the 30 minute reserve requirements, during the Lepreau refurbishment we no longer have Lepreau as the largest contingency, so the amount of reserve that we have to carry is reduced, so therefore the amount that we spend buying reserves is less, and therefore we flow lower costs through to transmission customers. Again that's under the proposed arrangement whereby our expenses for these services are flowed through to transmission customers.

Q.42 - So even though in this application you didn't adjust the schedule 5 and 6 rates, because of what you just explained the overall costs to the customers would be lower if the Settlement Agreement is approved, correct?

MR. PORTER: That is correct.

Q.43 - Thank you. I would like to briefly discuss --

MR. BARNETT: Mr. MacDougall, let me just --

Q.44 - Certainly.

MR. BARNETT: -- a question comes to mind on this point. Mr. Porter, what would the reserve requirement be reduced to from the -- with Lepreau out? I'm trying to get an idea of the magnitude of the difference between when Lepreau is operating and when Lepreau is not operating under this refurbishment circumstance.

MR. PORTER: Certainly. The ten minute spinning reserve requirements are based on the largest contingency which with Lepreau on line would be Lepreau at roughly 600 megawatts just leading into the refurbishment project. And then the 30 minute reserves are based on 50 percent of the second largest contingency which if it were on line -- if Lepreau were on line and Belledune were on line, Belledune would be the second largest contingency. With Lepreau off line that would shift Belledune into the number one spot as the largest contingency, with a contingency of 460 megawatts versus Lepreau's contingency size of approximately 600 megawatts. And -- sorry -- and then with respect to the 30 minute reserve requirements Belledune would no longer be the second largest contingency, it would be the first, and the second largest would, depending on the operation conditions at the time, it could very well be the Coleson Cove unit or perhaps some other source of generation.

MR. BARNETT: Thank you.

Q.45 - I would like to now discuss the topic of wind power briefly, again staying in exhibit A-4. If we could look at your response to GENCO, IR-19(e), which is at page 22 under the GENCO tab. And here you indicate that with respect to windpower forecasting costs, such forecasting is considered by the NBSO to be a reliability function and thus is to be covered under schedule 1. Why wouldn't it be just as appropriate, if not more appropriate, to directly assign these costs to windpower producers?

MR. PORTER: Firstly as you state already in the question, this is a reliability function. It's a service that we would undertake in order to give greater certainty to ourselves as to what the windpower production requirements would be. That's the same sort of thing that we do with respect to load forecast. These are two areas in which we anticipate a high degree of variability. And we do not want to be dependent upon others' forecasts, so we do that for ourselves, and we will dictate the standards for that service and procure those services. And as a reliability function we believe it to be appropriate that they be paid for by all system users.

Q.46 - But are these costs not being incurred because this is windpower, i.e., non-dispatchable power, and therefore causing you to incur extra costs on account of the nature of this generation?

MR. PORTER: Mr. Chairman, we do not differentiate between the different types of users of the system in that way. In terms of our load forecast, for example, some loads are more variable than others and more difficult to forecast. We don't carve out certain costs and try to charge them to certain loads versus others. We roll that into schedule 1 service which is the service that we provide. Similarly with respect to generators, no two generators really are identical. Each one has its own characteristics, be it with respect to how they are dispatched, how and when they arrange their outages, how predictable their output is. So again we treat -- we would perform those services relative to all generators and all loads and indeed with respect to wheel through transactions, and we take the total costs of providing those services and charge them out under schedule 1.

Q.47 - But you are today applying to the Board for another charge with respect to issues created specifically by wind generation, correct?

MR. PORTER: Yes, that is correct, but those are not costs that are incurred directly by us. Those are costs that are incurred directly by other market participants on the system, generators such as the Mactaquac generating station or perhaps Bayside Power who would be providing regulation and/or load following.

And it's only appropriate that those parties have their costs recouped. So we pay them for providing those services, and then that's a separate distinct cost say incurred by market participants, passed on to us and we choose to pass through -- we propose to pass those on through to the wind farms. That's different from the charges for load forecasting which is a service that we believe is key -- will be provided by us and is part of our running the business.

Q.48 - Thank you, Mr. Porter. If we could now move on, I would like to talk a bit about some of the issues around some of the clarification of tariff changes. And if we could go to exhibit A-14 which is the NBSO's responses to interrogatories on the clarification of tariff changes. And I don't believe this was put in a binder because it was a fairly small package of material. I only received it as a looseleaf grouping of pages, but it's entitled Responses to Interrogators on Clarification to Tariff changes, exhibit A-14.

And if we could go to Public Intervenor clarification IR-1(2), which is on page 3 of this package. And here there were some questions with respect to the process for annual proposal -- for the annual approval of the proposed revenue requirement, and you stated that the NBSO anticipates --

MR. PORTER: Excuse me. Which number again, Mr. MacDougall?

Q.49 - Sure. It's exhibit A-14, and it's Public Intervenor IR-1(2), and the response is on page 3 of the package.

MR. PORTER: Mr. Chairman, I believe that's on page 2.

Q.50 - I think the response is on page -- it's on page 3 in mine. Maybe they printed differently.

MR. PORTER: We have it. The response is on page 2. Yes.

Q.51 - Okay. I'm sorry, Mr. Chair. Maybe I won't use page numbers for this document, because obviously mine is --

CHAIRMAN: The version the Board is looking at it is on page 2, yes.

Q.52 - Okay. I will stick with the -- for this document I will stick with the responses. Obviously mine is paginated differently. So it is response IR-1(2), and here with respect to the process for annual approval of the proposed revenue requirement you state that the NBSO anticipates that the Board would permit interrogatories and the submission of comments by market participants. Correct?

MR. MARSHALL: Yes.

Q.53 - So the Board would ultimately be responsible with respect to the process for review and approval of your revenue requirement?

MR. MARSHALL: Yes, that's correct.

Q.54 - And market participants would have an opportunity to delve into that revenue requirement on an annual basis?

MR. MARSHALL: Subject to the Board process.

Q.55 - Thank you very much. If we could now go to PI clarification IR-6(2). And here you note that with respect to the $300,000 contingency that was provided for in the Settlement Agreement, that unexpected or unplanned costs are those which are not contemplated in the revenue requirement submitted to the EUB for approval, correct?

MS. WEST: Yes, that is correct.

Q.56 - And if any portion of the $300,000 was not used during any fiscal year, my understanding is that it would be rebated back to customers, correct?

MS. WEST: Yes, that is correct.

Q.57 - And for each annual revenue requirement when you came before the Board you would be showing the $300,000 contingency, correct?

A. Yes, that would be our plan.

Q.58 - Okay. If we could go to PI clarification, IR-7(1)(I) and here you note that the 2007/2008 surplus is solely attributable to surpluses on the sale of CBAS Services and I believe Mr. Kenny reiterated that in his opening statement today, correct?

MR. PORTER: Yes, that is correct.

Q.59 - And I would just like to follow up on that a bit. If we could go back now to exhibit A-4, and look at your response to EUB IR-10(1). And that should be on page 63 under the EUB tab. So that's EUB IR-10(1). And here we have a chart called surplus deficit by service, correct?

MS. WEST: Yes, that is correct.

Q.60 - And if we look at the last column, 2007/2008, it shows a capacity based ancillary service of surplus of $3,255,000, correct?

MS. WEST: That is correct.

Q.61 - And in fact also I believe, as Mr. Kenny might have reiterated this morning, it also shows a schedule 1 deficit of $462,000 and a schedule 2 deficit of $73,000, correct?

MS. WEST: Yes, that is correct.

Q.62 - So therefore what you are showing as a total surplus on the total line, after netting the schedule 1 and schedule 2 deficits from the CBAS surplus is a total of $2,720,000, correct?

MS. WEST: Yes, that is correct.

Q.63 - And my understanding is that it is that amount of 2.7 million dollars plus the $100,000 contribution from the NBSO retained surplus, which is to be rebated for '07/08 on account of the Settlement Agreement, correct?

MS. WEST: Yes, that is correct.

Q.64 - So in fact several hundred thousand dollars of the CBAS surplus in '07 and '08 has been utilized by the NBSO to reduce the deficit for schedule 1 and schedule 2 in '07 and '08 even with the Settlement Agreement, correct?

MR. MARSHALL: What was that quantity you said?

Q.65 - I said several hundred thousand dollars.

MR. MARSHALL: Several. I thought you said 700.

Q.66 - No.

MR. MARSHALL: Okay. Okay.

Q.67 - I didn't do all of the math. I take it it's about three or 400,000.

MR. MARSHALL: Yes, that's correct.

Q.68 - Thank you. And now if we could just stay in the same document but move back a column. Here there was a CBAS surplus of 1.92 million and a schedule 2 surplus of $10,000 and a schedule 1 deficit of $58,000, leading to a CBAS surplus for rebate of 1.872 million, correct?

MR. MARSHALL: Correct.

Q.69 - And if we go back to '05, '06 the majority of the surplus was again created by CBAS, correct?

MR. MARSHALL: Correct.

Q.70 - And there was a small overall deficit of $114,000 in the first year of operation '04, '05, correct?

MR. MARSHALL: Yes. That's the first half year.

Q.71 - First half year. Thank you. So is it fair to say that the CBAS surplus has increased significantly from a deficit in the first half year '04, '05 to a fairly significant surplus in '07, '08?

MR. MARSHALL: Yes.

Q.72 - And could you indicate for the Board and for the benefit of Intervenors today the amount of surplus that has accrued on behalf of CBAS for 2008, 2009 to date? So I guess the period April through September 2008.

MR. MARSHALL: Yes. Ms. West will dig that out because she does the forecasts.

MS. WEST: The forecast amount for this fiscal --

Q.73 - Well that would be fine. I was wondering if you had the --

MS. WEST: The actuals.

Q.74 - -- actuals to September and then the forecast to the end of the year. That was my second question, so --

MS. WEST: The year to date for CBAS surplus is a million-zero-fifty-five.

Q.75 - And your forecast for the fiscal year?
MS. WEST: Forecast for the fiscal year would be one-million-three-hundred-and-forty-nine.
Q.76 - Thank you. And if the settlement goes through this CBAS surplus that is continuing to accrue will stop accruing due to the mechanisms set out for clearances in the Settlement Agreement, correct, on a go forward basis?
MS. WEST: Yes, that is correct.
Q.77 - Thank you. And if we can go to EUB IR-11 which is page 65, you note at the end of your response that the most significant unanticipated surplus was a higher than budgeted surplus for CBAS, correct?
MR. PORTER: That's correct.
Q.78 - And I take it that still is the case, that has been your most significant unanticipated surplus?
MR. PORTER: Yes.
Q.79 - If we could turn now then back to exhibit A-14, the clarification questions, and if we could look at PI clarification IR-7(4). Here you note that if the Board approves the Settlement Agreement as proposed this will eliminated any accumulated surplus. Correct?
MR. PORTER: Yes, that is correct.
Q.80 - And my understanding is that this is because at the end of '08, '09 the Settlement Agreement provides a

methodology for clearance of any net surpluses?

MR. PORTER: Yes, that is correct.

Q.81 - But then once that surplus is cleared when you apply for your revenue requirement for 2009, 2010, as we discussed before, it will provide for a $300,000 contingency amount, as we discussed, right?

MR. PORTER: For schedule 1 revenue requirement that is correct.

Q.82 - Correct. Right. Now if we could -- I just want to briefly talk about one final area, and this is inter-tie benefits. And if we could go to exhibit A-4, and if we could look at GENCO IR-6, which is also on page 6. You are there, Mr. Porter?

MR. PORTER: Yes.

Q.83 - You indicate that you were aware that ISO New England was claiming 200 megawatts of tie benefits on the New Brunswick/New England interface to reduce capacity requirement in New England, correct?

MR. PORTER: Yes, that's correct.

Q.84 - And in GENCO's --

MR. MARSHALL: I would like to clarify on that.

Q.85 - Sure.

MR. MARSHALL: That's long-term forward capacity, not hourly short-term capacity.

Q.86 - Okay. In GENCO 6(c) where you were asked whether you considered a similar arrangement where tie benefits can be claimed from ISO New England to benefit load and reduce costs in the control area, you stated that that you considered a similar claim of benefits with respect to the New England tie, but chose not to accept the associated risk to reliability, correct?

MR. PORTER: That is correct.

Q.87 - And can you tell me what the tie benefit ISO New England is now claiming is? Is it still the 200 megawattts, or is it a different figure? I think there may be reference in it in GENCO's supplemental IR-2. There was a revision --

MR. MARSHALL: Yes.

Q.88 - There was a revision made this morning. I apologize for interrupting.

MR. MARSHALL: Yes. There was a correction made earlier in GENCO's supplemental in GENCO's supplemental IR-2. We had that they were assuming 316 megawatts of tie benefits, and that was corrected to 360.

Q.89 - And at the bottom of that page you also say we have assumed that 716 megawatts of tie benefits would be available from New Brunswick?

MR. MARSHALL: Yes, that's what it says. And it's important to understand that that's not what we assume. That is the information we got from New England and what they said they assumed.

Q.90 - Correct. But their claim is they are assuming 200 megawatts of tie benefits for years prior to the start of the forward capacity market and then up to 360 from 2010, 2011, correct?

MR. MARSHALL: That's correct.

Q.91 - And then for the years 2011, 2012 they have assumed 716 megawatts?

MR. MARSHALL: That's the information we got from them, yes.

Q.92 - That's their statement of what they are doing in claiming tie benefits from New Brunswick?

MR. MARSHALL: Yes, that's correct. That's a direct quote from ISO New England.

Q.93 - Okay. And the NBSO isn't claiming any tie benefits from the ISO New England currently, correct?

MR. MARSHALL: Actually that's not quite true. NBSO -- first of all, it's important for the Board to understand that these tie benefits are long-term forward capacity. And in the Maritimes area the traditional criteria has been 20 percent of peak reserve as a capacity requirement long-term.

In doing that, studies are done, adequacy reviews are done every three years on a major study and updated on an annual basis, and submitted to Northeast Power Co-ordinating Council, you know, for approval. To demonstrate to them, because now with mandatory reliability requirements there is mandatory obligation that we demonstrate that the Maritime area meets the NPCC criteria of one day of loss of load probability. In terms of doing that, in previous submissions that we have made when Point Lepreau was scheduled to be out of service there were years during the Point Lepreau out-of-service that there was a need to rely on inter-tie benefits to demonstrate you had that capability of one day in ten years. So New Brunswick jointly with Nova Scotia conducts those studies and today New Brunswick System Operator as the reliability co-ordinator co-ordinates that and submits the studies for the Maritimes. And in doing that there are times that a tie benefit is considered in order to meet the one day in ten years capability. But that it's not -- there is not a prescribed number that's allocated ahead of time in doing those studies.

Q.94 - But just let me get it clear here, Mr. Marshall. If you look at the response again in GENCO supplemental IR-2(B), the ISO New England does the same form of probabilistic system simulations for a one day in ten years loss of load expectation, correct?

MR. MARSHALL: Yes.

Q.95 - Yet they are claiming these tie benefits for long term capacity, correct, for New Brunswick?

MR. MARSHALL: Yes.

Q.96 - And you are not? I mean I'm just going through your response, GENCO IR-6(C) where you say, NBSO considered a similar claim of benefits but chose not to accept the associated risk, and I will get into that momentarily.

MR. MARSHALL: The point is it currently or not considering it in terms of changing the criteria that is in the marketplace for the maritimes whereas New England essentially meet NPCC criteria and rely on inter-tie benefits in order to meet their criteria. That is not the situation in the Maritimes.

Q.97 - Correct. You are not relying on any inter-tie benefit.

MR. MARSHALL: No,I didn't say that. I said there are times we do rely on inter-tie benefits. Certainly during the period that Lepreau was scheduled to be out of service this coming winter when the studies were done two and three years ago we show a reliance on inter-tie benefits in order to meet the forecast load for this coming winter. So there are times that we have utilized tie benefits to meet the criteria. But there has been no -- there has been no change in the concept that the long-term reliability criteria for the Maritimes should be changed from a 20 percent reserve margin now. That possibly could be reviewed in the future and looked at in saying with the second tie in place, with more capability in place, maybe that reserve criteria could be relaxed, but at this point in time it hasn't been and there aren't studies at this time to change it.

Q.98 - Okay. Mr. Marshall, when you say you have used it at times, for example with respect to the Lepreau outage, how does the market or who in the market gets the benefit of that claim for inter-tie capacity?

MR. MARSHALL: The parties that would get the benefit out of that in the overall market place would be end use customers in that it would lower overall long-term reliability costs.

It's important for the Board to understand that this is a long-term reliability criteria of what you need looking long-term. Operationally the New Brunswick market rules are very clear in that the amount of capacity that has to be real solid capacity in the ground demonstrated to the system operator prior to going into the winter period, the capability period, all right, has to meet the reserve requirements forecast for that coming winter. And on that basis we do not rely on any other capacity other than as stated in the response, IR-6(c) GENCO, down at the bottom, we do rely on and have the provision for the 100 megawatts of operating reserve credits across NPCC, that value is used to reduce the requirement in the market place so that it reduces the overall cost to market participants and end use customers.

Q.99 - With respect to the Lepreau outage and the calculation you carried out, could you provide an undertaking which shows the amount of inter-tie capacity that you considered in determining what was required during the Lepreau outage and how that reduced costs to customers?

MR. MARSHALL: We have no analysis of how it reduced cost to customers. As far as the actual study showing what the reliance on the inter-tie may or may not have been year over year, those documents are available through NPCC. They are filed annually and we could undertake to get them.

Q.100 - I guess I would like it if the undertaking, rather than just filing the documents, could be a little more precise to indicate what amount of inter-tie benefit you took account of in determining how New Brunswick was going to deal with the situation when Lepreau was down, and then provide what comments you may on how that would have flown through to the benefit of customers, since in my earlier response you said that it would have flown through to the benefit of customers?

MR. MARSHALL: We deal with reliability. So the analysis is done. What are the megawatts of capacity required in order to meet the criteria? That's what we deal with. The value of that capacity, if it lowers the requirement presumably then it lowers the cost. We do not have the costs of the voided capacity requirements. Those flow back to market participants in the market place. So it's not our job to calculate the benefits to each individual market participant. It's our job to deal with the reliability requirements for the system. We can provide you the megawatts of reliance on the system. Somebody else is going to have to calculate the value.

Q.101 - Okay. Could you undertake to do that, Mr. Marshall?

MR. MARSHALL: Yes.

CHAIRMAN: If I could just clarify precisely -- maybe we could restate precisely what it is that has been undertaken, but just as importantly, when would that undertaking be provided? I'm just wondering is that something that done very quickly or -- I don't really want to get into an undertaking that we are going to get the answer to several days later.

MR. MACDOUGALL: I understand, Mr. Chair.

MR. MARSHALL: My understanding, Mr. Chairman, of the question and what we would provide is the long-term tri-annual review adequacy reports that we file with NPCC for the Maritimes area that would show how many megawatts of inter-tie benefits may have been utilized over the last few years from those studies? That's my understanding of what we are being asked to provide.

MR. MACDOUGALL: And, Mr. Chair, all we would require is the single excerpt or page or paragraph, if it can be done to that, or if the reports are being provided that there be an indication where in the reports. Just that small bit of information.

CHAIRMAN: Sure. And how long would it take to provide that information, Mr. Marshall?

MR. MARSHALL: We should be able to have that this afternoon.

CHAIRMAN: Thank you.

Q.102 - Just sticking with this line of question but hopefully we won't get back into the exact same discussion we have just had. There are now two tie lines between New Brunswick and Southern Maine, correct, the MEPCO line and the new International tie-line, correct?

MR. PORTER: Yes, that is correct.

Q.103 - And together these allow for a thousand megawatts of transfer capability, correct?

MR. PORTER: Yes, that is correct.

Q.104 - And these lines --

MR. PORTER: Just some clarification there. The physical capability for a thousand megawatts of flow from New Brunswick to New England has been there since December 5th of last year when the second line went into service. Just for the record, there has been a bit of an issue with respect to regulatory aspects in the U.S., where they had a bit of an issue as to how that -- how the original line would be treated relative to the new line, and to -- until they could get that issue resolved the regulator in the States chose to maintain the prior numbers for transcapability which was the 700 megawatts. But that issue has now been resolved and the number will go to the thousand megawatts from the 700 effective December 1st of this year.

Q.105 - And my understanding is together these two lines, because now there is two lines instead of what used to be a single redundant line, now provide for a 300 or more megawatts of firm import capacity from the New England pool into New Brunswick?

MR. MARSHALL: Yes. It provides 300 megawatts firm coming

north and up to 550 megawatts firm plus non-firm.
Q.106 - Yes. So there is 200-plus contingent or conditional firm along with the 300 or 350 firm, correct?
MR. MARSHALL: That's Correct.
Q.107 - Thank you. Which wasn't the case --
MR. MARSHALL: Effective December 1st this year.
Q.108 - Yes. And before that when there was only one line there was no firm, correct? There may have been some contingent or conditional firm but there was no firm?
MR. MARSHALL: There was 100 megawatts of contingent firm north on MEPCO out of New England.
Q.109 - Of contingent firm. But now there is 350 megawatts of actual firm and 200 megawatts of contingent firm, correct?
MR. MARSHALL: That's correct. But actually it was more than 100 . There was 100 -- in New England there was 100 megawatts of firm. There were some conditions tied to it but there was 100 megawatts of firm transmission under the tariff and an additional 180 megawatts of non-firm. So the maximum south to north was 280 megawatts subject to the operating conditions in New England. With the two lines in place that 280 goes to 550.
Q.110 - And 350 is actually firm.
MR. MARSHALL: 300 is actually firm.
Q.111 - Sorry. Correct. Thank you.

CHAIRMAN: Mr. MacDougall, we are thinking about a morning break. Would this be a good time for that, or do you have just a couple more questions?

MR. MACDOUGALL: In fact, Mr. Chair, my questions are over, so it's a perfect time. And it was a pleasure to once more deal with Mr. Marshall, even though it was in his retirement. So it might be the last time we have a discussion this way, so I want to thank him again for the back and forth.

MR. MARSHALL: You are welcome, Mr. MacDougall.

CHAIRMAN: Thank you, Mr. MacDougall. We will take a 20 minute break and when we come back, Mr. Morrison, it will be your turn for questions.

(RECESS - 11:00 a.m. - 11:20 a.m.)

CHAIRMAN: Mr. Morrison, any time you are ready to proceed.

<u>CROSS-EXAMINATION BY MR. MORRISON</u>:

Q.112 - Thank you, Mr. Chairman. Good morning, Panel. I will be dealing primarily with just two exhibits, exhibit A-1 and exhibit A-5. So if you want to take those out and keep them handy.

And I will direct my questions to whomever on the Panel wants to answer it.

I want to deal -- I'm going to be dealing almost exclusively with schedule 3. As I understand it, schedule

3 has three schedules, schedule A, schedule B and schedule -- subschedule C. And schedule A is the automatic generation control or AGC, correct, Mr. Porter?

MR. PORTER: Yes, that is correct.

Q.113 - And schedule B is load following, correct?

MR. PORTER: Yes, that is correct.

Q.114 - And schedule C is a combination of AGC and load following for wind generators, is that a fair characterization?

MR. PORTER: Yes, it is.

Q.115 - And schedules 3(a) and (b), they are calculated on the basis of megawatts, correct?

MR. PORTER: Yes, that is correct.

Q.116 - And am I correct in my assumption that schedule 3(c) is calculated based on megawatt hours and not megawatts?

MR. PORTER: Yes, that's correct. I just want to elaborate just to be clear. The billing determinate -- so the metric which would be used to calculate the charge with respect to 3(c) is megawatt hours.

Q.117 - Thank you. And they are completely -- they are different measurements, aren't they, megawatts and megawatt hours? They aren't the same metric for measuring, correct?

MR. PORTER: Yes, that is correct.

Q.118 - And I understand, Mr. Porter, that the AGC and load following charges in schedules A and B, they are paid -- essentially that's a charge on the load or the customer, correct?

MR. PORTER: Yes. Schedules A and B represent obligations on load serving entities to either buy those services or self-supply them.

Q.119 - But it's a charge on the load, and as I understand it schedule C is different in that it's not a charge on the load but would be a charge on the wind generator, correct?

MR. PORTER: Yes, that is correct.

Q.120 - And you alluded to it, Mr. Porter, in both 3(a) and 3(b), as it currently stands the customer can choose to self-supply up to 90 percent, correct?

MR. PORTER: Yes, that is correct.

Q.121 - And I just want to turn to exhibit A-1, and it's under the tab -- it's after tab 4 and it's sub-tab rates, direct evidence regarding changes to the tariff. Do you have that in front of you, Mr. Porter?

MR. PORTER: Yes, I do.

Q.122 - If you could turn to page 16, and I'm going to read from lines 17 to 19, and it says in your evidence that those having an obligation with respect to the service will have the option of self-supplying rather than purchasing through the tariff as is the case for loads having ancillary services obligations.

Do I take from that, Mr. Porter, that rather than pay the rate in schedule 3(c) that a wind generator can self-supply his AGC on load following?

MR. PORTER: Yes, that is correct.

Q.123 - And is there or is there contemplated to be any limit on that self-supply?

MR. PORTER: We have not proposed -- no, we have not proposed any limitation on the portion which is self-supply.

Q.124 - Okay. I'm going to put a couple of scenarios to you and ask you to comment on them. Assume that DISCO has a wind generator as part of its network resources. DISCO chooses to self-supply 90 percent of its AGC and load following and will purchase the additional ten percent from the SO. Will the rate that DISCO must pay or the rate that will be paid -- is it going to be based on schedules A and B or will the rate in schedule 3(c) apply? If a wind generator in DISCO's fleet of network resources, DISCO is going to self-supply, which rate does it pay, the schedule A and B rate or the schedule C rate?

MR. PORTER: As I understand it in your scenario, distribution is both a load serving entity with an obligation pertaining to its load, and a party with a contract for the output of a wind farm. And so in that scenario there would be an obligation both with respect to the load and the wind farm.

So certainly distribution -- DISCO would pay for the load serving obligation portion for which they did not self-supply, and in the case of the wind farm the obligation is really with the market participant for that wind farm. So it depends on your scenario whether DISCO is the market participant or another market participant, but there would be -- with respect to the wind farm there would be an obligation to either self-supply or purchase those services under schedule 3(C).

Q.125 - So in that case even though this is a wind generator that's under contract to DISCO, the wind generator would still pay the schedule 3(C) rate, is that correct?

MR. PORTER: Or there had to be a self-supply in lieu of the payments. The obligation with respect to load serving -- to loads is separate and distinct from the 3(C) which is with respect to wind farm generators.

Q.126 - Okay. I'm going to put another scenario to you. Assume that you have an independent wind generator that's not part of DISCO's network resources. It decides to self-supply its AGC and load following up to 90 percent, let's say, and presumably it purchases those services from GENCO or some other generator. It will then be in a position of having to purchase the balance of the ten percent of AGC and load following from the SO, correct?

MR. PORTER: Yes, that's correct.

Q.127 - In that case am I correct in assuming that it would then pay the SO the schedule 3(C) rate?

MR. PORTER: Yes, that is correct.

Q.128 - And the last scenario I am going to put to you, Mr. Porter -- I'm not trying to set a trap here in any way. This really is an issue for my client in terms of who pays. My last scenario is assume an independent wind generator that chooses not to self-supply and will purchase all of its AGC and load following from you guys, from the SO. And I assume that in that case schedule 3(C) would also apply? They would pay the schedule 3(C) rate?

MR. PORTER: Yes, that is correct.

Q.129 - So in all the scenarios I have put to you I believe your answer is that as far as the wind generator is concerned it will always pay the schedule 3(c) rate?

MR. PORTER: To the extent that it is not self-supplying its pro rata share of the obligation, that is correct.

Q.130 - I want to turn now to exhibit A-5. And it's under the tab schedule (C), the black inked schedule -- sorry --

schedule 3 tab. Do you have that?

MR. PORTER: Yes, I have that.

Q.131 - Could you turn to page 94, which I believe is the last page in that tab. And on that page it says, this service does not apply to generators that are exporting from the balancing area and for which dynamic scheduling occurs whereby the delivery to an adjacent balancing area is equivalent to the generator's production.

First, what do you mean by dynamic scheduling?

MR. PORTER: Dynamic scheduling would be -- I guess before I explain dynamic scheduling it might be best to explain how we do scheduling currently. And this is scheduling between say our balancing area, and balancing area is New Brunswick, Prince Edward Island and Northern Maine. And transactions between our balancing areas and other balancing areas are done in hourly increments. So if a participant here in New Brunswick wanted to export 100 megawatts to Quebec, they would submit to us a schedule for the hour to say 100 megawatts and repeat that -- they would have a schedule in place for each applicable hour. And that's the standard way we do business now.

In the case of dynamic scheduling we would allow such commercial transactions to have their schedule modified basically in real time, so that if it were a 50 megawatt wind farm which produces 50 megawatts at one point in time, 50 megawatts would flow through to the external markets such as let's say New England. Let's say the full output of the wind farm was scheduled to be delivered to New England. As the wind speed increased and the production increased from 50 up to say 55 or 60, the commercial transaction schedule and thus the actual flow to the New England market from New Brunswick would be increased accordingly.

Q.132 - So by dynamic scheduling you just mean that it's sort of hour by hour, even minute by minute adjustment to the schedule?

MR. PORTER: Minute by minute, yes. Real time. And perhaps maybe even down into seconds. You know, for all intents and purposes, the full output of that facility would have been transferred, you know, minute by minute or even second by second to that external market. And the significance of that is that this variability and forecast error that otherwise would be a burden on the system here, on this balancing area, you know, would cause us to adjust other resources to compensate, would not need to be -- those costs would not be incurred because the variability and forecast error would be transferred to the external market.

Q.133 - And that's what I want to get into a little bit, because it says this service does not apply basically to a wind generator that's selling all of its production to a customer outside of the balancing area. So I'm going to put this scenario to you. Assume that you have a wind generator here in New Brunswick and it's selling it's entire production to a customer in Maine. Does the wording that I just referred to -- does that mean that that wind generator does not have to acquire any AGC or load following from the SO? Like you wouldn't be providing -- it would not have to buy AGC and load following from the SO in that circumstance?

MR. PORTER: That is correct.

Q.134 - And in that case would -- and again we are dealing with a Maine customer -- would that Maine customer be required to obtain any AGC or load following from the Maine system operator or NMISA?

MR. PORTER: That's entirely dependent on what rules would apply in that market.

Q.135 - Okay. So is it the reason that the wind generator wouldn't have to acquire any AGC and load following from the SO, is that because it's selling its entire production at the other end of the pipe?

MR. PORTER: Yes. Yes, that is correct.

Q.136 - Is there a situation where -- given that same scenario where the wind generator would have to purchase AGC or load following?

MR. PORTER: There are a couple of scenarios. One that I certainly -- I don't know whether you are heading to this or not, but a wind generator that was -- commercially was exporting part of its output but delivering part of its output within a load served (inaudible) by this balancing area, and if that were the case then we would have to have a differentiation between what portion of the output was being exported and what portion was being used to serve load locally, and the two portions would each had to be treated in accordance with the respective rules. So if for -- say for an example, if they say 50 percent of output was to be dynamically scheduled to New England, for export to New England, then the schedule 3(C) rate would not be applied to that 50 percent of the output.

Q.137 - And the balance of the 50 percent you would have to supply -- assuming they are not self-supplying, the SO would have to supply the AGC and load following and charge the schedule 3(C) rate, correct?

MR. PORTER: That's correct.

Q.138 - Okay. Again --

MR. PORTER: Sorry, Mr. Morrison. I just would add, Mr.

Chairman, that you asked if there are any scenarios. The other scenario I just would want to mention at this point is that there is always the possibility the dynamic scheduling could not be provided. And I mean there might be certain hours -- for example, if we had the case where the interface between our market and the New England market was fully scheduled, and then the wind farm that was trying to dynamically schedule increased its output, we might have hit a limit whereby for that hour or few hours we could not modify that schedule so that all the output was exported. That's not necessarily something that would happen frequently, but that is a scenario under which there might be a caveat there about the ability of that customer to self -- through that dynamic schedule.

Q.139 - So just to be clear, Mr. Porter, in cases where for whatever reason dynamic scheduling is not possible, then in that case the wind generator would be required to provide -- to purchase, again assume no self-supply, would be required to purchase the AGC and load following from the SO at the scheduled 3(C) rate, correct?

A. Yes, that is correct.

Q.140 - Okay. And I don't want to beat this scenario to death, but again we have the wind generator in New Brunswick selling production to a customer in Maine. What if the Maine customer wanted to purchase AGC and load following from the SO, could it do it?

MR. PORTER: Under the tariff we certainly would provide that to any load serving entity that is within the balancing area. So your question was with respect to Maine. It would be -- that would be the case with respect to Northern Maine because they are within the balancing area. We do not offer those services to load serving entities outside of our balancing area.

Q.141 - So it would only apply to that part of Maine that is within the Maritime control area, or the balancing area?

MR. PORTER: Yes, that is correct.

Q.142 - And in that case again the schedule 3(C) rate would apply for the load following -- or because then you have -- the reason I raise it is you have -- in this case it's not the wind generator that's asking for the ancillary service, the load following, it's the customer. And so would it pay the schedule A and B rate or would it pay the schedule C rates?

MR. PORTER: Again, you have to think separately about the generator versus the load serving entity, and for the focus on the wind farm, if the wind farm is physically located within the balancing area, then the market -- what we would want to see is that the market participant with respect to that generation facility has this obligation. So -- and we don't get into this issue whether they are serving load in Northern Maine or New Brunswick. And the issue about 3(A) or 3(B) applying is not applicable, it would be 3(C) that would apply because it's the case of a wind farm.

Q.143 - Okay. And that's ultimately the point I was trying to get to, Mr. Porter, is that we would like to have some assurance that if load following and AGC is required as a result of wind generation then it's the schedule 3(C) rate that will apply in virtually every circumstance, and I think that's what you are telling me?

MR. PORTER: Yes, that's correct. The fact that a party might be purchasing under 3(A) and 3(B) in no way reduces their obligation, the obligation relative to wind farms under 3(C).

Q.144 - Now I'm going to stick with you, Mr. Porter, but anybody can answer the question. Again I'm going back to exhibit A-1, and it's under the purple tab 5, appendix D, which is the wind integration study.

MR. PORTER: Yes, we have that.

Q.145 - And if you could turn to page 13, specifically table 7.

MR. PORTER: Sorry. The page number again?

Q.146 - Page 13. And I'm looking at table 7, Mr. Porter, and looking at -- well if you go down to -- one, two, three, four -- fourth line down, it says -- sorry, fifth -- no -- fourth line down -- regulation unit commitment and dispatch, and there are a number of question marks that go across that table, do you see that?

MR. PORTER: Yes, I do.

Q.147 - And my question to you is the schedule 3(C) rate, does it include any recovery of costs associated with additional regulation unit commitment?

MR. PORTER: No, it does not.

Q.148 - And why not?

MR. PORTER: The modelling that was performed in the course of this Maritimes area wind integration study was dealing with data on hourly resolution, the wind speed, wind production data that we had and that was simulated, was based on hourly production. The load data was based on hourly production. And therefore we were not able to capture -- regulation was something -- is a service that is provided on a minute by minute basis, so we were not able to capture or simulate that requirement and capture that in the model.

Q.149 - Since this was done have you done any further analysis to determine what that unit commitment and dispatch cost would be?

MR. PORTER: No, we have not. We are still in the same situation where the data that we have and the modelling that we perform is on hourly resolution.

Q.150 - But you would agree that it is a real cost nonetheless. It's just that you at this point can't model it, is that fair?

MR. PORTER: Theoretically the cost would be there. The regulation burden tends to be relatively small compared to the load following. But I can't honestly say what -- I can't quantify it. So it is still an unknown.

Q.151 - I'm going to ask you a fairly general question, Mr. Porter, and just to put it in context, GENCO, it is the largest generator in the system. And I don't think this will come as any surprise to anybody who was at any of the technical conferences, but GENCO does have concerns that as the largest generator in the system that it will end up back-stopping the system, particulary with respect to wind, if it is not fully and fairly compensated for its costs. Has the SO done any analysis to ensure that GENCO will be fairly compensated for the schedule 3 services?

MR. PORTER: We believe that this Maritimes area wind integration study is, you know, a detailed analysis, you know, subject to the limitation I just spoke of, but believe it to be a very appropriate measure or estimation of what the cost impacts would be, certainly the best information we have at this time. And we would like to think a little bit more about that issue about the regulation, it being a relatively small component. Without looking it up we believe that the studies performed elsewhere tend to indicate that regulation is a relatively small component of the cost, and intuitively that makes sense.

If you think about wind power production and whether the production is increasing or decreasing minute by minute within the hour, and that's the way the regulation burden is placed. And I say intuitive. If you think -- it's hard to think that when the wind happens picks up over the next few minutes here in Saint John that it would necessarily be picking up in the short-term basis in Caraquet as well.

If you want to look at load following, as a storm front comes through there might be a higher correlation between increases or decreases across the province, but much less so. I think it's more likely that in terms of the minute to minute variations that they maybe tend to cancel each other out.

So that is putting some explanation around the notion that those quantities for regulation are relatively small.

Now with respect to your question about whether the -- you know -- more analysis is required, we have indicated in response to interrogatories that we will be tracking on an ongoing basis, you know, subject to approval of this Board, to put into place this mechanism we will have the systems in place and the tracking to measure those costs on a go forward basis. And as we have indicated in the proposal is that we would not allow the level of windpower development to get to the point where we were having those costs shift onto other parties. The rate, the dollar per megawatt rate that we propose to charge to wind farms under schedule 3(C) is intended to cover off those costs. And so as we track on an ongoing basis what the costs are we will monitor to make sure that we are collecting enough money to cover off those costs that are incurred and to pay those suppliers such as NB Power Generation that are providing those services.

Q.152 - That kind of raises -- goes into my next question. If you turn back to page 5 on that same document, the wind study, and if you look at table 1, it shows projected by 2016 potentially 1,522 megawatts of wind development, is that correct?

MR. PORTER: Yes, it is.

Q.153 - And by my calculation it looks like 74 percent of that will come from outside of this -- it's projected that it may come from outside New Brunswick, is that correct?

MR. PORTER: Agreed, subject to check.

Q.154 - So the SO potentially will be responsible for providing AGC and load following services for a fairly significant level of wind generation, correct?

MR. PORTER: Sorry. Mr. Chairman, back to that last question. The 75 percent may be true with respect to the entire Maritimes area. Just to differentiate within that table, the total area that is referring to the Maritimes area which includes Nova Scotia, the balancing area, of which we are part, does not include Nova Scotia. So I mean, I think we are all capable of running those percentages to see how much is -- what portion within the balancing area versus what portion within the Maritimes area is outside of New Brunswick.

Q.155 - Okay. I don't think anything turns on it, but thank you. I guess the point I'm trying to make is you have got significant wind generation projected to come on line by 2016, and I assume that the SO will be responsible for providing AGC and load following services for a significant amount of wind generation by 2016, correct?

MR. PORTER: That's a possibility that we would have no way of knowing which market participants were either dynamic schedule for export or self-supply for those services, but there will be an obligation with respect to a significant quantity of wind power production in the area.

Q.156 - And I know that this wind project summary report has been prepared, but has the SO undertaken any additional studies or analysis to ensure that it can meet what could potentially be significant obligation with respect to AGC and load following for these wind projects by 2016? Is there any ongoing studies or analysis that you have undertaken?

MR. PORTER: A couple of things. One is that -- not that we have made that particular study. We stand by the notion that in and around 400 megawatts for the balancing area, we expect to be reaching a threshold which is in our proposal at which the cost would be about a dollar per megawatt hour.

And what we have said in our proposal is that when we go beyond that we would -- for additional development of wind power in the balancing area we would require self supply. Because we do not want to be in that situation where we have set ourselves up with an obligation to provide these services but having no means to procure those services. So that's the intent.

But I do want to say that -- that's the first part of the answer. But the other part of the answer is that we also recognize that there will be significant development of wind power potential in the region. And we have an obligation to do what we can to address these types of issues.

And to that end we are working with folks at ISO New England, Trans Energie in Quebec, Nova Scotia Power on a host of -- on a broad range of activities and changes in how we operate that could mitigate these costs and therefore allow us to put more wind power in the area at the same cost or maybe put the same amount of wind power on the system at lower cost. And I give some examples. But one would be the dynamic scheduling which we have already spoken of. Certainly if all the wind farms that are exporting outside of the balancing area were fully dynamically scheduled, we would not have that cost-shifting issue at all on those wind farms.

We are also working with ISO New England to make arrangements to move away from what we have talked about or should we schedule now on hourly increments. We are starting a pilot almost as we speak, to be able to change schedules every half-hour rather than just once an hour. So twice as many opportunities to make adjustments to those schedules for flows between New Brunswick and New England. We want to pursue the same types of discussions with Trans Energie in Quebec and Nova Scotia Power.

We know that by more accurately forecasting we can somewhat reduce the costs that would be incurred in integrating wind. So we are -- as we have in here a proposal to undertake wind power forecasting, we have discussions with Nova Scotia Power and ISO New England and Wind Forecasting Services to try and determine the best arrangement for us to do that wind power forecasting. And with better forecast, as I said, we can reduce the cost impacts on the system.

We certainly are working with the Northeast International Committee on Energy which has representatives from each of the eastern Canadian provinces and New England states.

And they have regulatory representatives, government representatives.

And have impressed upon them the importance of the region cooperating on these types of efforts to allow wind power and other nondispatchable variable resources, which are typically -- many of which are renewable -- to be integrated onto the system more efficiently.

So on one hand we are putting this charge in place to protect the interests of those parties that are providing the services of regulation and load following. But on the other hand we are aggressively pursuing improvements in how we operate both the markets and the system that will tend to lessen that cost impact.

Q.157 - I want to follow up, Mr. Porter, with something you referred to. That is with respect to this one dollar charge by April 2012.

If you go back to exhibit A-5, again under the same tab, the black schedule 3 tab?

MR. PORTER: Yes. We have that.

Q.158 - And if you look at page 93 it says "To the extent that expenses are expected to exceed the revenues for these services, new nondispatchable wind generation in the balancing area shall self-supply the service in accordance with the market rules."

This statement seems to contemplate -- and maybe you have explained it a little bit already -- but it seems to contemplate that by April of 2012 the dollar may not be sufficient to cover costs.

Is that a fair statement on my part?

MR. PORTER: Yes. That's correct.

Q.159 - Okay.

MR. PORTER: All of the costs in the system. I guess I want to be clear by what we have said here in this proposal, is that we would not -- we would not take on those costs. The dollar per megawatt hour acts as a threshold as the wind power development increases. And at the same time we will be making changes to try and reduce the costs.

But when we get to that crossover where -- or we are approaching the crossover where it looks as though the costs that flow through us are approaching that dollar per megawatt hour of wind power production, then we would have to say you know what, we have really reached the point where we can no longer assume that we can procure the relevant services and would thereafter require new market participants to self-supply their pro rata share of the obligation.

Q.160 - So when you hit this threshold, whatever number of megawatts that is you are estimating to be, 400 -- but whatever it is, once you reach that threshold, then what you are saying is to new wind generators is, we are not going to supply the AGC and load following, you have got to self-supply it.

Is that basically what you are saying?

MR. PORTER: That or dynamically schedule, yes, that is correct.

Q.161 - Okay. What happens if the new wind generator just can't self-supply? He can't buy it from GENCO or some other generator and there is no other third party contract that he can access to supply the AGC and load following. What happens to him?

MR. PORTER: That would be an issue that would need to be resolved before that wind farm went into service. We would be looking out far enough in advance to give that kind of notice.

And before any connection agreement would be signed and market participation and accreditation provided, et cetera, that would need to be worked out. And I don't know that there are any other options. But it would be up to the market participant to find any option.

Q.162 - And I'm not here to carry the can for the wind generator as such. But it does strike me as being somewhat discriminatory in that existing wind generators can purchase the ancillary service, the AGC and load following. The new wind generator is basically saying, you have got to self-supply. And maybe that is just a reality.

But am I correct in that is what this says?

MR. PORTER: That is what it says. And there is a reason for that. We had to make a policy type decision. And the other possible scenario would be to say okay, whatever the costs incurred are, that's what we will pass through to the wind farms.

But that puts a substantial risk on the early developers that might go in with a certain business case. That today they can -- under our proposal they could say okay, I know I'm going to incur an extra dollar per megawatt hour charge.

But under the scenario in which we just would keep updating that rate based on cost, if hundreds and hundreds and hundreds of megawatts of wind farm facilities added onto the system, the proponent that had a good business case in 2008 may find him or herself in 2012 with a losing business case.

And given that regulatory uncertainty we consciously chose to go for the greater certainty, to put a rate out there which is known that those proponents, you know, this proposal is accepted, would have a much greater level of certainty as to what their costs would be.

A concern would be that if you went to the other approach, where just whatever the costs incurred are, has more (inaudible) added onto the system, that it might actually scare some proponents off. And you might never get to the large numbers. But you might not even get to the small numbers. So it's to tackle the regulatory uncertainty issue.

Q.163 - Thank you, Mr. Porter. I would like to explore a little bit about the operation of these accounts, how they are going to work. But perhaps I will wait a moment.

MR. PORTER: Sorry. Mr. Chairman, I could just expand on the previous discussion.

CHAIRMAN: Sure.

MR. PORTER: The notion of differentiating between those that are first on the system versus later, it is not without precedent. Certainly we do have the case where a generator wants to connect to the system today. And we have this issue about who can use the existing transmission capacity.

And you can certainly have a situation today where someone comes along and wants to connect. There happens to be surplus capacity. It makes it fairly straightforward to that generator to connect to the system, no extra costs incurred and no major extra costs.

But it might be that the next generator comes along after that, we do our analysis and say gee, you know, they want to connect to the same location, but gee there is no surplus capacity there now, it has been used up. That last party in making the request to connect to the system would incur the cost of upgrading the system.

So I just wanted to make the point that our regulatory regime here is not without precedent with respect to having differentiation between first in and last in.

Q.164 - I appreciate that. I would like to talk a little bit about how these three schedules, A, B and C of schedule 3, how the accounts are going to work. And I guess I'm coming at this from of course the debate or discussion we have been having about surpluses and deficits in the CBAS account generally.

But under schedule 3(C), assume it is 2012, and the wind generator will pay a dollar for these services to you. And I assume then that you will use this money to purchase those services.

You will collect a dollar from the wind generator. You will have to go out and purchase AGC and load following. So you will pay that dollar out to a generator, presumably GENCO or some other generator, correct? That is generally how it is supposed to work?

MR. PORTER: Yes. That is correct.

Q.165 - Okay. So if you collect that dollar from the wind generator will you pay that full dollar out to the generation provider?

MR. PORTER: Not necessarily. We will track the actual costs incurred. We have contracts in place for the procurement of regulation and load following. We anticipate that over time we will have additional contracts for procuring those services.

What we do today and what we will continue to do is we identify what our requirements are, we subtract off the level of self-supply and then procure the difference, to the extent that there is a difference, and under contract. So certainly the possibility exists that the costs are lower than the dollar per megawatt hour and --

Q.166 - I will get into that perhaps a little bit more specifically in a moment.

If the costs of the service, costs to the SO for acquiring the AGC and load following is greater than a dollar, who pays the generator the difference?

In other words, you have collected a buck from the wind generator, GENCO presumably its costs now are a buck 25. So you have got to pay $1.25 to acquire the service. You have only collected a dollar from the wind generator.

Who pays the additional 25 cents? Where does it come from?

MR. PORTER: If that happens in short term -- well, back up here. We would have separate accounts for both the revenues and expenses on this schedule 3(C). So that we will always have a record of the revenues and the corresponding expenses.

And as we have had with the CBAS services that are already in the tariff, there is notionally a potential that we would end up with a surplus or a deficit on those services.

And in the short term, certainly monthly or even within a year, I would suggest that we would retain the surplus, if it was a surplus, or try and live with the deficit, if there were a deficit, and see where we were at at the end of the year.

And it is certainly our preference and our proposal that we do not get into the situation where the procurement costs would be such that there would be a material deficit.

But nonetheless the potential exists that that would be the case. And that's I think a matter for this regulator to decide in terms of how such surpluses or deficits would be handled.

Q.167 - Okay. If I understand what you just said, Mr. Porter -- I was going to ask you about this specifically -- I understand that you are going to keep a separate Schedule 3(C) account. That will be settled monthly presumably. And deficits and surplus would be recorded there.

I guess I am concerned that if there is what I would call one Schedule 3 pot, not broken out, you would get a situation where the Schedule A and B customers, which is the load, could end up subsidizing the wind generators in Schedule C, if there are continuing deficits in the Schedule 3(C) account.

And I guess I would like to have some assurances that we are not going to get into some cross-subsidization between the load and the generators.

MR. PORTER: And I would sympathize with that concern. It is important that the expenses and the revenues associated with Schedule 3 are tracked separately from 3(A) and 3(B). And that is our proposal.

And that is -- there is a response to an Interrogatory that discusses that process, that when we dispatch the system that we look at reading energy needs and then the capacity-based ancillary services needs as are already in the tariff, and then after that the needs with respect to Schedule 3(C).

MR. MARSHALL: And just to add to that, the Settlement Agreement is pretty clear. The intent is that Schedule 3(A) would be settled in terms of the actual costs required and usage for Schedule 3(A).

Also Schedule 3(B) would be settled and done essentially on costs and revenues for 3(B). The same would be done for 3(C).

Q.168 - Well, you have certainly addressed a major concern of ours.

Mr. Porter, I think you may have started to answer this.

At page 16 of that wind study -- and you don't have to turn it up -- you basically say that the actual cost must be tracked and changes to any associated rates would be made as necessary through the appropriate approval process.

And I think you said you are going to be tracking these costs. If the costs and revenues get out of whack you are basically going to do something about it.

And when I read that it seems to me to indicate that it contemplates that you would be coming back to this Board to have those rates adjusted.

Is that correct?

MR. PORTER: Mr. Chairman, that document certainly predates by a significant number of months our proposal. And our proposal is that we would not allow the costs to exceed the dollar per megawatt hour threshold.

That being said, if we find ourselves in that situation we would have no choice but to be back before this regulator to seek a resolution of the matter.

Q.169 - But that is possible. I know that your rate is not going to increase above the dollar.

But as I talked about earlier about if your costs are greater than a dollar then you are going to have to come back before this Board to have either that rate increased or do something with that loss of revenue, because there is going to be a deficit there, correct?

MR. PORTER: Yes, that is correct.

Q.170 - And would you undertake, Mr. Porter, that as soon as the SO becomes aware of a discrepancy between its costs and the 3(C) rates that you would undertake to come back before this Board as soon as practicable in order to adjust the rate or make whatever adjustments are needed to align the costs and the expenses?

MR. PORTER: First I would say that we would be publishing the numbers. So those numbers would be available for the Board, Board Staff and market participants to track as well what the revenues and expenses are for those services.

But we would undertake, if we were in a situation where we thought -- an ongoing scenario under which there was a deficit, to bring that matter before this Board.

Q.171 - Mr. Porter, I'm going to ask you a very general question. And you answer on IR on it. No need to turn it up I believe. GENCO IR-12 we asked you whether these AGC and load following costs would be paid by the wind generator. That is the philosophy, the intent. And your answer was yes.

Now you have obviously given this matter probably a great deal more thought than I have. But is there ever -- do you ever contemplate an instance where you would have a market participant who is now associated with the purchase or production of wind energy incurring an expense associated with wind power generation?

In other words do you envisage any situation where someone else is picking up the tab for a wind generator in terms of these AGC and load following costs?

MR. PORTER: I think it was already described, the process under which the providers of the services are reimbursed. We ask for the service from the supplier. We pay for the service.

And to the extent that we capture the right costs in the dollar per megawatt hour then those costs would be paid by the wind farm market participants. And to the extent that there is an ongoing mismatch that would be addressed by the Board.

The only scenario that I can think of as to the extent that if in capturing the costs incurred specific to the -- as a consequence of the wind being added, if we miss anything in that, right, if we were off by a megawatt in terms of the amount of regulation that we think is required or something like that, and we ended up committing a unit, and that cost not being tracked as being a result of wind being added, then it may very well be picked up by the market under the residual uplift cost.

There is that possibility, but only if our process doesn't exactly capture every single dollar.

Q.172 - As it stands now though, any pluses or minuses in this Schedule 3 account, that normally wouldn't go into the RMC and be socialized out. That is not the intent, correct?

MR. PORTER: That's correct.

Q.173 - Mr. Kennedy just pointed out that maybe in some of my questions I may have left the wrong impression.

Just for clarification, Mr. Porter, where these wind generators -- you say they can self-supply AGC and load following.

Is it correct that they can self-supply 100 percent of that? There is no limitation? They are not capped in any way?

MR. PORTER: Yes. That's correct.

MR. MORRISON: Those are all my questions, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Morrison.

We will adjourn for lunch and be back at 1:30 at which time Mr. Belcher will be up.

(Recess - 12:15 p.m.- 1:30 p.m.)

CHAIRMAN: Mr. Kenny?

MR. KENNY: Mr. Chairman, we have the undertaking response that was requested by Mr. MacDougall this morning from Mr. Marshall. Offer that.

CHAIRMAN: All right. We will assign an exhibit number to that response. That will become exhibit A-18.

All right. Mr. Belcher? Okay. Proceed.

MR. BELCHER: Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. BELCHER:

Q.174 - I just have a couple of brief questions for the Panel. And they are mostly clarifications. Good afternoon.

To begin with could we go to exhibit A-5. And in A-5 I'm looking at the red line Schedule 5. And it is on the top of page 97.

My understanding is going into the year you are going to estimate your ancillary services and then divide them by 12 and apply the formula on the bottom of page 96?

MR. PORTER: The formula on page 96 would be applied monthly. And just to be absolutely clear what that formula says, we would take the monthly NBSO expenses for that service.

And then, if I could summarize it, prorate that across all of the parties that are procuring the ancillary service in that month, in accordance with the Settlement Agreement.

Q.175 - So for the month, going into the month we will have an estimate of say what the operating reserve is, based on your published rates and your obligation for the Maritimes, say it is 100 megawatts times the rates. Then after the month is over -- say that obligation for 10-minute spinning is 100 megawatts. After the month is completed, if it was 80 megawatts, then you are going to do a reconciliation back to the participants for the 20 megawatts. So each participant would be their load ratio share times the 20 megawatts. It would be a reduction in their bill. Do you see what I'm saying?

MR. PORTER: The determination of who -- of the self-supply versus the procurement on a customer to customer basis would happen at the start of the month.

And what this formula indicates is that we will take our total cost at the end of the month, actual costs incurred for that service and charge that out to those customers that are -- to the extent that they are not self-supplying.

Q.176 - So going into the month there will be an estimate though?

MR. PORTER: Yes.

Q.177 - Okay. And to go through my example again, let's assume that the 10-minute spinning for the Maritimes is 100 megawatts, and a good portion of that will be self-supply. Northern Maine does not self-supply its 10-minute spinning. And that is why I'm concentrating on 10-minute spinning.

So going into the month we will pay our share of the 100 megawatts which is approximately 5 megawatts. At the end of the month through a reserve sharing or whatever, the total obligation for the Maritimes is reduced down to 90 -- 80 megawatts.

Will there be a reconciliation for the participants that did not self-supply, recognizing the lower reduction in cost for the Maritimes for that service?

MR. PORTER: Our calculation on what the charge would be would take place at the end of the month. So there is no need for a reconciliation. We will know what the costs were in that month, the actual costs incurred.

And as discussed in this documentation we are now procuring some of these services on a monthly basis and another component hour by hour. But before we send any invoice to the customer we would know the total monthly and hourly components for that calendar month. And we would take that into account in the calculation.

So there is not really a need for -- the dollars end up being the same as what you are describing. But there is no need for a reconciliation. Because we only do the calculation once. And we do it after we know what the actual costs are.

Q.178 - So at the end of the month you are just going to send out what your actual costs were?

MR. PORTER: Yes. That is correct.

Q.179 - Okay. Unlike how it is done today?

MR. PORTER: That's correct. This is a much simpler approach. And it arises from the Settlement Agreement. And again we would -- there will be no unknowns. We will know what our costs were. We will know the total. We will know which customers were not self-supplying. And we know what their obligation was. And we will be able to calculate on one iteration what their charges will be and send that out in the invoice.

Q.180 - Thank you. Back to the rates, in northern Maine, in order to serve load, companies that are looking to come in and serve load are always calling and asking how much it is going to cost.

And I always refer -- for ancillary services I always refer them to your tariff. And these red line versions,

it appears there is not going to be any published dollars per kilowatt year, month, cost for ancillary services.
Is that information going to be available to potential participants, transparency?
MR. PORTER: The answer is yes. And I will give you a couple of examples. One is that we will show -- the historical will be published on our website.
So a party could go and see month by month what the total quantity of CBAS sales were and what the total revenues were received for those services, and thereby would have an indication as to the historical trends on a dollar per kilowatt of load.
We were also getting consideration as to how we would provide that same information on a prospective basis, and are of the opinion that to the extent that we have a forecast of expected usage that we could show for illustration purposes an example calculation of what the charges would be on a per kilowatt basis.
Q.181 - For instance --
MR. PORTER: I'm sorry. Mr. Chairman, those numbers would not show up in the tariff. It's truly a formula-based charge. And so the intent is that the tariff include the formula, not a dollar per kilowatt charge.
Q.182 - For instance if I have a potential 10 megawatt load

and I know my transmission is going to be 10 times the transmission rate, there will be a spot -- or on your website I will be able to go and say I have got 10 megawatts of load, apply it to this rate for Schedule 5 to get an approximate cost?

MR. PORTER: Yes. That is correct.

Q.183 - Thank you. My final question is tie line benefits. My understanding in the questions this morning, right now the Maritimes balancing area does not have a capacity credit for tie line benefits?

MR. MARSHALL: There is a 100 megawatt reserve sharing credit that started July 1 this year. The tie line benefits that we discussed this morning and that we have provided the response, undertaking response to, relate to the long-term adequacy -- capacity adequacy calculations in the system to meet NPCC criteria one day in 10 years. Inherent in doing that there is no specific amount of tie line benefit that we say we rely on this year over year. It's a calculation that's done. And if there is a requirement to utilize tie line benefits to demonstrate that we meet the criteria, then you back into how much tie line benefit you are utilizing in order to meet the criteria. That's the methodology that has existed. And that's the methodology that is explained in the undertaking.

But in the market rules the requirement on a capability period basis is that parties have to have capacity to fulfil their obligations. The only credit that's available under those rules will be the 100 megawatts of reserve sharing for -- shared between 10-minute spinning and non-spinning reserve.

Q.184 - So the 100 megawatts for reserve sharing, that load is your operating reserve's obligation for the region?

MR. MARSHALL: Yes.

Q.185 - And then it is passed on to the participants through their load ratio share?

MR. MARSHALL: Yes.

Q.186 - And that in effect somewhat lowers your capacity obligation based on the formula used to calculate your capacity obligation, which includes operating reserves? It is your peak load plus operating reserves --

MR. MARSHALL: Yes.

Q.187 - -- adjusted for outages?

MR. MARSHALL: Yes.

Q.188 - Yes. So I guess I don't understand -- ISO New England utilizes tie line benefits to reduce the overall region's capacity obligation?

MR. MARSHALL: In their three-year forward capacity market --

Q.189 - The reason --

MR. MARSHALL: -- which is a means of procuring capacity that they have to demonstrate to NPCC that they meet the long-term adequacy of one day in 10 years reliability.

Q.190 - Our capacity obligations. Northern Maine's is based on the same methodology that New Brunswick market rules are.

In that scenario we look I believe it is two months prior to the capability period to determine the capacity obligation?

MR. MARSHALL: Four months prior.

Q.191 - Four months prior --

MR. MARSHALL: You have to have it guaranteed two months prior.

Q.192 - Yes. Two months to have it. So there is no way to infer any type of tie line benefits in the short term. Because we essentially work it on the short term?

MR. MARSHALL: That's correct. Other than the 100 megawatts of NPCC reserve sharing there are no other tie line benefits on a capability period basis.

Q.193 - And New England does it because they are looking out three years in a forward capacity market.

MR. BELCHER: Thank you, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Belcher. Mr. Theriault? Anytime you are ready.

MR. THERIAULT: Thank you, Mr. Chairman. Before I start, Mr. Chairman, I just -- as I proceed through my cross-examination I have taken the liberty of photocopying some excerpts from the evidence so that we don't have to all pull out binders and go through it. And as I get to that point I will have them distributed.

CHAIRMAN: Thank you.

CROSS-EXAMINATION BY MR. THERIAULT:

Q.194 - Panel, good afternoon. Before I start, Mr. Marshall, I do have one question for you. Since you are no longer an employee with the System Operator, I'm assuming that your evidence here today binds the New Brunswick System Operator?

MR. MARSHALL: I'm assuming that too. But you can get Mr. Porter to swear to it.

MR. PORTER: Yes, I would agree. We certainly welcome Mr. Marshall as an integral member of the Panel. And we treat his statements as if they were ours.

MR. THERIAULT: Thank you.

Q.195 - Now Panel -- and again whoever wishes to answer -- would you agree that under the Electricity Act the NBSO is a separate legal entity?

MR. MARSHALL: Yes.

Q.196 - And that it is also a not for profit organization?

MR. MARSHALL: Yes.

Q.197 - And now is the NBSO intended to be separate from the NB Power group of companies?

MR. MARSHALL: It is separate from the NB Power group of companies.

Q.198 - And could you explain to me why it was structured this way?

MR. MARSHALL: Why it was structured in what way?

Q.199 - That it would be --

MR. MARSHALL: That it was separate from the NB Power group of companies?

Q.200 - Yes. It would be a separate company?

MR. MARSHALL: It was done so in the Electricity Act based on I think recommendations of the Market Design Committee, of the -- it was an additional finance committee of government looking at restructuring of NB Power.

So it was on the basis of advice from that and stakeholders, a long process involving the Select Committee on Energy that held hearings around the province. It was on the basis of all of that background that that decision was taken by government at that time.

Q.201 - Do you have -- could you explain as to why? I guess prior to 2004 the functions of the New Brunswick System Operator were performed under the NB Power umbrella, is that correct?

MR. MARSHALL: Yes.

Q.202 - And so why was it felt necessary to separate the N.B. System Operator?

MR. MARSHALL: I believe it was felt necessary to separate out the operator. Because the original driver, one of the original drivers behind the whole restructure in the industry was FERC Order 888 in 1996.

And by the time New Brunswick got to doing the Electricity Act in 2003 and '4, it was apparent in the United States under FERC that there were a lot of charges and concerns about the potential for nondiscriminatory behaviour between entities in the same corporation, even though there was a code of conduct and that was the minimum requirement.

But there were challenges that that was not sufficient and that there was a requirement or a need under FERC Order 2000 and others that there should be independent operation of the system from the owners.

And so on the basis of that information and the direction, I believe that's the reason why the government took the position to separate the operator.

Q.203 - Thank you. Now with respect to the objects for the New Brunswick System Operator contained in the Electricity Act, I'm going to ask you to respond. I'm going to read you one of the objects. And I'm going to ask you to respond to a series of questions.
And one object listed in the legislation is to enter agreements with transmitters giving the System Operator the authority to direct the operations of their transmission system.
So currently -- my first question would be what transmitters have signed agreements with the NBSO?
MR. MARSHALL: NB Power Transmission Corporation and WPS Canada Generation Inc.
Q.204 - And have these agreements been filed with the Energy and Utilities Board?
MR. MARSHALL: I'm not aware that they have or have not.
Q.205 - Okay. Now under one of the -- under the object I just read, I'm going to ask you what is meant by directing the operations of a transmission system?
MR. MARSHALL: It means making all of the decisions, analysis, you know, to prepare the system for operation, right down to directing exactly what operations are going to take place in order to run the system in a reliable manner.

Q.206 - Now another object under the legislation is to direct the operation and maintain the adequacy and reliability of the SO controlled grid.
And my question is what is meant by the SO controlled grid?

MR. MARSHALL: The SO controlled grid is the transmission system, 69 KV and higher, located inside New Brunswick. So it's all of the transmission at that level owned by NB Power Transmission Corporation and WPS Canada Generation Inc.

Q.207 - And what is meant by directing the operations of the NBSO grid? Specifically what activities are involved in this direction?

MR. MARSHALL: The coordinating outages, planning operation, checking voltage supplies, running contingency analysis, allowing and scheduling of outages right down to the -- up to the switching in order to operate the system.

Q.208 - Now how does the NBSO maintain the adequacy of the SO controlled grid?

MR. MARSHALL: The adequacy of a transmission system has to meet -- again similar to the undertaking that we did for Generation, adequacy of the generation system. There are similar requirements for the transmission system through NPCC and NERC that you have to meet what is called the N minus 1 criteria.

That is that the system has to be able to be sufficiently -- have a sufficient capability to be able to continuously supply load given that any one of the elements of the system are out of service, or fail instantly, you would be able to recover from that. So it's the N minus 1 criteria as to determine the adequacy of the system.

Q.209 - Does the responsibility for implementing any adequacy plans remain with the NBSO?

MR. MARSHALL: Oh, absolutely. When I talk about contingency analysis, we have a contingency analysis program that runs continuously in real time scanning through all the possible contingencies that could occur on the system.

And if it comes up that there is one that may cause an issue, an alarm will come to the operator to take action to always stay at least one contingency away. So in real operating time we, our operators, have to take actions to maintain that.

In the longer term our responsibility is to coordinate with transmission owners the plans for the development of the system that will meet that adequacy requirement in the long term.

Q.210 - Thank you. And another objective is to procure and provide ancillary services.

And my first question on this objective is who provides the Schedule 1 and 2 mandatory ancillary services that NBSO procures?

MR. MARSHALL: Well, first of all NBSO provides Schedule 1 service totally. And they don't procure it. They -- the procurement for Schedule 1 service is the operating budget and cost of running the N.B. System Operator. That's for procurement through all of its staff, people and resources.

Schedule 2 service, voltage support is procured from NB Power Generation from all of their generation resources on the system. It's procured under contract from them and then supplied by NBSO to transmission customers.

Q.211 - Now another objective is to maintain the adequacy and the reliability of the integrated electricity system.

And my first question is what is meant by the integrated electricity system?

MR. MARSHALL: I think in that sense the integrated electricity system means the total system, all of the generators, all of the -- not just the NBSO grid but all of its interconnections and the effect of its operation on external systems as well as the effect on connected load inside the system.

Q.212 - And again it may be related to the previous answer.
But what components make up this integrated electricity system?

MR. MARSHALL: I think it's everything that is synchronized and connected to the system, from the lights in this room to Point Lepreau down this road.

Q.213 - And how does the NBSO maintain the adequacy of the integrated electricity system?

MR. MARSHALL: By having all of the market participants follow the market rules.

Q.214 - And does the responsibility for implementing any adequacy plans remain with the NBSO?

MR. MARSHALL: Yes.

Q.215 - Now how does the NBSO maintain the reliability of the integrated electricity system?

MR. MARSHALL: Through the market rules there are requirements for load supplying entities that have enough resources under contract, as we just discussed with Mr. Belcher, four months prior to the capability period, and absolutely finalized two months prior to the capability period that they have enough resources in place to satisfy the market rules that are administered by New Brunswick System Operator.

And that will guarantee sufficient capacity and energy in order to provide for reliable supply to all load customers in the system through the coming winter capability period.

MR. THERIAULT: And the --

MR. MARSHALL: And I'm not quite done. And in addition to that, okay, on a longer term basis, NBSO conducts the resource adequacy studies that we submitted in evidence here that are filed with NPCC every year, as well as we coordinate with NB Power Transmission the transmission adequacy studies to demonstrate that the grid will meet the N minus 1 criteria.

So those are reports that are done and updated every year and filed with NPCC. They are reviewed through the NPCC process through its committee structure by parties of all other areas, which would be Ontario, Quebec, New York and New England, and will get all the way through and finally approved by the NPCC Reliability Coordinating Council and accepted as adequate.

Q.216 - And does the responsibility of the reliability plans remain with the NBSO?

MR. MARSHALL: Absolutely. That's what the Electricity Act says.

Q.217 - Another objective under the Act is "to undertake and

coordinate power system planning and development
responsibilities to maintain and ensure the adequacy and
reliability of the integrated electricity system."
And again my first question --

MR. MARSHALL: There is more to that one.

Q.218 - Okay. But that is the objective I'm citing.

MR. MARSHALL: If you are going to cite an objective please
give me the whole objective.

Q.219 - Okay.

MR. MARSHALL: Because the second part of that is very
important for the Board to understand.

MR. THERIAULT: Just bear with me just for a second,
Mr. Chairman.

CHAIRMAN: Certainly.

MR. ROHERTY: I think he's referring to section 42 (i), I
think.

MR. MARSHALL: I also think it's in exhibit A-6 under IES
Supplemental IR 9. And as Mr. Roherty said, it is object
-- section 42 (i) of the Electricity Act.

CHAIRMAN: Mr. Marshall, do you have a copy of that in front
of you?

MR. MARSHALL: Yes.

CHAIRMAN: Because I'm just thinking, if your problem with
the question was that he didn't cite the provision in its

entirety, perhaps you might just read out the balance of it. And it would probably help us move along.

MR. THERIAULT: I have since found it.

MR. MARSHALL: Yes. It says to undertake and coordinate power system planning and development responsibilities, to maintain and ensure the adequacy and reliability of the integrated electricity system for present and future needs and for the efficient operation of a competitive market.

Q.220 - Okay. Now my question, my first question with respect to that is what is meant by the power system?

MR. MARSHALL: It says coordinate power system planning and development. That would be a combination of generation adequacy and transmission adequacy, system in combination, to maintain and ensure adequacy and reliability of the integrated system.

Q.221 - Okay. Now does this statement mean that the NBSO only undertakes power system planning and some other entity implements the plan?

MR. MARSHALL: It doesn't -- it doesn't specifically say who would implement the plan. It says we have a responsibility to undertake and coordinate the planning and development to meet the reliability and adequacy requirements.

Q.222 - And who would implement the plan then? Is that part of the responsibility of NBSO?

MR. MARSHALL: Market participants would implement the plan to construct new generation facilities or contract for new resources. Transmitters would build the transmission.

But our understanding all along was that if in coordinating those plans and going forward, existing transmitters were not prepared to build transmission that was deemed to be necessary in order to maintain reliability of the system then NBSO could undertake to have that transmission built by a third party and put into the tariff, subject to Bard approval on the tariff.

Q.223 - And I guess that might lead into my next question.

Let's suppose that GENCO comes with a proposal to invest in a new generation facility and this proposal does not meet with the current NBSO planning requirements.

How would you deal with this matter?

MR. MARSHALL: It implies that somebody building new generation would be outside our planning requirements. I don't think that's possible.

If somebody is going to build new generation it's going to improve the adequacy of the system and make the system more reliable.

So it will not fail to meet our requirements. It may exceed them. But that's a market choice that the market participant would make.

Q.224 - So you are saying that situation can't happen?

MR. MARSHALL: I don't think it can happen. Now I'm not all-knowing. But I don't think it can happen.

Q.225 - Now I think it would be helpful if we started with a better understanding of the differences in the various services offered by NBSO and the attendant schedules that go with them.

And I'm going to ask some questions that are probably pretty basic to you. But I would ask you to bear with me. The service associated with Schedule 1 is referred to "scheduling system control and dispatch service", is that correct?

MR. MARSHALL: Yes.

Q.226 - Okay. And this is a mandatory service?

MR. MARSHALL: Yes.

Q.227 - And does this -- by "mandatory" does this mean that market participants must purchase this service and they must purchase it from the NBSO?

MR. MARSHALL: We could have market participants that don't buy that service. It's important that you understand it's -- you can have a market participant that's a generating market participant and not take transmission service. What that means is it's mandatory service to go with transmission. So any transmission customer taking network service or any transmission customer taking point-to-point service, it's mandatory that they buy Schedule 1 service along with that transmission service.

And that's not necessarily that all market participants have to do that. There are other ways to participate in the market.

Q.228 - Okay. And is Schedule 2 -- Schedule 2 is a mandatory service as well?

MR. MARSHALL: Yes.

Q.229 - And does this mean that market participants must purchase this service and they must purchase it from NBSO?

MR. MARSHALL: Yes. Similarly to what I just said for Schedule 1. Any transmission customer taking transmission service must purchase Schedule 2 service along with it. And they must purchase it from NBSO.

Q.230 - And do Schedules 3, 5 and 6 refer to capacity based ancillary services?

MR. MARSHALL: Yes.

Q.231 - And with respect to these CBAS services, are they mandatory, like Schedule 1 and 2? Or can market participants self-supply a portion of these services?

MR. MARSHALL: They can self-supply a portion of the services. But the services are mandatory if you are supplying load. The issue is how you procure them. There is flexibility in how they can be provided.

It's not mandatory that they purchase them from NBSO.

Although at the current point in time, under the current Board policy, 10 percent of those services must be purchased for NBSO. 90 percent can be self-supplied.

Q.232 - So it is fair to say then that the application by -- this application by the NBSO affects two types of services, those that must be purchased from the NBSO and those that could be self-supplied by market participants --

MR. MARSHALL: Yes.

Q.233 - -- in general terms?

Now I would like to move on and get some understanding of the nature of this application and to get a clear picture of the intent of the NBSO moving forward.

Now this application, is it made under Section 111 of the Electricity Act?

MR. MARSHALL: I believe it is, but subject to check here, yes. And we can find that in A-1, page 1, under tab 1.

Q.234 - Okay. And would you agree Panel that the Section 111 reads as follows, the SO may make an application to the

Board for approval of a tariff pertaining to transmission services or ancillary services or both?

MR. MARSHALL: Yes, that is correct.

Q.235 - And do you agree that under the legislation your application to the Board must be for approval of a tariff?

MR. MARSHALL: Yes.

Q.236 - And do you agree that tariff is defined in the Electricity Act as a schedule of all charges, rates and tolls, terms and conditions and classifications, including rules for calculation of tolls established for the provision of either and both of the following, (a) a transmission service, (b) an ancillary service?

MR. KENNY: Mr. Chairman, these particular questions are interpretations of a statute. Witnesses aren't qualified to give interpretations, what they mean et cetera. They can give perhaps their opinion what it is. It is not binding. But these are questions of law that perhaps they have to be established. And they may be covered in argument, but these are actually questions of law put to these witnesses.

CHAIRMAN: Well it may be close to that line, but are you looking for his view of a legal interpretation or simply --

MR. THERIAULT: No, I just --

CHAIRMAN: -- cover what kind of practical application they have in terms of bringing an application such as this before the Board?

MR. THERIAULT: Exactly, that's the issue. And I think my last question was simply I read the definition of tariff and asked him if he agrees that that's the definition of tariff as contained in the Electricity Act. I am not asking for an interpretation.

CHAIRMAN: I think that would simply be the question of whether or not he could read the application, if that's what you are asking. Just essentially putting that on the record and proceed.

MR. THERIAULT: That's correct. Thank you.

Q.237 - So would you agree that --

MR. MARSHALL: Yes.

Q.238 - So you would agree then that a tariff is among other things a toll, rate or charge?

MR. MARSHALL: Yes. And a methodology to calculate it.

Q.239 - Yes. And I say among other things. So would you agree that the NBSO is required under the legislation to file for changes to a tariff and that the Board can only approve a tariff or changes to a tariff?

MR. MARSHALL: That's my understanding, but I think it is a legal issue.

MR. KENNY: That's the point that I am making, Mr. Chair, is that particular question is clearly asking this witness to interpret the statute. That's the point that I am making.

CHAIRMAN: Can you rephrase that?

MR. THERIAULT: Sure.

Q.240 - When you want to -- what's the purpose of applying to the Board? Why are we here today?

MR. MARSHALL: We are here to make changes to the tariff.

Q.241 - Thank you. And that's the purpose of this current application?

MR. MARSHALL: Yes.

Q.242 - Now is it not true that in exhibit A-5, clarification of tariff changes at tab 1, page 2 --

MR. MARSHALL: A-5. There is no tab 1.

CHAIRMAN: I don't see a tab 1 in A-5.

MR. THERIAULT: It's the first tab in the clarification of tariff changes, entitled "Introduction and Summary".

CHAIRMAN: Thank you.

Q.243 - And is it true that at page 2 of the NBSO refers to moving away from fixed rates to an annual approval of a Schedule 1 and Schedule 2 revenue requirement?

MR. MARSHALL: Yes.

Q.244 - And now as president and CEO of NBSO since 2004 and our involvement in the electricity industry, have you had the opportunity to become familiar with the Electricity Act?

MR. MARSHALL: Yes.

Q.245 - And are you aware of any place in the Electricity Act where there is a reference to an annual revenue requirement, for applying to the Board for approval of an annual revenue requirement?

MR. MARSHALL: There is reference to revenue requirements in the Electricity Act. Not necessarily to an annual approval of it.

Q.246 - Thank you. So would you agree that in order to proceed with this or any future applications, the NBSO must file with the Board for approval of any changes to an tariff that it administers?

MR. MARSHALL: I guess that a question of interpretation again. What we are applying for is a methodology for schedules for the ancillary services and a methodology for Schedules 1 and 2 based on an annual revenue requirement, approval of the revenue requirement.

So as regards to that annual revenue requirement, yes, it would be a requirement of the Board to approve that. And at this point in time we are asking for a formula basis so that the formula would be approved at this point in time. The number that goes into the formula would be approved on a year over year basis.

Q.247 - And we will get into that, but I guess my question is more basic than that. And it was do you agree that in order to proceed with this or any future applications, the NBSO must file with the Board for approval of any changes to any tariff it administers, regardless of what the definition of tariff is?

MR. MARSHALL: Yes.

Q.248 - And obviously as we see here, would be to file evidence to support any change to the tariff?

MR. MARSHALL: We are talking about the Open Access Transmission Tariff.

Q.249 - That's correct. Now in your clarification document is the NBSO proposing to make an annual application for approval to change a tariff or tariffs?

MR. MARSHALL: Yes, we are proposing that we make an annual filing of the Schedule 1 revenue requirement for approval by the Board so that the charges calculated under the formula proposed would be approved on a prospective basis year over year.

Q.250 - But I think my question was is NBSO under the clarification document proposing to make an annual application for approval to change a tariff or tariffs?

MR. MARSHALL: No, we -- yes, we are not going to be approving, if you take a tariff document as being -- well there is copies in Schedule -- in Appendix A-1. The actual tariff document, there would be no changes to the actual document. So there would not be an application to change the tariff. The methodology would be approved in this hearing and written into the tariff. What would be changed and approved is the budget and the revenue requirement that goes into that formula which would alter possibly the charges going out to customers, but the tariff would not be changed.

Q.251 - But it would alter the charges?

MR. MARSHALL: It could alter the charges, yes.

Q.252 - Thank you. Now I would just like to go through background here to this present application. How many -- first of all, how many rate applications has the NBSO made before this or the predecessor Board, the Public Utilities Board?

MR. MARSHALL: NBSO has had two hearings related the transmission tariff. And NB Power Transmission Corporation had one hearing, you know, prior to that and there was some follow-up on other things out of that hearing. So it --

Q.253 - So are they where the decision was of the Board was May 1st 2005 and another one March 1st 2006? I guess just so I can clarify it, Panel. I'm looking for specifically the NBSO applications. I'm not concerned about prior to 2004 with the NB --

MR. MARSHALL: Okay. The only NBSO application I'm aware of is the one we filed in January 2005 that went into effect May 1st, 2005.

Q.254 - There was not another one in 2006?

MR. MARSHALL: Okay. Mr. Porter reminds me, in terms of actual charges that was the one, but then there was an adjustment to energy and balance treatment schedule 4 that went into effect in the next year.

Q.255 - Which would be 2006?

MR. MARSHALL: If you considered it a separate application, then there were two.

Q.256 - And were these applications, whether you consider it one or two, were they made for a fixed tariff for schedules 1 and 2?

MR. MARSHALL: The schedule 1 and 2 charges were done in the 2005 application.

Q.257 - So it was an application for a fixed tariff for schedule 1 and 2?

MR. MARSHALL: Yes, it was. Yes.

Q.258 - Now on May 1st of this year did the NBSO submit an application -- they submitted an application for changes in its tariffs on May 1st of this year, the original application?

MR. MARSHALL: Yes, that's correct.

Q.259 - Okay. And this application was for an approval of changes to the open access transmission tariff?

MR. MARSHALL: Yes.

Q.260 - And did this application amongst other items propose fixed tariffs for schedule 1 and 2?

MR. MARSHALL: At that point in time, yes.

Q.261 - And were the proposed changes described as changes to schedule 1 and 2 rates?

MR. MARSHALL: Yes.

Q.262 - So would it be fair to say that the application dated May 1st was an application to have fixed tariffs for schedules 1 and 2. and that this application was similar in intent to the previous application made by the NBSO?

MR. MARSHALL: Yes. It was more encompassing because it dealt with schedules 3, 5 and 6 as well.

Q.263 - But as it relates to 1 and 2 it was similar in intent to the 2005 I believe application?

MR. MARSHALL: Yes. Actually the 2005 application only dealt with schedule 1 and schedule 7 and 8, not schedule 2.

Q.264 - Now when did the NBSO start working on the May 1st application, roughly?

MR. MARSHALL: I believe last year about this time.

Q.265 - Now was the market advisory committee and the NBSO board advised and involved in the preparation of the May 1st application?

MR. PORTER: They were kept up to date in terms of the process and certainly the market advisory committee was consulted on more than one occasion.

Q.266 - Now earlier we went through the objectives of the NBSO, and would you agree that the May 1st application was intended to help the NBSO fulfil those objectives?

MR. PORTER: Yes, that is correct.

Q.267 - And would it be fair to state that since the application was filed with this Board that the NBSO staff, its board and the MAC were satisfied that the initial May 1st application was sufficient to meet its objectives under the Act?

MR. PORTER: I can't answer on behalf of all the market participants -- all the members of the market advisory committee, but at that time certainly the NBSO staff was comfortable with that application.

Q.268 - And your board of directors.

MR. MARSHALL: But I might add that as far as the MAC goes, there was parallel work going on in consultation with the MAC related to the strawman as to how ancillary services should be handled and are there possible changes with the dealing ancillary services that would better allow us to carry out our functions and meet our requirements. And that was going on, okay, while we were preparing the application to go forward, and those discussions carried beyond that.

Q.269 - And I think we will get into the strawman here in a little bit. Now I would like to look at some events before the May 1st filing, and more importantly events that -- the filing and before the clarification changes filing -- which has a July 29th date. I want to look at the CBAS surpluses and I'm going to ask you in what fiscal year did the CBAS surplus first become an issue?

MR. MARSHALL: I was just trying to retrieve the same table that -- here. We were -- yes. It's A-4, cross-examination -- or interrogatory responses from the EUB. So it's IR-10 from the EUB, page 63, and document A-4. And it outlines the surplus deficit from all of the sources, whether it was schedule 1, schedule 2 or CBAS running across that the surplus -- that there was a surplus that started in 5, 6, and that it grew significantly in 6, 7 and 7(A).

Q.270 - So the answer to my question, it first became an issue in '05, '06.

MR. MARSHALL: It was a surplus, it wasn't an issue.

Q.271 - And in '05, '06 what was the method used to distribute the surplus, or afterwards how did you deal with -- what method did you use to deal with that surplus?

MR. MARSHALL: The surplus made up for a deficit from '04, '05, 114,000. 300,000 was retained to go into the retained surplus account. And 310,000 was rebated and I believe it was rebated proportional to transmission and CBAS customers proportional to their usage.

Q.272 - Now that proportional usage method, was that negotiated between the NBSO and the market participants?

MR. MARSHALL: At that time I believe we came up with that method and filed a letter with the Board to say here is how we think it should be done, and the previous Board accepted that.

Q.273 - So it was presented to the previous Board?

MR. MARSHALL: It was presented to the PUB.

Q.274 - But I guess the actual surplus settlement itself, was there negotiation between the NBSO and the market participants to come up with a rebate formula?

MR. MARSHALL: No, not at that time.

Q.275 - And I think you said the next surplus was in -- CBAS surplus occurred in '06, '07?

MR. MARSHALL: Yes.

Q.276 - And what was the method used to distribute that surplus?

MR. MARSHALL: Well in that particular year the schedule 1 and 2 surplus -- well there was no surplus, there was a small deficit. So for '06, '07 the -- all of the CBAS was distributed back to network load type customers, okay. It was the net amount which essentially was almost the total of the CBAS surplus. There was a small -- a small deficit that covered off schedule 1 and 2, and the CBAS was supplied back to CBAS customers and parties that had to provide the CBAS server.

Q.277 - And how was this method arrived at?

MR. MARSHALL: It was arrived at in negotiation with all of those parties.

Q.278 - Okay. And I guess -- and I know there was a surplus for '07, '08, but at some point in time prior to this application and as part of the negotiation process was the strawman model developed and presented as a method to eliminate most of any future CBAS surpluses?

MR. MARSHALL: Prior to when?

Q.279 - Prior to -- let's say prior to the '07, '08 surplus. Or as part of -- I guess what I am trying to figure out is when was that strawman model developed?

MR. PORTER: I think as Mr. Marshall indicated earlier, this application -- we were working on this application about a year ago. The notion of the strawman model, I don't have the exact date, but I think it would have been early in the new year we were started to work on that, and certainly -- and it was distributed to market advisory committee members at a couple of different points in time.

Q.280 - Okay. And the strawman model was presented as a method to eliminate most of any future CBAS surpluses?

MR. PORTER: Yes, that's correct. It was introduced to identify all the issues that were contributing to the surplus and to seek ways to mitigate those surpluses.

Q.281 - And was this strawman model submitted as part of the May 1st application?

MR. PORTER: Yes, it was.

Q.282 - And since it was part of the May 1st application the NBSO staff, the NBSO Board and the market advisory committee must have been satisfied that it dealt with the issue of future CBAS surpluses.

MR. PORTER: Just back on that, I want to verify. In my understanding I don't think the strawman was submitted.

Q.283 - I believe it was.

MR. PORTER: Okay. May 1st. Yes. Okay. So it was submitted May 1st, A-1.

Q.284 - Okay. And so I guess I will repeat my question. Since it was part of the May 1st application I would assume the NBSO staff, the NBSO board and the market advisory committee were satisfied that it dealt with the issue of future CBAS surpluses?

MR. PORTER: That document addressed the major issues that were identified at that time and market participants were generally comfortable with that approach, yes.

Q.285 - Would it be fair to say that the strawman model was integral to your May 1st OATT application?

MR. PORTER: The strawman model as submitted on May 1st -- aspects of that were used in the design of the proposed new rates for the capacity based ancillary services.

Q.286 - So it was integral to your May 1st application?

MR. PORTER: Part of it was an important contribution to the calculation of the rates. At which point are you asking about dates? The date on that document is March 31st, 2008. And that would have been at least the second iteration. There was a version before that that was distributed to the market advisory committee for its review.

Q.287 - Now in order to secure market participant support for the strawman model, was there a proposal to take $100,000 from retained surplus in order to increase the size of the CBAS surplus for distribution to those same market participants?

MR. PORTER: No.
Q.288 - Did any of the market participants indicate that they would not accept the strawman model without this $100,000?
MR. PORTER: The $100,000 was not discussed by the market advisory committee.
Q.289 - That's not what I was asking. I will repeat the question. I will start back at -- in order to secure the market participant support for the strawman model, was there a proposal to take $100,000 from retained surplus in order to increase the size of the CBAS surplus for distribution to these same market participants?
MR. PORTER: No.
Q.290 - And did any of the market participants indicate that they would not accept the strawman model without this $100,000?
MR. PORTER: No.
Q.291 - Did the NBSO receive any benefit for offering $100,000 of its retained surplus to the market participants?
MR. PORTER: The Settlement Agreement which included the $100,000 contribution led to firm commitment on paper from those market participants involved that they would support the strawman proposal. To that point in time we had not had that. We had a -- from the market advisory committee had a consensus. But we did not have anything -- and

those market advisory committee members are acting on behalf of their sectors in many cases, not the companies. So we -- what we received as a consequence of the $100,000 contribution was a firm commitment on paper to support the strawman proposal.

Q.292 - So then to go back and ask you the questions again, in order to secure the market participants support for the strawman model was there a proposal to take a hundred thousand dollars from retained surplus in order to increase the size of the CBAS surplus for distribution to the same market participants? And if I understood what you just said I guess the answer would be yes?

MR. PORTER: I mean the question as asked earlier about at the time that the strawman model was first put out there and they said that the hundred thousand dollars was not discussed at all. But the hundred thousand dollars was discussed in the context of the negotiation of the Settlement Agreement which involves a long list of items that lead to a much better arrangement with respect to both CBAS surplus, but also Schedule 1 and 2 of revenue and expense mismatches. And also the issue of NBSO risk mitigation on revenue usage volumes. And also the treatment of the retained surplus.

Q.293 - But those same issues could have been brought forward without offering the -- without the additional hundred thousand dollars?

MR. PORTER: They could have been brought forward in an application, but by the negotiations that took place and the execution of the Settlement Agreement we are able to come there today with it on paper that the affected parties have agreed to these various components and we believe that that would a significant amount of regulatory efficiency to the process.

MR. MARSHALL: And the other part -- I might add to that that the hundred thousand dollars, we had $300,000 of retained surplus. The issue was we were going to get solid support from the market participants to the methodology that is proposed here that effectively eliminate the total surplus. So the issue is we are going to give the $300,000 back at the end of this year if this was all accepted. This was simply a matter of well we will give a hundred thousand back in 2007, '08, as opposed to waiting till the end of '08, '09. To us it didn't make a whole lot of difference. But if that what was going to guarantee we are going to get support to get to what we think is a better process to deal with ancillary services, it was an easy deal to do.

Q.294 - Thank you. Now, I would like to examine the differences between the previous applications, the May 1st rate application and the revisions to the rate application contained in the clarification of tariff changes filed on July 29th. Now at this point in order to gain a better understanding of what the NBSO is now proposing in its implications, I have made a copy of PI IR-1, which I will ask Ms. Hennick at this point to give to distribute to the Board and to the parties.

CHAIRMAN: The documentation that you are handing out is simply a duplication of documents already in evidence I take it?

MR. THERIAULT: That's correct. It's just responses to PI IR-1.

CHAIRMAN: Thank you.

MR. THERIAULT: Obviously I have done it to make things streamlined, but obviously it doesn't seem to work.

Q.295 - Now before I get to that document, Panel, I just want -- in the previous rate applications the NBSO filed for changes to a fixed tariff. So previous to the May 1st application.

MR. PORTER: Sorry. Could you repeat that?

Q.296 - Sure. Previous to the May 1st application the NBSO in its previous application filed for changes to a fixed tariff?

MR. PORTER: You are referring to 2005?
Q.297 - Yes.
MR. PORTER: Yes, that's correct.
Q.298 - And those changes would have constituted a new fixed tariff at that time?
MR. PORTER: The 2005 application was for a change to the rates, the fixed rates.
Q.299 - And that would have constituted a new fixed tariff?
MR. PORTER: Yes.
Q.300 - Okay. And did the NBSO at that time understand that this tariff was fixed and that it represented the rate or charge that applied to all of the services provided by the NBSO, most particularly those in schedule 1?
MR. PORTER: Yes.
Q.301 - And on May 1st, 2008, did NBSO make an application for a change to its fixed tariff?
MR. PORTER: I think I already answered that. Yes.
Q.302 - Thank you. And again these changes would have constituted a new fixed tariff had they gone as set out in the May 1st application?
MR. MARSHALL: Yes. I -- you know -- the tariff is the tariff. It's a document this thick. It amounted to changes -- some wording through the tariff and some changes to rates. Given that that would replace the old

tariff, it would become in its entirety a new tariff document.

Q.303 - Now as part of this process on July 29th the NBSO filed the clarification of tariff document pursuant to the Board order of July 18th, 2008?

MR. MARSHALL: Yes.

Q.304 - And now I would like to refer you to the document that was just circulated which is a copy of PI IR-1 I believe. And I would like to summarize and clarify the response in that interrogatory. So will fixed rates be removed from the tariff pursuant to this application?

MR. PORTER: Yes.

Q.305 - And rates will now be variable if it is accepted?

MR. PORTER: Yes.

Q.306 - And if rates are variable does that mean that no one, including market participants and the Board, will actually know what the rates are until they are actually charged?

MR. PORTER: Yes, that is correct. Similar to the schedule 9 which is already in the tariff whereby one can only look at history to get an indication as to what the actual rates will be. And in fact with respect to this schedule 1 and 2 under this new proposal is that the revenue requirement would be known. The only unknown would be the usage. Whereas schedule 9 under the tariff today neither the -- what I would call the revenue requirement or the usage is known.

Q.307 - And is the intent of this proposal to substitute an improved revenue requirement for a fixed tariff?

MR. PORTER: Yes, in conjunction with the methodology of which we have already spoken.

Q.308 - And is this revenue requirement a forecast revenue requirement or historical revenue requirement?

MR. PORTER: It's a forecast revenue requirement to be approved by this Board.

Q.309 - Now I ask you what is the relevance of an approval of a forecast revenue requirement if any changes in forecast cost are automatically passed through to the market participants in the form of variable rates?

MR. MARSHALL: The methodology is that that's not the case. It would be an approved revenue requirement that would then be divided by 12 and that monthly charge would go out each month, be divided by the usage in the month allocated among the customers. So there is no variation in the amount of money collected.

MR. PORTER: Just to add to Mr. Marshall's comment, I believe we are talking about this IR-1 and the clarification of tariff changes --

Q.310 - Yes.

MR. PORTER: -- which is in reference to schedule 1. So I would have to agree 100 percent with Mr. Marshall that the revenue requirement is approved by the Board ideally before the start of the fiscal year and one/twelfth of that approved revenue requirement would be allocated to the transmission customers in each month.

Q.311 - So there would never be any changes to the revenue requirement?

MR. PORTER: Only on the annual basis subject to the approval of this Board.

MR. MARSHALL: And just to add to that, the -- if that one/twelfth of the revenue requirement for 12 months is collected, if that is more than what is required to cover the costs, the surplus would be rebated at the end of the year. And if it's insufficient then a shortfall would go into the application for the following year, go into the revenue requirement for the following year, and be subject to approval of this Board before it would be able to be collected on a go forward basis.

Q.312 - What I'm gathering from what I am hearing, you cannot exceed your revenue requirement?

MR. MARSHALL: Not in the year of the -- we would have an approved revenue requirement for that year. We would not exceed collecting any money more than that revenue requirement in that year.

Q.313 - So just to summarize what NBSO is proposing to do with the clarification of tariff changes. The NBSO does not want a fixed tariff.

MR. MARSHALL: That's correct. Not just the NBSO. All of the market advisory committee and the market participants don't want a fixed tariff.

Q.314 - Okay. But this is your application.

MR. MARSHALL: Yes.

Q.315 - So -- and they are not here to be questioned, so the questions are to you.

MR. MARSHALL: Three of them are.

Q.316 - The NBSO does not want a fixed tariff.

MR. MARSHALL: No.

Q.317 - And it wants a review of its prospective revenue requirement?

MR. MARSHALL: Yes.

Q.318 - And it wants to be able to vary rates as its usage varies?

MR. MARSHALL: Effectively that's what happens. With schedule 1, because the amount of revenue to be collected would be an equal amount each month, from our viewpoint that lines up with our costs much more clearly because our costs are basically flat month over month. So it mitigates the risk issue to the system operator and because that fixed amount is then going to be allocated out to customers. Because their usage varies month by month the effective rate that is being paid each month would be different. From our discussion through the Settlement Agreement customers are prepared to do that.

Q.319 - Okay. And the NBSO does not want any Board oversight on the variability of its usage?

MR. MARSHALL: We don't see any need for it.

Q.320 - And it does not want any Board oversight on the variability of its rates?

MR. MARSHALL: We don't see any need for the rates issue. It's a revenue requirement issue that the Board has oversight over.

Q.321 - I would just like to look at what other system operators are doing with respect to tariffs. Would you agree that the system operator in Alberta has fixed tariffs?

MR. MARSHALL: It is our understanding that the System Operator in Alberta has some fixed tariffs, but it also has some variable tariffs that is adjusts after the fact back to what the actual costs are to true it up.

Q.322 - And does the System Operator charge the fixed tariffs in Alberta?

MR. MARSHALL: I think for any fixed tariffs, they would charge them as they go, but they do a true-up after the fact.

Q.323 - And would you agree that the System Operator in Ontario has fixed tariffs?

MR. MARSHALL: Yes, but they also true-up after the fact.

MR. THERIAULT: Mr. Chairman, I am going into a separate set of examinations. I wonder if this might be the appropriate time to take a break?

CHAIRMAN: I think it would. We will take a 15-minute break.

(Recess - 3:00 p.m. to 3:15 p.m.)

CHAIRMAN: Anytime you are ready.

MR. THERIAULT: Thank you.

Q.324 - Just before I leave the area we were discussing just before the break, are you prepared to state unequivocally that in a given year the NBSO revenue requirement for Schedule 1 will never be exceeded?

MR. PORTER: Could you just clarify that question, exceeded in what way? Exceeded with respect to what?

Q.325 - With respect to the dollars?

MR. PORTER: The dollars collected or dollars spent?

Q.326 - The dollars with respect to the revenue requirement?

MR. MARSHALL: Spent or collected?

MR. PORTER: I repeat my question, the dollars spent or those that are collected? The revenue requirement is a term -- sorry, maybe it is the difference of terminology, but we use the term revenue requirement to be that dollar amount for which we get approval from this Board to collect from the transmission customers. And my question is are you talking about exceeding that -- collecting more than that or

spending more than
that?
Q.327 - Spending more than that?
MR. PORTER: Cannot make that commitment.
Q.328 - And what happens if it does exceed?
MR. MARSHALL: If -- as we said before, the Board would approve a revenue requirement, that would be divided by 12 and that would be the amount of money collected month or month. So for that year there would be a guarantee it wouldn't collect any more money than the revenue requirement. Mr. Porter said it is impossible to give a guarantee that you wouldn't spend more, because there can be extreme extenuating circumstances, there are issues that come arise that could be an expense that has to be dealt with that is more.
The proposal in the Settlement Agreement is if there is a deficit in Schedule 1 for a year, you wouldn't collect any more money, but if there is a deficit, NBSO

would run that deficit. And in coming back to the Board the following year would ask to have the revenue requirement adjusted. Now if the Board didn't approve all of that, some of that would have to be covered off with cutting the budget expenses. We would operate year to year only based on the approved revenue requirement.

Q.329 - Thank you. Now I would like now to focus on the tariff for Schedule, the market participants and the services offered under Schedule 1. And according to your May 1st application in Schedules 1 to 10, tab 1, page 1, the current tariff for Schedule 1 reads in part, the service can be provided only by the operator of the controlled area in which the transmission facilities used for transmission services are located. Scheduling, system control and dispatch service is to provided directly by the transmission provider (if the transmission provider is the controlled area operator) or indirectly by the transmission provider making arrangements with the control area operator that performs this service for the transmission provider's transmission system. The transmission customer must purchase this service from the transmission provider or the control area operator. And my first question is what is the control area?

MR. PORTER: The control area is a terminology that was used within the reliability circles years ago, but correspondence to the balancing area, which is the combination of Prince Edward Island, New Brunswick and Northern Maine.

Q.330 - So is it one and the same? There is a balancing area?

MR. PORTER: Yes.

Q.331 - And who is the control area operator?

MR. PORTER: NBSO.

Q.332 - And who is the transmission provider?

MR. PORTER: NBSO.

Q.333 - Now as part of your application did you provide a list of market participants? I am just wondering if I looked -- I as looking through it and in attachment E to your May 1st application, I think it is exhibit A-1, is that a list of market participants?

MR. PORTER: As indicated on that table it is a list of point-to-point transmission service customers that would not necessarily be all of the market participants. And it is most likely a subset.

Q.334 - De we have --

MR. PORTER: But the length of that list it is probably the majority of the market participants.

Q.335 - Is there anywhere in the evidence -- I didn't see it in any there that would have a complete list of market participants?

MR. PORTER: I don't believe that that was ever asked for or provided.

Q.336 - Would it be possible to get your undertaking to provide me with a complete list of market participants?

MR. PORTER: That information is available right on the public area of our website.

Q.337 - But I am asking you if you can provide it?

MR. PORTER: If the Chairman would like us to provide that we could certainly do so.

CHAIRMAN: If it is that easily available, I am sure you could provide it for first thing tomorrow. That wouldn't be a problem, I would take it?

MR. PORTER: Yes.

Q.338 - Thank you. Now insofar as Schedule 1 services are concerned, what role does each of the market participants play? Are they a supplier of capacity or purchaser of capacity? or both?

MR. PORTER: Mr. Marshall indicated earlier that the Schedule 1 service is mandatory. It is added on to any transmission usage charges. And if they wind back, there are two types of basic services available under the tariff and those are point-to-point and network. And so any customers that uses either of those two services is a user of the Schedule 1 service.

Q.339 - And I think you may have just answered it, but I am going to ask you to please describe exactly what services are provided by the NBSO under Schedule 1? And I would like you to be specific as to the activities undertaken by Staff at the NBSO to provide this service?

MR. PORTER: As we have indicated earlier, there is a one service which is -- the name is Scheduling System Control and Dispatch. But it encompasses all of the services that we provide, other than where we have explicitly identified some miscellaneous services that we -- for which we charge and receive miscellaneous revenues. So the whole spectrum of functions performed by the System Operator. And I am not aware that we have ever listed out every activity that we perform and would have no need to do so.

MR. MARSHALL: But I just comment, because I know you had an interrogatory on that before. Scheduling, control and dispatch, well under scheduling, you would have all of the work related to planning. What are the schedules for the long term adequacy? What are the schedules for coming capability periods? What are the schedules monthly? What are the schedules daily? So you are into the overall -- all of the planning activities would fall under scheduling. And then control is what goes on inside the daytime hour by hour in order to control and operate the system. A lot of those would go under control. And dispatch is right into real time. What goes on inside the actual hour, hour at a time, to operate and balance the system. I think that's how they would be broken out.

Q.340 - That's good. Thank you. Now does NBSO provide all of the services itself or does it subcontract for the provision of some of these services to another organization?

MR. PORTER: NBSO provides all of those services itself.

Q.341 - Now I would like to look at the scheduling component of Schedule 1 services and could you tell me what exactly is scheduled. Is it generation capacity, transmission capacity, both, or something else or --

MR. MARSHALL: As I just said all of the planning activities related to long-term planning coordination whether it is generation adequacy, transmission adequacy, right down to the capability period obligations which were mainly generation and load supply into the weekly and daily generation schedules to meet load for the next day, the load forecasting function, the actual scheduling of transmission, running the OASIS system that allows parties to purchase that transmission and they provide schedules of what they want to do with it, but their schedules have to be approved by us so that the overall system has a clearer

plan that is known to the
operator. All of that would
go into scheduling.

Q.342 - Now I would like to look at the dispatch component of Schedule 1 services. And again I would like to know what exactly is dispatched? Is it capacity or energy? Is it generation capacity or energy? Both or something else?

MR. MARSHALL: Dispatch is both. And just -- the energy coordinator inside the control room, we do an updated load forecast every hour on a four hour rolling average going forward. So every hour you do a new look ahead four hours and a new dispatch of all the generation of the system and an adjustment of load against that forecast, hour by hour going forward on a four hour rolling window. That's what I would -- puts into the dispatch function. So there is that short term forecast. The short term schedule of what has to be done. And then hour by hour there would be 10 minutes before the hour an actual dispatch instruction out to every generator in the system for the next hour you do this.

Q.343 - As it relates to generation capacity, who defines the order in which the units are dispatched? Is it NBSO or the supplier of the capacity?

MR. MARSHALL: NBSO determines the order based on pricing information that the owners of the generators provide. So the generation owner or the market participant for the generator provides a schedule against their obligations and they provide pricing on all of those. We will then re-dispatch based on the pricing information.

Q.344 - So is the dispatch done according to true economic dispatch?

MR. MARSHALL: Absolutely.

Q.345 - And how do market participants purchase these services? Do they nominate the quantity of each service they want?

MR. MARSHALL: What service?

Q.346 - The Schedule 1 services?

MR. MARSHALL: No. Schedule 1 service -- a customer will buy transmission through the OASIS. So if there is a point-to-point customer putting in just a request for one hour of transmission to ship a hundred megawatts to Quebec, okay, and that's approved by the operator, then along with that there is an automatic mandatory Schedule 1 charge and a Schedule 2 charge attached with it.

Q.347 - Now how does the NBSO calculate the forecast of revenue requirement for each of the Schedule 1 services -- sorry revenue? I am still stuck on revenue requirement.

MR. MARSHALL: We do a total budget of what all of the operating costs are and then you subtract out all of the forecast miscellaneous revenues from different -- sales of different types of services to get to a net revenue requirement for Schedule 1. That would be approved by the Board. And then on a month-by-month basis that number is divided by 12, which gives a fixed amount of dollars to be collected each month.

Q.348 - I guess what I am wondering though is how you forecast revenue for each service?

MR. PORTER: With respect to Schedule 1 forecast of the revenue would be based on our forecast of usage. You know, how much network service usage do we forecast and multiply that -- in the past would multiply that by the fixed rate. And with respect to point-to-point, we forecast the long-term firm reservations. And they are quite predictable, because there is a long-term commitment there for those customers to take that service, multiply the usage and the reservation quantities that is by the rates. And then with respect to short term firm and non-firm, we have looked at historical revenues received and used those to project forward to do forecast on the short-term firm and non-firm point-to-point services.

Q.349 - What is your forecast of usage for each of the Schedule 1 services for each of the Schedule 1 services for the test year?

MR. MARSHALL: Is this under -- I guess if you are asking again -- come back -- would the -- we are applying for an approval of a revenue requirement for Schedule 1. A methodology based on a revenue requirement. Not a methodology based on a projection of the services. So I don't know what your question -- is our question do we have a forecast of actual usage on the system?

Q.350 - Yes. For the test year, yes.

MR. MARSHALL: Yes, we do. And it should be in this document.

MR. PORTER: Go to exhibit A-1. It is in the -- it would be in the coloured tab 4. And then there is a white tab labelled A.

Q.351 - Under 4

MR. PORTER: I am sorry. It is under 5. There is a coloured tab -- okay, it is exhibit A-1, coloured tab number 5, and then within that section it is a white tab with the letter A. And if you flip to the third page within that section, the bottom left it says, 1.0 -- I guess the top and the bottom -- it is 1.0 cost allocation and rate design for Schedules 1 and 2.

Q.352 - And so can you tell me what the forecasted usage is for each of these services -- Schedule 1 services for the test year?

MR. PORTER: Schedule 1 is the top section. If you look at long-term firm -- long-term firm point-to-point usage is in row 11. Zero 11. And for network the usage, you know, based on the billing determinants is in row 26. So for the test year it is the column that says proposed rates 2008-2009. And as I indicated earlier with respect to short-term firm and non-firm, we do not forecast the usage. We forecast the dollars. And that is on line number 7.

Q.353 - How do you forecast the dollars?

MR. PORTER: As I indicated earlier, we look at the history and project that forward. And there is an interrogatory response in here that gives the fine details as to how tat calculation that was performed.

Q.354 - You say you look at the history, the history of --

MR. PORTER: Of short-term firm and non-firm revenues under Schedule 1.

Q.355 - Could you explain how you developed your forecast of usage for each of the Schedule 1 services for the test year?

MR. PORTER: Yes. If I look at -- let's start with row 11, the long-term firm point-to-point usage. The number that was used in a design of the rates that are in place today or that were -- that were in place up until the time of this application was 720 megawatts. And if you go to the next column over that is labelled proposed rates, it is 1,078 megawatts. And if you look at the far right there is a column there that says tab, it says 3.2. So if you were to turn over three pages until you get to a schedule that is called 3.2, the title of that schedule is Long-Term Firm Point-to-Point Reservation Quantities.

So it lists each of the reservations that make up the 1,078. If you look at -- there is the third column from the far right, it is called Proposed Rates 2008-2009, and when we filed this back in May, we -- and provided this information that lists each of these reservations. It shows what the start date is, the stop date and the quantity. And if you add those up they add up to 1,078 megawatts.

And as you can see all of those reservations started -- start prior to the test year and they end after the test year. So it is a simple case of adding up those specific figures. We did not have any information upon which to forecast any additional long-term firm reservations. And given that these are legally binding agreements to pay for these services, we had no reason to reduce the quantity from what is shown here. So I think that covers off the long-term firm point-to-point reservation usage.

If I could move onto - or go back to that Schedule 1.0 and row 26, it is talking about the network integration or the terminology here is 12 ncp, but that is the -- that is the billing determinant that we use on network service. So that measure, if you look under the column that says Proposed Rates, it says 2,352. And if you look at the far right it says tab 3.3. So if you go over to Schedule 3.3, this shows the history of network service usage and then the proposed rates. And the forecast of the NB Power number as I recall was based on an average of the three years of history that are showing there -- sorry, it was three years of history that we had at the time that we were doing the rate design. An average of the three year's history escalated by 2 percent.

Now the remaining -- well I guess that's it for the usage, because the short-term firm and non-firm revenues, we took the history of revenues from those categories of Schedule 1 and looked closely at more recent revenues. And there is an interrogatory that details out how that was done, but we had the history and I think we largely took the more recent revenue figures and used those to forecast the test year revenues.

Q.356 - Thank you.

MR. THERIAULT: At this point, Mr. Chairman, I would ask Ms. Hennick to distribute another document that I prepared, It is simply appendix under tab 5(a) dealing with the May 1st or exhibit A-1. It is under tab 5(a). There is an Appendix A, which is entitled, Cost Allocation and Rate Design for Schedule 2 Service -- sorry, yes, Schedules 1 and 2 Service.

Q.357 - Now, Panel, when I look at this cost allocation, and correct me if I am wrong, I would interpret the process on this page as taking the cost defined to be Schedule 1 and 2 costs and allocating them to various services in Schedules 1 and 2? In other words, the cost of services defined for each schedule in this cost allocation is nothing more than allocating the defined cost to various services under each schedule?

MR. PORTER: I am not sure if I could accept that exactly as worded. But I will put it in my words you tell me if that is what you are asking for.

Q.358 - Sure. I will tell you if I understand what you are saying.

MR. PORTER: We have taken the respective revenue requirements and allocated them to the two fundamental services that are provided under the tariff, which are point-to-point service and network service. And then as you can see from rows 17 to 23 within point-to-point service, we have products or services, whichever you want to call them, that are in various increments -- various lengths. And so being yearly, monthly, weekly, daily and hourly with the daily and hourly each being available on both on-peak and off-peak versions. And so once we have done the allocation of the cost to each of those two services, point-to-point versus network, we go through a series of calculations to take them -- take that cost of service down to create the rates for the specific -- I will call it sub-services, within point-to-point.

Q.359 - But is it not true that you are taking the cost defined to be Schedule 1 and 2, cost and allocating them to various services of Schedule 1 and 2?

MR. PORTER: Yes, we use that term, services, in many different ways here. But I would certainly accept that usage, yes.

Q.360 - And has the NBSO ever done a cost allocation study in order to ensure that the defined cost charged to Schedule 1 services are actually incurred to provide these services?

MR. MARSHALL: There is not -- we are not aware of any cost of service to break out Schedule 1 services to the individual sub-services, whether it is hourly, daily, monthly, on-peak, off-peak. There is an accepted methodology called the Appellation Pricing Methodology that is utilised in FERC 88 tariffs all over North America that applies and breaks down service on a monthly, weekly, daily, hourly basis. That is what this is based on. So this is an industry standard methodology of breaking out Schedule 1 service from a yearly basis to an hourly basis. So that somebody can buy it in different increments. It is still the same service. It is simply about the term at which you buy that service, you pay a different price for the term that you buy it at. But it is the same service. It is not different services.

Q.361 - Then I guess how would you know that the cost of providing Schedule 1 services is for the proposed rates for '08-'09 is nine million, one hundred and thirty-two thousand and change?

MR. MARSHALL: Because that is the cost of the total NBSO budget less -- the actual revenue requirements is at line 6, which is the total budget, NBSO operations, expenses. So the 9,132,779 is the budget forecast total cost. You subtract the miscellaneous services and you get a revenue requirement that you then calculate the rates on. That's the total cost of operating NBSO net of miscellaneous revenues. That total cost is the cost of service, of providing scheduling, system control and dispatch, which encompassed all of the planning, all of the operating, all of the -- if you want to call them sub-services, all of the activities that are done by NBSO are all rolled up into that one budget. And it is one service, Schedule 1 service.

Q.362 - So there is -- in that amount there is no cost for Schedule 3 service or Schedule 5 service or Schedule 6 service?

MR. MARSHALL: That's correct.

Q.363 - I would like to look at the Schedule 1 revenue requirement, also called I believe the cost of service. Now in so far as I can determine based on the evidence this revenue requirement was filed three times under the evidence in support of the interim rate application, in the evidence for the rate case filed on May 1st 2008, and in the clarification of tariff changes document filed on July 29th 2008. Would that be a fair statement?

MR. PORTER: Yes, that is correct.

Q.364 - And were there any changes to any part of the Schedule 1 revenue requirement for the test year from the original filing in May to the clarification filing in July?

MS. WEST: No, there are no changes.

Q.365 - So over a three month period from May 21st to July

29th there was no need to change the forecast of expenses for the provision of Schedule 1 services?

MS. WEST: That is correct.

MR. MARSHALL: That's a different question, okay. Ask the question again, we will get it straight.

Q.366 - Which one would you like me to ask again?

MR. MARSHALL: Whatever one you want, but just ask your question, we will try to get it straight, because the last one didn't relate to the first one, at least in my mind it didn't.

Q.367 - Well I asked the question, now I will ask it again. The question was that over a three month period from May 1st to July 29th there was no need to change the forecast of expenses for the provision of Schedule 1 services.

MR. MARSHALL: The forecast of expenses for Schedule 1 service is based on the proposed rates, which is the budget that was filed on May 1st, the total number 9133. that did not change. So the basis on which Schedule 1 service was applied for and the basis on which Schedule 1 was asked for an interim for July 1st was based on the exact same numbers that were filed May 1st.

Now your question isn't -- is it the basis of which we are applying and doing the tariff, you are asking about a forecast. If your question is did our forecast of what we will spend in the year change, then the answer is yes. But if the question is the basis upon which you are applying the rates, did it change, the answer is no. And that's why if you look -- and again, Mr. Theriault, just in the -- in A-5, the clarification document, on page 10, there is a revised table 1.

Q.368 - Sorry?

MR. MARSHALL: In A-5, page 10 --

Q.369 - Under which tab?

MR. MARSHALL: Of tab -- revised rates and charges, on page 10 --

Q.370 - Yes.

MR. MARSHALL: -- there is a table 1 revised. On that same document on page 8 was the original table that was filed May 1st. So the original table filed May 1st and the revised table filed the end of July, the column under test year number 1 and July 1st ink which is column number 2, those two columns are identical with the exception of an error correction that was done on line 14. The additional information filed the end of July is the forecast column 2008, '9, June 2008 forecast. Now you can see from those two columns the application for rates for Schedule 1 in the interim application and that we would ask that that continue on for the rest of this year is based on column

2. That's the application number. The actual forecast having given real information to the end of June are forecasts of what we think is going to happen for the rest of the year is in column 4 and they are different.

Q.371 - Okay. I'm not sure if that's as clear as mud, but I will try it a different way. In schedule -- if you look at table 3 which is on page 14 I guess --

MR. MARSHALL: Yes.

Q.372 - Now you would agree that that -- there has been no changes to that Schedule 1 cost of service from May to the clarification filing in July?

MR. MARSHALL: There have been no changes to that cost of service in the application.

Q.373 - Right.

MR. MARSHALL: But there have been changes to what that real cost might be given that we have got six months of actual information.

Q.374 - But I guess what I am wondering is this document was filed in May and it was also filed as part of the July evidence, and the table, table 3, is identical.

MR. MARSHALL: Yes.

Q.375 - So there have been no changes in that table.

MR. MARSHALL: That's correct.

Q.376 - So can you conclude that the exercise of forecasting costs did not produce any significant errors to date?

MR. MARSHALL: At that point in time based on the forecast, having three months of actuals and knowing where it was, there wasn't a significant enough change to alter the forecast -- to alter the budget to say that's the basis at that point in time.

MR. THERIAULT: Thank you. Mr. Chairman, just trying to get a handle on timing on how far the Board wishes to go for today, because --

CHAIRMAN: Would it be a safe assumption that there is not much chance of you finishing today?

MR. THERIAULT: Absolutely not, unless we are going to sit here all night.

CHAIRMAN: Well the Panel has been here for a long time. It's now 4:00 o'clock. So I think the next convenient time to finish up -- perhaps you are finished with an area now and if that's the case we will break now, but if you want to finish off this area of questioning that might be appropriate.

MR. THERIAULT: I am, although there are -- as part of my cross-examination for tomorrow and just so that we are not stalled, I intend to hand certain forms out to the Panel to go through some of the evidence as filed, so it could be in a form that I can make sense of myself, and perhaps if I were to hand that out now and then the Panel could look at it overnight and maybe be prepared. I'm not trying to trick anybody.

CHAIRMAN: There is nothing like homework, is there?

MR. THERIAULT: Well --

CHAIRMAN: Why don't you hand that out. Is it your intention to give it to all the parties and to the Board at this time as well?

MR. THERIAULT: Yes. Well I can give it to the Panel tonight and then introduce it tomorrow during the cross-examination so no one gets confused.

CHAIRMAN: Sure.

MR. THERIAULT: Okay. And I would propose handing it out the Board tomorrow and if any other parties want it tonight -- it's a blank form, probably won't make much sense except for the Panel members. So --

CHAIRMAN: All right. Other than handing out this information to the Panel and to the parties, then you don't have any further questions at this point in time on the issues. This would be a convenient time to break then.

MR. THERIAULT: Yes, it would.

CHAIRMAN: All right. Then we will adjourn until 9:30 tomorrow morning.

(Adjourned)

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

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