New Brunswick Board of Commissioners of Public Utilities

Hearing

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

Delta Hotel, Saint John, N.B.
December 19th 2002, 9:30 a.m.

CHAIRMAN: David C. Nicholson, Q.C.

COMMISSIONERS: J. Cowan-McGuigan
Ken F. Sollows
Robert Richardson
Leon C. Bremner

BOARD COUNSEL: Peter MacNutt, Q.C.

BOARD SECRETARY: Lorraine Légère

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CHAIRMAN: Does the RFF have any preliminary matters?

MR. HASHEY: Mr. Chairman, Merry Christmas.

CHAIRMAN: Merry Christmas.

MR. HASHEY: We will have undertakings hopefully at the break. We are scrambling to get them done. Seeing your stockings in front of you reminds me of a very short story where the applicant or the plaintiff in a lawsuit's solicitor sent the judge $10,000 in a nicely unmarked envelope but with the name of the plaintiff on it. The defence sent the judge $15,000 in a nicely marked envelope.

The judge, after giving due consideration, returned $5,000 to the defence so they would be operating on a level playing field.

CHAIRMAN: Is that a lead into something, Mr. Marshall?

MR. MARSHALL: Actually we do have that level playing field undertaking you --

CHAIRMAN: I thought so.

MR. MARSHALL: -- requested yesterday.

CHAIRMAN: Just a moment while I get JDI's exhibit here. Go ahead, Mr. Marshall.

MR. MARSHALL: Yes. This is undertaking number 42 at page 1757 of the transcript where yesterday Chairman Nicholson referenced the White Paper, the issue of level playing field, is it specifically the electricity market or all markets, and find other references in the White Paper.

CHAIRMAN: Well, I didn't mean to limit it just to the White Paper.

MR. MARSHALL: Okay. Fine. There are no specific other references in the White Paper to level playing field. There is in the Minister's statement on the future of NB Power at page 5 of the Minister's statement, talking about commercialization of NB Power.

It says as NB Power has moved to a level playing field in a more open competitive marketplace it must operate on the same basis as other commercially driven utilities and other energy companies, including gas companies, oil companies, the whole energy market. That is one reference.

But in the White Paper itself there is no specific reference to level playing field. But there are implied references at different places in the White Paper.

Specifically at page 2, section 1.2.2 in the policy goals, with a goal to promote economic efficiency and energy systems and services, it states "New Brunswick's geographic location provides a strategic advantage to compete with utilities, refiners and energy distribution companies in surrounding jurisdictions. However changes to the marketplace require examination of the taxation, governance and perhaps even ownership regimes to achieve the maximum economic efficiency that will allow New Brunswick companies and utilities to compete effectively in both the domestic and export markets."

At other points in the White Paper there are references to proper pricing, fuel selection. In the section on natural gas at section 3.2.4 it states -- it is page 37 of my version. But I think there is a page, one page difference in the filing.

CHAIRMAN: 36 in this.

MR. MARSHALL: So section 3.2.4, "Market-based fuel selection", in the chapter on natural gas, it states "For a competitive market to be efficient all buyers and sellers must be free to make rational economic decisions. This in turn depends on equal access to accurate, comparable and timely information that is relevant to the purchasing decision."

There is a similar statement related to heating oil. Again for a competitive market to be fair and equal -- this is in section 3.3.3. -- all buyers and sellers must have information that they need to make rational economic decisions.

And again the rational economic decisions I think imply -- go back to the overall goal of achieving economic efficiency which relates to all energies, not just electricity.

And in the chapter on energy efficiency at section 3.4.4.3, which is on page 53 of my version, there is a section, price signals -- accurate pricing that informs customers about the true embedded cost of service and time of use cost for consumption is critical for consumers in making economically rational decisions about energy efficiency.

And just over the page at section 3.4.4.3.3 on fuel switching, Many end use applications of energy such as heating and hot water can be provided through competing energy forms including electricity, oil or natural gas.

So that the objective of leveling the playing field is not specifically related in -- the reference in the White Paper and the electricity is related to wholesale electricity market.

But the overall government policy objective is not specifically for electricity. It is for proper pricing of electricity relevant to other fuels in the marketplace for the overall economic efficiency of supply of all energy.

CHAIRMAN: Commissioner Sollows just pointed out to me something I will ask a question about. And that is time of use rates which are specifically stated in the White Paper.

MR. MARSHALL: Yes, they are. I believe they will be dealt with. I think we are preparing time of use rates. I can check with Mr. Bhutani at the break. But they are under development and to be available to be offered to customers next year I understand.

CHAIRMAN: In 2003?

MR. MARSHALL: Ms. MacFarlane just says thinks they have been delayed till October. They should be ready for

October of 2003.

CHAIRMAN: Yes.

MR. MARSHALL: That is the current information I have.

CHAIRMAN: Well, I guess you have confirmed what I thought, is that the White Paper was not terribly specific in reference to competition among energy sources.

The Minister's statement in the house was the first time that I recollect any direct reference to that at all. And to the best of our knowledge there has been nothing subsequent to that.

And Mr. Knight will tell me differently during the break if there has been. So it is dependent really on the legislation --

MR. MARSHALL: Well, I guess it could be.

CHAIRMAN: -- what the legislation says.

MR. MARSHALL: Certainly I guess this is public information that I could find. Certainly in my discussions with government officials relative to electricity pricing and movement, it is very much on their mind that this is competition among all fields.

CHAIRMAN: Well, that has changed, what is on their mind over the last 10 months. I will finish the discussion with that question. But thank you, Mr. Marshall.

Mr. MacNutt?

MR. MACNUTT: Thank you, Mr. Chairman. Good morning, Panel.

CROSS EXAMINATION BY MR. MACNUTT:

Q. - MS. MacFarlane, would you please get out your evidence A-2, tab 4, and initially we will turn to page 7. I will just repeat that. A-2, tab 4, at page 7.

MS. MACFARLANE: Yes, I have it.

Q. - And we will stay with your evidence for a few questions here, so you can leave it out. At lines 6 and 7 of page 7 of your evidence you state, "The amount of total existing debt including short-term and long-term for the transmission business unit begins with the asset base as at April 1, 2001." Is that not correct?

MS. MACFARLANE: Yes.

Q. - Now please turn to page 3 -- table 3, excuse me -- on page 8 of your evidence.

MS. MACFARLANE: Yes.

Q. - This table computes the "attribution of existing debt to transmission", is that correct?

MS. MACFARLANE: That's correct.

Q. - Now at line 6 of that table the transmission unit asset base at April 1, 2001, amounts to $316.8 million, correct?

MS. MACFARLANE: Yes.

Q. - Now would you please turn to NB Power annual report for 2002 which is in exhibit A-5 at tab 4, and we are turning to page 34.

MS. MACFARLANE: Yes.

Q. - The total assets -- on page 34 the total assets for 2001 are indicated as $3.298 billion, is that not correct?

MS. MACFARLANE: That's for the year ended April -- or March 31st, 2001, yes.

Q. - Correct. And you would confirm that the assets amounting to $316.8 million are included in this total?

MS. MACFARLANE: Yes.

Q. - Would you accept, subject to check, that the $316.8 million represents 9.6 percent of the $3.298 billion?

MS. MACFARLANE: I would just like to return to my previous answer for a moment. I think the item on line 5, deferred liabilities, is not included in that total. I think deferred liabilities is part of the item on page 35, the next page of the annual report, under Other, 33 million for the year ended 2001. So line number 5 is not included in the total at page 3.4.

Q. - Okay. Thank you. But would you agree that that percentage is correct, and I will just give it to you again. Would you accept, subject to check, that the $316.8 million represents 9.6 percent of the 3.298 billion?

MS. MACFARLANE: The calculation is correct, yes.

Q. - Now you would agree with me that the applied for capital structure calls for 65 percent debt and 35 percent equity.

MS. MACFARLANE: Yes.

Q. - Would you also accept, subject to check, that 65 percent of 9.6 percent is 6.24 percent.

MS. MACFARLANE: Okay. Subject to check.

Q. - Yes. Would you please turn back to table 3 at page 8 of your evidence --

MS. MACFARLANE: Yes.

Q. - -- and you would agree with that the percentage of long-term debt attributed to transmission is 6.89 percent?

MS. MACFARLANE: Yes.

Q. - Would you please explain why the percentage of long-term debt attributed to transmission is 6.89 percent rather than the 6.24 percent we just calculated?

MS. MACFARLANE: Subject to check, I believe there would probably be two differences. One would be the small amount that we have referred to on line 5 which is not in the 3.298. So that would be part of it, I would suspect. The other issue is that the attribution of debt is done on issue date rate, not on statement date rate. And I would suspect that would have a bearing on it as well.

But I will have to check that to see that in fact that is the difference.

Q. - Would you do that for us, please --

MS. MACFARLANE: Yes, I will.

Q. - -- as an undertaking. Do you agree that the attribution of debt by taking the transmission unit asset as a percentage of the total assets would be fair?

MS. MACFARLANE: Except that the attribution of debt we believe must be done at issue date rate, and as we indicated yesterday, that is because that is the amount of cash that was available from the bond issue at the time that there was an investment made in the assets. So in order to properly ensure attribution of and collection of the principal related foreign exchange, the attribution of debt has to be at issue date rate.

One of the undertakings, Mr. MacNutt, that we will be delivering after the break deals with that as well, the issue of ensuring that the attribution of debt and the effective cost of interest does collect the principal related foreign exchange.

Q. - Thank you. Now, Ms. MacFarlane, in response to a question asked by Mr. Bremner on Thursday of last week, and I think it was at page 1267 of the December 12th transcript, you stated, "The intent here is not to hire more people as we go with this new structure." Do you remember making that statement, or perhaps you could look it up.

MS. MACFARLANE: Yes, I do.

Q. - Were you speaking of NB Power Transmission or NB Power the integrated utility, when you gave your response?

MS. MACFARLANE: Frankly the concept applies to the whole restructure.

Q. - Now Mr. Lavigne, in the response to the Province of New Brunswick IR-28, which is in A-4, in -- perhaps you had better turn it up because we are going to deal with some numbers and I will give that again. Exhibit A-4, PNB IR-28 at page 314.

Now in subsection 6 which is a table at the top of page 314 it's shown that the number of employees will increase in 2003 by ten employees, to 302 from 292 in 2002, is that not correct?

MR. LAVIGNE: Yes, that is correct.

Q. - Now in your evidence in exhibit A-2 in table 7 on page 11, if you would just turn to that. I will give that again. Exhibit A-2, Mr. Lavigne's evidence, page 11, table 7. Do you have that?

MR. LAVIGNE: Yes, I do.

Q. - Thank you. The forecast cost of labour and benefits increases by $1.8 million in 2003 compared with 2002, is that not correct?

MR. LAVIGNE: Yes, that is correct.

Q. - Would you please advise the Board how much of this increase relates to wage increases and how much relates to the additional ten employees?

MR. LAVIGNE: A significant portion of that would be as a result of the signing of a labour agreement which had expired towards the end of 2000. I don't have the specific number but I believe the labour agreement translates into about $1.2 million of that -- 1.2 to 1.3 million dollars of that particular increase year over year.

MS. MACFARLANE: If I might just add as well, Mr. MacNutt, that the dollar value of labour in 2002 here includes -- the collective agreement had expired, but the accrued estimate for what that labour agreement might lead to during the collective negotiation period was accrued in corporate, not in the business unit.

So there would have been an accrual for transmission for the period prior to the collective agreement being signed and included in the year ended 2002, but it is not in these figures, it's in the corporate figures. These figures should have reflected it for purposes of the evidence, but they didn't.

So the comparison is larger than -- appears to be larger than it actually is, because there is an accrual for transmission labour in the corporate figures. We keep it in corporate until the collective agreements are signed so as not to reveal what our estimate for the settlement will be. But we should have included it in transmission for purposes of the estimate -- the evidence.

Q. - What was the percentage increase in the recent agreement?

MR. LAVIGNE: Overall I think the average was a little over two percent per year. I think with respect to this you are looking at -- it looks like an approximate 8.4 percent increase 2002 to 2003. Of that 8.4 I would estimate a little over six percent --

Q. - Is that for the --

MR. LAVIGNE: -- that would be contributed to this labour agreement.

Q. - For wage increases?

MS. MACFARLANE: Yes. And the reason why the numbers appear to show a six percent increase when in fact the signed agreement, the all-in cost signed agreement, is a little over two percent is because, as I say, the accrued amount prior to signing for the year 2002 is not reflected in transmission. It's in corporate. And we did that so as not to reveal what our thinking was about the ultimate settlement, but it should have been allocated to transmission for purposes of this evidence and wasn't.

Q. - How much was the accrued amount attributable to transmission?

MS. MACFARLANE: I don't know the amount but we can get that for you at the break.

Q. - Would you do that for us, please?

MS. MACFARLANE: Yes.

Q. - Now with respect -- back to Mr. Lavigne, I guess. With respect to OM&A expenses for NB Power Transmission what improvements have been introduced in recent years to reduce such expenses?

MR. LAVIGNE: As part of the Stone & Webster study there is a recommendation to look at reliability centred maintenance. We instituted a pilot project, I believe it was in the fiscal year 2000/2001. As a result of that pilot project we are anticipating to go forward with that initiative. The pilot project looked at certain infrastructure in the terminal yards and we as a result of that pilot project will be going further afield to look at a broader infrastructure. This is a multi-year project and as a result of it we suspect that in future years we will see some gains from that particular initiative.

Q. - And how many years is it expected to last and roughly what impact would it have? Can you give us an approximation of the expected --

MR. LAVIGNE: I don't have an approximation. I suspect the project would probably be in the three to five year range. Stone & Webster quoted some figures in their study of ten to 15 percent reductions. I'm not sure if that's reasonable. I think that depends on the utility and the infrastructure, the situation, the environment.

Q. - Their estimate was ten to 15 percent -- percentage of what?

MR. LAVIGNE: I believe it would be just a portion of the OM&A directly related to the maintenance, i.e., a reduction in that particular component of the OM&A.

Q. - That's what Stone & Webster recommended. What in fact has NB Power instituted along those lines by way of implementing programs that will lead to say --

MR. LAVIGNE: Can you clarify that statement? I'm not sure --

Q. - Well you have cited that Stone Webster said if the programs would be implemented there would be what, ten to 15 -- you gave me a percentage.

MR. LAVIGNE: Yes. Those were the figures they were quoting in the study which was ten to 15 percent.

Q. - 10 to 15 percent. Now you say that NB Power in fact has implemented some of the Stone & Webster recommendations, is that correct?

MR. LAVIGNE: We are in the very preliminary stages of RCM, i.e., we have done a pilot to investigate if there would be any value with going --

Q. - Have you adopted 100 percent of what Stone & Webster have recommended or are you being selective in your pilot?

MR. LAVIGNE: We have undertaken a large majority of the recommendations within Stone Webster. I couldn't say for sure whether we have adopted a hundred percent of the recommendations.

Q. - What specific efficiency programs have you implemented and what have the dollar savings been over the last several years?

MR. LAVIGNE: I'm sorry. Could you repeat the question?

Q. - What specific efficiency or cost reduction efforts have NB Power made in the transmission area of the company, and what have been the specific dollar savings? Let's go back two years and project for three years -- well since -- or, if you like, the parameters for the question would be since you -- the transmission business unit has been created.

MR. LAVIGNE: Looking at the Stone & Webster study I think in actuality we probably incurred costs. If you look at the study, the premise to the study was to look at the infrastructure and what Stone & Webster found was that transmission has a very old infrastructure in the low voltage area. This has resulted in increased costs in both the capital program and the maintenance program in order to compensate for the aging infrastructure.

So at this stage, coupled with the fact that it's a multi-year program, you know, three to five years, at this stage costs are actually increasing in order to deal with the recommendations which Stone & Webster put forth.

Q. - So you aren't able to identify for me a point-by-point program that is currently being implemented to achieve identifiable cost savings arising out of what Stone & Webster suggested? There is a general pilot program is what you are saying?

MR. LAVIGNE: On the RCM side, yes. And again as I mentioned, this is in the very initial stages. So I would suspect we are not seeing much in the way of benefits at this stage.

Q. - Even though --

MR. LAVIGNE: Going forward I suspect we will.

Q. - Yes. Even though it's at the pilot project stage have you identified target benefits expected to be achieved?

MR. LAVIGNE: We only looked at a fairly small cross-section of the infrastructure. So no, we did not.

Q. - Now, Mr. Lavigne, we think we have noted a small discrepancy in some of the data presented in your evidence. So perhaps you could turn up your evidence, if you have it. It's A-2, tab 4, at page 1 obviously of your evidence. And I want to go initially to table 4 on page 8 of your evidence.

MR. LAVIGNE: Yes, I have it.

Q. - Now in table 4 on page 8 of your evidence at line 2, where accumulated depreciation in 2003 it is shown as $312.6 million. Correct?

MR. LAVIGNE: Yes.

MR. HASHEY: Mr. Chairman, I think there was a corrected table filed in this matter in A-28, that we probably should work from. Maybe that is what Mr. MacNutt is working from. I just wanted to make certain.

MR. LAVIGNE: That particular number would be the same, but --

MR. HASHEY: Yes. Some of the numbers are the same.

MR. MACNUTT: Yes. A-28 is a correction to table 4, however, the numbers I will be referring to, I am quite certain, have not changed.

MR. HASHEY: Sorry, Mr. MacNutt.

MR. MACNUTT: No, that is fine. Thank you.

Q. - It just so happens that in table 4 at line 2, the accumulated depreciation in 2003 is $312.6 million both in the original table and in A-28. Is that not correct, Mr. Lavigne?

MR. LAVIGNE: Yes, that number has not changed as a result of that revision.

Q. - Thank you. Now if you would turn to page 10 of your evidence where table 6 appears. In line 12, forecast amortization for 2004 is shown as $18.4 million. Correct?

MR. LAVIGNE: Yes, that is correct.

Q. - Now if we add the 312.6 million from table 4 and the 18.4 million from table 6, we arrive at a total of $331 million. Correct?

MR. LAVIGNE: Subject to check on that math?

Q. - Yes.

MR. LAVIGNE: I suspect what needs to be factored in there is --

Q. - Well perhaps I will go through so there is a logical progression on the record.

MR. LAVIGNE: Certainly.

Q. - Now if we return to table 4, we find on line 2, the total accumulated amortization for 2004, of 327.3 million. Correct?

MR. LAVIGNE: Yes, that is correct.

Q. - This means there is a discrepancy of $3.7 million between the two tables. Would you please explain this apparent discrepancy?

MR. LAVIGNE: I suspect the discrepancy would be related to retirals.

Q. - To retirements?

MR. LAVIGNE: Retirals.

Q. - Which are?

MR. LAVIGNE: The retirement of assets.

Q. - Oh, okay. Would you elaborate for the benefit of the Board?

MR. LAVIGNE: Yes. When the retirement is taken out, that reduces the accumulated amortization. Thus the difference between the two tables.

Q. - Okay. I would like you to explain it in terms of retirement of what.

MR. LAVIGNE: It would be the retirement of a particular piece of infrastructure. I.e, a component of a transmission line or a component within a terminal yard. I.e., a specific asset within the transmission system would be taken out of service. It has reached its useful life.

Q. - And what happens to the value of that as shown on the books at that time?

MR. LAVIGNE: Well any cost related to that particular asset would be removed. I.e, from the installed cost base and the accumulated amortization. I.e, it is not inservice and it is not reflected in the cost base.

Q. - Thank you. Now, Ms. MacFarlane, I would like you to turn to page 35 of the NB Power annual report as of March 31, 2002 and for reference that is exhibit A-5 at tab 4.

MS. MACFARLANE: Yes, I have it.

Q. - Thank you.

MR. RICHARDSON: Could you give that reference again?

MR. MACNUTT: Yes, exhibit A-5, tab 4. NB Power annual report year ending March 31, 2002, page 35.

Q. - Under the heading "Long-term debt", the first line reads, "Debentures and other loans, $2.53 billion." Correct?

MS. MACFARLANE: Yes.

Q. - If we add the current portion of long-term debt included in current liabilities, in the amount of $719 million, we have a total for long-term debt of $3.249 billion. Correct?

MS. MACFARLANE: Yes.

Q. - Now the second line under the heading "Long-term debt" readds "less sinking funds". And in the amount of $359 million. Correct?

MS. MACFARLANE: Yes.

Q. - Thank you. Would you accept, subject to check, that sinking funds represent approximately 11 percent of the total long-term debt of 3.249 billion?

MS. MACFARLANE: Yes.

Q. - Now I would like you to turn to exhibit A-4, PNB IR-28, which is at page 316. I will give you that again. A-4, PNB IR-28 at 316.

MS. MACFARLANE: Yes, I have it.

Q. - Yes. I would like you to go to subsection 9(3) on page 316.

MS. MACFARLANE: Yes.

Q. - And it states there under the heading "sinking fund". No withdrawals are made in 2003. In subsequent years withdrawals are made as debentures mature. Is that correct?

MS. MACFARLANE: Yes.

Q. - The instalments are made on existing and new issues at 1 percent debt principal. Do you see that?

MS. MACFARLANE: Yes.

Q. - Now am I correct in my understanding that you confirmed that that principal of providing 1 percent instalments to Mr. Nettleton on I think it was the end of last week, December 16th?

MS. MACFARLANE: I am sorry. Could you say that again?

Q. - Do you remember confirming that 1 percent instalment to

Mr. Nettleton during cross examination last week?

MS. MACFARLANE: Yes.

Q. - Thank you. Now I would like you to turn to table 5 of your evidence at page 12. That is A-2, page 12 of Ms. MacFarlane's evidence. And I am going to go to line 11.

MS. MACFARLANE: Yes.

Q. - So on table 5 in line 11, you find a forecast at March 31, 2003 for debentures and other loans in the amount of $2.255 billion. Is that correct?

MS. MACFARLANE: Yes.

Q. - Thank you. And at line 13 in the same table you find a forecast at March 31, 2003, less sinking funds in the amount of $413.8 million?

MS. MACFARLANE: Yes.

Q. - You would accept, subject to check, that the forecast for sinking funds represents approximately 18 percent of long-term debt?

MS. MACFARLANE: Subject to check.

Q. - Yes.

MS. MACFARLANE: Yes.

Q. - Now would you please explain both the quantum increase in sinking funds of $54.8 million and the increase in the relative percentage?

MS. MACFARLANE: The percentage that you are looking at in the audited financial statement would have taken the sinking funds and divided them by the debt at the same year end period, translated in US dollars at the statement date rate. For purposes of attributing the debt to the capital structure in terms of matching it against assets on table 5 -- pardon me. In terms of matching it against assets on table 3, and then calculating the interest expense on table 5, we have used the debt translated at issue date rate. And this comes back to the concept that there is a principal related foreign exchange differential that attributes over time. And in order to ensure that we are collecting not just the interest related foreign exchange, but also the principal related foreign exchange, we are attributing the debt at issue date rate.

So on line 11, if you were to look back to table 9 on page 18 in my evidence. It is A-2, under the direct evidence of Sharon MacFarlane. Page 17, table 9. You can see under the column 2003, you will see there is the debt translated at issue date rate and at statement date rate. And similarly in 2004, there is debt translated at issue date rate and at statement date rate.

And we have taken the issue date rate for translation of the foreign denominated debt. And the reason we have done that is that that is the amount of cash that was available to the corporation to invest in plant. And therefore the cost of debt has to be measured against that original amount of cash borrowed in order to ensure that we are including in our cost of debt and in our debt allocation, recovery of both the interest related foreign exchange and the principal related foreign exchange.

So that is why you see a difference in the percentages. The percentage that you calculated out of the annual report was based on statement date rate and the percentage on table 5, page 12 is based on issue date rate.

Q. - That explains the differential in percentages. Why is there a difference in the value?

MS. MACFARLANE: Okay. Is it because -- the difference in the value. Can you give me the two differences in the value again?

Q. - It was 413.8 million less 359 million.

MS. MACFARLANE: Right.

Q. - Which resulted in difference of 54.8 million.

MS. MACFARLANE: Right. And the 359 million is at 2002. The 413 is at 2004. And I believe there is an interrogatory that shows the continuity of that. If you just give me a moment I will find it.

It is in appendix -- or pardon me, binder A-4 on page

323. It is in answer to PNB IR-28 (15). So it is A-4, page 323.

Q. - Thank you.

MS. MACFARLANE: Did you want me to take you through it?

Q. - Sure.

MS. MACFARLANE: Okay. On page 323 you can see that the beginning balance at April 1, 2002 which matches the ending balance March 31st 2002 in the financial statements is 359 million.

And you can see the earnings there, the fact that there were no withdrawals in that year and therefore the growth in the fund to 413 million.

I might just add that the reason for no withdrawals in that year -- because typically we do make withdrawals when issues come due -- is that we were trying to allow the fund to grow in value so that when translated in US dollars it would represent a full hedge against the outstanding 250 million in debt that goes out to 2022 and 2020.

So for that one year, with the Province having frankly to change the debt covenant related, as you can see, the amounts that could have been withdrawn are indicated in the column there, 25 million, 15 million, 25 million and 43 million.

But we reinvested the total of 109 million, did not withdraw it, in order to increase the size of the sinking fund.

Q. - Thank you. Now I'm going to come back to table 4 on page 11 of your evidence, Ms. MacFarlane. And it is entitled "Credit Spread". Are you there?

MS. MACFARLANE: I have it.

Q. - Thank you. Now in a response to A-4, PNB IR-6 you provided a publication by CIBC World Markets dated May 17th 2002 and gave support to the spreads as of that date?

MS. MACFARLANE: Yes.

Q. - In other words that IR was submitted with respect to a question they had on table 4.

Now table 4 in your evidence also gives the spread for Province of New Brunswick for 10 and 30-year bonds, is that not correct?

MS. MACFARLANE: Yes.

Q. - When you subtract the average Province of New Brunswick spread of 43 basis points as shown on table 4, from the average spread of the investor-owned utilities of 134 basis points shown just below it, you arrive at a credit spread of 91 basis points, correct?

MS. MACFARLANE: Yes.

Q. - Now exhibit A-29 is the same publication by CIBC World

Markets with spreads as at December 2, 2002, is that not correct?

MS. MACFARLANE: Yes.

Q. - Now would you please advise the Board as to the 10-year and 30-year spreads for the Province of New Brunswick at December 2, 2002?

MS. MACFARLANE: The 10-year spreads for Province of New Brunswick were 38 basis points. And the 30-year spreads for Province of New Brunswick were 49 basis points.

That was on December 2nd, which is the same date as the updated CIBC report. So the average difference is still 43 basis points.

Q. - Is it possible that that differential would change over time?

MS. MACFARLANE: Yes, slightly.

Q. - So if this is a variable amount, why is it that NB Power is basing its credit spread on a specific number from May 17th 2002?

MS. MACFARLANE: The credit spreads do vary slightly over time depending upon the risk profile and I suppose the current economics. But the relationship between the provincial and the corporate is the issue that is -- the relationship between the provincial, the corporate and the federal is what is relevant here.

If we were to update this table we would see that the provincial credit spread did not change. And it is not likely to change much. It changes slightly but not much. However the corporate spreads have increased significantly between the period of May and December.

So the differential, the spread over Province of New Brunswick is about 40 basis points higher if we use the December 2nd CIBC numbers versus the May 17th, I think it is May, CIBC numbers. But at the same time the Government of Canada's have gone down.

So yes, there is a higher credit spread. But the Government of Canada's have gone down. So overall the effective interest rate is about the same. We did do that check to ensure that we weren't -- given the change in profile, we weren't overstating --

Q. - Now --

MS. MACFARLANE: -- or understating.

Q. - -- that would be a spot check for that particular data?

MS. MACFARLANE: Yes.

Q. - What studies or background checks have you made to determine that that ratio is something that would continue on a long-term basis and could be relied on?

MS. MACFARLANE: I don't believe that on a long-term -- that what we are intending here is a long-term basis. What we are looking for is three years.

And Dr. Morin in his -- one of his safety mechanisms, has put a factor, I believe a 200 basis point factor on the long-term Canada's, such that if they move more than 200 basis points up or down, either the corporation can come back to the Board or the Board can call the corporation back.

Q. - I'm sorry --

MS. MACFARLANE: The safety mechanism doesn't deal with credit spreads. But it does deal with the largest part of the underlying -- the largest part of the factors underlying the interest rate that will be included in our going-in-rates. And that is the Government of Canada's.

Q. - Now if I look at table 5 of your evidence, which is at page 12, and I go to line 5, that is where the credit spread has been translated into dollars. And on that table it represents $20.1 million --

MS. MACFARLANE: Yes.

Q. - -- am I correct?

And that is based on the .91 --

MS. MACFARLANE: Yes.

Q. - -- percentage?

So the problem I have, that .91 translates into fairly substantial dollars. And I have a problem with understanding how we can rely on that .91 spread being consistent and reliable over the next several years.

So I guess the question is -- I have difficulty with reliability. What assurances can you give us by way of explaining what studies you may have carried out to determine the certainty and predictability of that spread?

MS. MACFARLANE: Credit spreads is something that we watch and that the Province watches regularly. We had to pick a point in time number.

I'm thinking that perhaps we can have an undertaking to have Dr. Morin provide some attestation as to the bands within which credit spreads for utilities may typically fall.

And that may provide -- we can provide that when we return on January 6th, some evidence from Dr. Morin. And that may help provide the assurance that you seek.

Q. - Yes. Would you do that please? And have it address the six-month periods that -- you know, six-month time period. Thank you.

Moving on to a different topic, still with you, Ms. MacFarlane, would you please describe in general terms how you arrived at your estimate of the volume of sales for each of network transmission and point-to-point transmission?

MR. PORTER: We responded to that in an IR. But I can say that what we did is we took the historical and projected that into the test year and beyond for the additional year that we have projected in the evidence.

Q. - Would you give us that IR reference? Well, perhaps during the break you could identify that for us. And I will carry on with the sequence here.

MR. PORTER: Yes.

Q. - What is the estimated percentage increase in volume of sales for each service for 2003 and '04 over 2002, '03 approximately? We are not looking for --

MR. PORTER: Those volumes are not in the evidence. We would have to take an undertaking to answer that question.

Q. - Yes. Would you do that --

MR. PORTER: Yes.

Q. - -- an undertaking to provide that --

MR. PORTER: Yes, we will.

Q. - -- percentage increase in volume? Now --

MR. PORTER: Sir, just for clarification then, that is on -- you asked on point-to-point and network service I believe?

Q. - Yes. Volume of sales for each of network transmission and point-to-point transmission?

MR. PORTER: Okay. Yes. We will do that.

Q. - In light of the fact you are giving us an undertaking, are you able to advise as what adjustments were included to reflect the fact that NB Power market structure will change as of April the 1st?

MR. PORTER: That change has no impact on the volumes.

Q. - Why not?

MR. PORTER: The volume -- are we talking about network service? First of all network service is a function of the loads in the province. And we don't project any change as a result of -- by that time period as a result of the implementation of the market.

Q. - Yes.

MR. MARSHALL: I might add to that. The transmission forecast is based on the forecast of loads and usage of the transmission system.

Whether or not participants participate in the market and they buy from competitive suppliers or take it from standard offer service, whatever, has no impact on the volume of load in the system. It still is the same volume of load.

So the market and the competitive supply in the market doesn't influence the volume of the transmission use.

Q. - Your statement is applicable to a network situation, is it not, Mr. Marshall?

MR. MARSHALL: That is correct.

Q. - And what is the situation with respect to point-to-point service?

MR. PORTER: On the point-to-point I can say that in the modeling we did not project any point-to-point service to load within the province.

The point-to-point service is in the projection that are all to external loads. And that is true for both long-term firm and for short-term firm.

And those loads and their usage of the transmission system under the point-to-point service would not be impacted by the implementation of a market in the province of New Brunswick.

Q. - Are you saying that the sales forecast means that there will be no increase or decrease possible over the next three years?

MR. PORTER: No, I didn't say that. I believe the question was what would be the volume increases as a result of the implementation of the market. And my response to that question was that there would be no increase as a result of the market opening.

Q. - Do you expect there to be any deviation from your forecast sales over the next three years? And if none, why? And if, yes, why?

MR. PORTER: Yes. We have -- as in any projection we have made our best estimate as to what the volumes will be. But we don't expect them to be exactly accurate. But I don't see any major deviations from those projections.

CHAIRMAN: Mr. MacNutt, we are more than 50 percent through your cross examination, according to your time estimate. I think this would be a good time for us to take our 15 minute break.

(Recess)

CHAIRMAN: Mr. Hashey.

MR. HASHEY: Thank you, Mr. Chairman, sorry for the delay. We are trying to get as many undertakings done as possible today and we are having good success. If Mr. MacNutt won't add any more --

CHAIRMAN: Don't count on that.

MR. HASHEY: -- it will make it easier. But what I would prefer to do if we could is just answer the one that arose out of a question this morning. And at the conclusion of Mr. MacNutt's cross examination we will put in the rest of the undertakings rather than interfere with what he is doing now.

CHAIRMAN: That would be in 57 minutes I understand.

MR. HASHEY: 57 minutes, we have the clock on. Ms. MacFarlane has one answer arising from a question this morning, I think, and Mr. Porter does as well.

CHAIRMAN: Okay.

MR. HASHEY: So, Ms. MacFarlane, maybe first.

MS. MACFARLANE: Yes. This was in answer to the question if you were to look at the consolidated balance sheet of NB Power at March 31st 2002 and look in the 2001 column, I believe, Mr. MacNutt, you had taken the assets that we had allocated to the transmission business on table 3 of 316.8 million and divided it by the total assets of the corporation at that time and it, I believe you said, was 6.23 percent. And yet we are allocating 6.89 percent of debt, and you had asked why.

If you look at the consolidated balance sheet, which is on page 34 of the corporate financial statements, the annual audited financial statements, the percentage -- the transmission assets over -- the transmission fixed assets over the total property plant and equipment for the corporation is almost -- well, it's 307.8 over 2906. That's 10.6 percent. And multiply that by .65 it's exactly 6.89 percent.

But when you look at the rest of the assets you can see accounts receivable 174 million. None of that accounts receivable belongs to the transmission business unit. That would belong to the distribution business unit. The working -- or pardon me, yes, the working capital for transmission is a very small percent of the corporate working capital. And it's large because of that accounts receivable number.

And for that reason you can't take a straight attribution of the transmission assets in total against the corporation assets in total because the current asset, current liability ratio is different.

I might mention too, just two other minor things. In table 3 I had already said that deferred liabilities, which was on line 5, is not in the asset section of the balance sheet, it's in the liability section.

I would also point out that we have not just included current assets here. We have netted current assets of current liabilities. We are showing working capital. So, again, the current liabilities are not in that 3298 either.

So it's that the minor assets and minor liabilities being the current assets and current liabilities are in a different proportion than the fixed assets are. And the calculation of debt almost entirely matches the calculation of assets, transmission assets to total assets because, in fact, that's what the bulk of the balance sheet is.

Is that clear?

MR. MACNUTT: That's not entirely clear. It's an explanation which is on the record. I wonder if you would find a table which explains that?

MS. MACFARLANE: Yes.

MR. MACNUTT: Thanks.

MR. HASHEY: We thought we rid got of one, we didn't. So let's try again. Mr. Porter, your turn.

MR. PORTER: Pertaining to the question about the projected increases or changes in volumes under the tariff. For network service I have a .9 percent increase.

Q. - Yes.

MR. PORTER: Long-term firm, no change. And for short-term firm and non firm, 1.1 percent. That's a 1.1 percent increase.

Q. - Over what period?

MR. PORTER: That's in the second year of the data shown versus the test year. That's over a one year period.

And just for clarification, the network is a service that's billed out on a non-coincident peak basis, meaning that it's based on the demands at the individual substations of each customer.

Whereas the long-term firm, short-term firm and non firm services are billed out based on the contracted or reserved quantities.

Q. - Is it your opinion that there is little chance that the actual sales for 2003 and 2004 will be significantly different from the forecast? And if not, why not?

MR. PORTER: The forecast is based on our best information. We have in terms of the point to point services, our transmission services administration group is as familiar as they can be with the activities in the region. And base the projections on the point to point service on that basis.

And the network service is largely based on our corporate load forecast. And that, again, that's using the best information available. And we don't anticipate any significant deviation from the forecast. I think if you look at the history of the data, particularly on what we see that the in-province load, the majority of it would likely be on network service. And that in-province load has tended to grow in a relatively stable fashion.

Q. - Yes. Now on to another topic. Mr. Porter, in exhibit A-2, appendix B, which is the NB Power Transmission tariff design at page 16 -- you can turn this up if you would like, but I will quote. Again, A-2, appendix B, NB Power Transmission tariff design, page 16 and I'm going to line 17.

MR. PORTER: Yes, I have that.

Q. - You stated that, "Metering is fundamental to the settlement of all energy flows and some of the ancillary services."

Now later on the same page it is stated that, The NB Power Transmission business unit owns the meters for connection to the wholesale customers and, "Generators are responsible for the cost of providing meters at their connection point to the transmission system." Is that correct?

MR. PORTER: Yes, that's correct.

Q. - Now, Mr. Marshall, in your evidence in exhibit A-2 which is under tab 4 at page 5, line 13 you state, "Net non-coincident demand by delivery point has been selected as the billing determinant for network service. This is because proper interval metering does not exist at all transmission delivery points." Is that correct?

MR. MARSHALL: That's correct.

Q. - Now, Mr. Marshall, what is an interval meter and what is its function in the NB Power system?

MR. MARSHALL: An interval meter is one that can measure the flow essentially in real time. It would be poled every five minutes so that it is possible to measure the amount -- the quantity of energy that flows across that delivery point in five minute intervals. So that you can actually then measure exactly what the 15 minute demand period would be. But you know also exactly which 15 minutes in the month that it occurred in. At many of the delivery points in the system to substations to distribution across the system, there are meters that can measure demand but they cannot -- they basically measure the demand on a thermal basis over the whole month. So you know when the demand occurred for the 15 minutes of demand -- or, excuse me, you don't know when the demand occurred for the 15 minutes. You know what the magnitude is, but you don't know when it occurred. So you don't have a way to allocate it directly against the coincident peak. You only know what it was as a non-coincident peak over that month.

So if we were going to use coincident peak billing and contribution to coincident peak, it would be necessary to have interval meters at every delivery point across the system and they do not exist at this time.

And I would add, this was an issue considered by market design. And market design went through this and looked at the estimates of costs involved and made the recommendation that initially definitely to go forward with non-coincident peak because of the additional cost it would put into the system for no apparent gain.

Q. - So you do have interval meters in your system now?

MR. MARSHALL: Yes. Every large industrial customer has interval meters. A number of the delivery points for Saint John Energy have interval meters. But there are -- there are not interval meters at all of the delivery points to NB Power distribution substations.

MR. PORTER: If I might add to that, that municipal utilities will have interval metering in place by April 1st of next year. That's in response to an IR.

Q. - Now Mr. Marshall, you perhaps don't have to turn this up. But I will give you the reference. In exhibit A-4, PUB IR-74 at page 449, you were asked how many transmission delivery points there were, how many of them have interval metering and asked the cost to upgrade interval metering at all points, is that not correct?

And I will quote you your response, a portion of your response. "The total number of metering points is 372, of which 90 have interval metering. 58 of these interval meters are connected to revenue quality facilities. The total cost to upgrade to revenue quality interval metering at transmission delivery points has been estimated at $10 million." That is the end of the quote.

And you went on to say that the cost would be higher due to the need for additional requirements, correct?

What is an interval meter with a revenue quality facility? And what is its function in the NB Power system?

And just before you answer -- I perhaps haven't asked it quite correct. What I'm trying to understand is the statement you made that "58 of these interval meters are connected to revenue quality facilities."

Would you please explain what you mean in that statement?

MR. MARSHALL: The -- in my -- I'm not the metering expert. But my understanding is that for for instance a large industrial customer or a municipal wholesale customer today, the meters would be an interval meter that is revenue quality, means it meets the standards of Industry Canada, I think it is, but the federal agency that sets the standards for the accuracy of those meters.

In order to meet all of the requirements, there was also the point that the potential transformers that deliver the voltage to the meter and the current transformers that deliver the voltage to the meter also have to be accurate enough to deliver the information on which the meter does its calculation.

And so that that is the point where they will be able to deliver data at revenue quality data, meaning it will meet the standards of Measurement Canada, I believe Mr. Porter said, that set the standards to meet revenue quality.

Q. - Now the question is not restricted to Mr. Marshall. If Mr. Porter has a greater or deeper knowledge of this, it would help.

MR. MARSHALL: Well, he is not a meter expert either. But he may have more knowledge than I do.

Q. - So what is the import of the "revenue" aspect of a revenue quality meter? You have indicated the revenue quality meter meets a certain standard.

Does a revenue quality meter also measure something different than an ordinary interval meter?

MR. MARSHALL: No. The revenue quality deals with the accuracy of the measurement. The revenue quality -- a meter here will still measure demand, kilowatts, measure energy.

So the metrics that it measures are energy flow, demand across a meter. The issue of whether it is revenue quality or not is whether it measures that within a tolerance accuracy within the standards of Measurement Canada.

MR. PORTER: I think I might add that the reason we would have meters not of revenue quality is typically because of metering within what is the vertically integrated utility, for instance between NB Power's transmission system and NB Power's distribution system, where there was not a need to have revenue quality metering, so --

MR. MARSHALL: Or between generators, the NB Power generators and the generation system. And I might add that in upgrading, that the $10 million in upgrading the cost, it is not simply the matter of putting in a more accurate meter which meets the requirements.

The cost is in going in and replacing all the potential transformers and current transformers that are in the system in order to get the information out to the meter. So it is not a simple task just to change a meter.

MR. PORTER: And that is required -- I mean, the hardware, but also the maintenance outage that is required on some of the facilities in order to be able to change out the instrumentation transformers.

Q. - Now Mr. Marshall -- and you perhaps don't have to turn it up, because I'm going to quote. In exhibit A-4, WPS IR-2, page 579, WPS wished to know the cost of installing interval metering at all wholesale customer delivery points.

And in your response you stated "The estimated cost of installing interval metering for the wholesale customers is approximately $1 million."

And you went on to say the cost could be lower depending on the quality of the existing meters. Is that correct?

MR. MARSHALL: Yes. Again as I just explained, the cost is not associated simply with changing the meter. The cost is associated also with replacing the instrument transformers, the current transformers and the potential transformers.

If those instrument transformers are revenue quality then the costs would be lower and there could be some saving. If they are not, then you need to replace the meter and all of the instrument transformers. That is the variability that is referenced there.

MR. PORTER: That estimate -- my recollection is that estimate was based on a typical installation and I believe assumed that the instrument transformers would need to be replaced.

There was no detailed analysis of a site-by-site as to what the actual requirements would be at each site.

Q. - When the wholesale customers are place on acceptable interval metering at a cost of $1 million, will the billing determinant change from net noncoincident peak to another form? And is it your plan to do that?

MR. PORTER: For the purpose of the transmission tariff there will be no change. The intention is to use net non-coincident peak billing. And that will be the case.

MR. MARSHALL: Yes. As Mr. Porter said, it is our plan to continue with net non-coincident peak billing. We think it accurately reflects the usage of load customers in the system, of their usage on the system.

And it is also the same practice that all of the existing customers in the system that are eligible to participate in the market are billed under today.

MR. PORTER: I might point out that there is a discussion on that in the Rudden Report about the fact in addition to the issue of whether or not appropriate meters are in place, there is also the issue that Mr. Marshall just spoke of, the fact that the customers are familiar with being billed for demand on their non-coincident demands.

So administratively and for customer acceptance that continuity is appropriate.

CHAIRMAN: Mr. MacNutt, if I could interrupt?

MR. MACNUTT: Yes. I am, Mr. Chairman, going on to another question.

CHAIRMAN: Explain to me, gentlemen -- and I hear you say you are not a metering expert. But how do you go to time of use rates for your large industrials without that kind of metering?

MR. MARSHALL: Oh, all of the large industrial customers have interval metering. So we can measure large industrial performance on a five-minute basis at any five-minute time.

So we have all the data to be able to look at on-peak, off-peak with those customers.

CHAIRMAN: Okay. My understanding is the it is just the self-generators who would be -- their billing would increase dramatically under the new tariff if you did it on the basis of system peak rather than coincident peak, is that correct, in the large industrial group?

MR. MARSHALL: I believe that supposition that -- well, there is some evidence to that effect. And there will be more evidence related to that.

Whether or not their bill will or will not increase dramatically is a matter of what choice they use. There are a lot of factors involved.

So the issue is using non-coincident peak billing may relate to an increase in cost to some of the self-generators, depending upon their load factor and depending upon the service of transmission they choose, whether it is network or point-to-point. So there are number of variables involved in that.

CHAIRMAN: My understanding, very skimpy as it may be, is that -- and you claim that the large industrial group of customers of NB Power today approach unity when it comes to cost of service and cost recovery.

So that means that within the large industrial group, if what JDI is going to maintain is correct, and there is a subsidy that is flowing from those large industrial users who don't have self-generation over to those who do. Is that a fair comment?

MR. MARSHALL: I don't -- I guess if you are suggesting that in the current rate structure there may be a cross-subsidization between firm industrial customers and the interruptible energy customers who have self-generation -- is that the question?

CHAIRMAN: Yes. That is the question.

MR. MARSHALL: I don't know if it is a cross-subsidization. I think that the current rate structure certainly favors the interruptible energy at times, it is a more cost-based energy on the margin with an adder.

At this time, with oil prices being very high, I would think large industrial customers would say it is not favorable to them. At other times, when there are lower oil costs, it is favorable.

The issue here is what is the cost of the transmission system that they are using in order to deliver the services? And how is that going to affect that service going forward?

And there are possibilities, depending upon the type of service they take, that could increase that cost significantly, depending upon the service they take and depending upon the load factor. I think that is the issue of potential rate shock for the self-generators.

CHAIRMAN: Okay. Thank you, Mr. Marshall. Go ahead, Mr. MacNutt. I'm sure Mr. Nettleton's witnesses will cover that in January.

Q. - Now Mr. Marshall, I'm going to talk about ancillary services. And I would like you to explain to the Board how the transmission provider, in other words Transco, goes about procuring ancillary services from a supplier.

And I want you to be very particular in your answer. In other words, a description of the process that a layman can understand, in the sense that I'm not, and none of the members of the Board are intimately as familiar with the process used for ordering and pricing ancillary services within the current NB Power structure.

So I would like you to go through it in very basic steps. Let's start with who is Transco going to call on April the 1st for ancillary services?

Let's say that Transco wants to take six units of service. Please describe the conversation you would have in the sense that you are representing Transco. Who would you call and what would you ask for? Mr. Porter can answer as well.

MR. MARSHALL: No, we will just -- okay. Well first of all I want to just clarify. On April 1st the system operators at the energy control centre are not going to call generation or somebody to say, who can give me these services at that point in time. What we are talking about is there has to be a contract in place.

Because these are capacity based services and they are forecast, they are predictable as to what is the quantity required because they are needed to supply reliability to the operation of the power system. And those reliability requirements are laid down by the rules of the Northeast Power Coordinating Council, so the system operating group at the energy control centre in Transco know the requirements and forecast what they are.

They can't wait till the day or an hour before to then say where is it going to come from. So there will be a contract between the generation business unit and the transmission business unit --

Q. - Just -- if I can just interrupt you. is there such an agreement now in anticipation of market open on April the 1st?

MR. MARSHALL: No, right at this time there is no official contract.

Q. - When do you expect such to be in place?

MR. MARSHALL: The -- there would be a contract in place prior to April 1st so that transmission has the right to call on the capacity, all of the generation capacity. After it is scheduled to meet load, transmission would have the right to redispatch it in order to procure the ancillary services in the least cost manner. And for the right to call on all of that capacity and to use it to deliver the services they will make a payment.

And the payments are based on the information that's applied in this tariff. So that the transmission will have the right to call on generation. Now if at some point in time it may be through the redispatch or through availability of other generators as they go through the market, they would be able to contract with other entities as well.

But initially in this tariff the application and the rates are on the basis of a contract from NB Power Generation resources to the system operator. That the system operator has the right to call on those resources and redispatch them in order to meet all of their ancillary service requirements to reliably operate the system.

So the system operator will plan everyday what they need and they will give the schedule back to the generators, here is how you are altered now to operate in order to meet the requirements to run the system reliably.

Q. - And what would be asked for on that day to day request? What would the terminology of the request be? Make us familiar with that.

MR. PORTER: For these capacity based ancillary services, it would define typically as Mr. Marshall said on a day ahead basis, say X number of megawatts for regulation service. Y number of megawatts for load following and so on.

MR. MARSHALL: And it would specify that this particular generator is going to be on automatic generation control, so that the system operator would then call the specific operators of the generating facility and say this unit is on control, just to give them notification. But the control doesn't go through the operator of the generator. The control is done directly by the operator of the system at the energy control centre.

MR. PORTER: And I would add that that's exactly what's done today. Under our functionally unbundled status the systems operation people at the energy control centre on a day ahead basis they would look at what the size of the largest contingency, the first and second contingency and that is used to calculate the amount of reserve required. And so that data is sent to the generation marketing group on a day ahead basis and then they build that into their generation plan for the next day, submit their plan to the system operator.

And the system operator looks to say yes, are the appropriate facilities in this plan available to provide the required services to maintain the reliability of the system. And they approve that plan. Or send it back to -- for revision until it's done properly.

MR. MARSHALL: Yes. But just to point, the final decision is made by the system operating group not the generating group. The system operating group have the right to call on this capacity and to use it to meet the requirements. They are the final -- make the final decision.

Q. - Just a moment, Mr. Chairman.

MR. PORTER: Mr. MacNutt, I would like to add just for clarification, that this application, as we have said before, is from a vertically integrated utility and therefore the requirement for an explicit contract between the transmission business unit and the generation business unit was not required. It's really the restructuring and opening of the market of April 1st that leads to the need for an explicit contract between the system operator and the generation.

Q. - And that's what we are trying to understand is that transition. And how you are going to implement that separate company and the requirement for this documentation. That's what we are trying to get you to help us understand.

MR. PORTER: I appreciate that.

Q. - So on that same line who in fact will negotiate the contracts between Transco and Genco?

MR. MARSHALL: The -- initially the contracts, as I see it, will be based on the ruling of this Board on the evidence before it to say what are the reasonable charges for the ancillary services. And that that will be the value of the service in the rates, the capacity base rates that have been calculated that are here. That's the procurement cost from the generator for the capacity. The contract will be based on that value and the out of order dispatch costs as monthly. Those will be the basis of the contract. Those dollars will flow to the generation unit or generation company as restructuring goes forward. And the system operator then on the basis of that will collect money from the customers through the tariff, turn around and pass it on to the generation entity to fulfil the contract.

Now one of the issues, I might add -- I mean, as we go forward this tariff application is the basis of the market in order to start the market place going forward. As the system operator is set up and as the system operator evolves, there is an intention to possibly introduce a market for ancillary services -- or a market for -- certainly for energy imbalance or some services. And this was a recommendation of market design.

So as that -- the market evolves under the auspices of the system operator, if it's possible to introduce market base mechanisms to procure these services, then the system operator will come up with rules for that. And if that results in any changes to the tariff ruling, they will then have to come back to this Board to get approval of those changes to the tariff as we go forward.

But for the initial operating of the market the contract would be based on the final ruling of this Board in terms of the pricing of the services.

Q. - Thank you. Does it -- have -- you mentioned the manner of pricing and you said that the tariff would contain the price and the price on the approved tariff would be applied against the quantity of the service, is that correct?

MR. MARSHALL: The tariff approves rates to be charged to users. So whether they are network customers or a point-to-point customer buying some additional ancillary services or whatever, the tariff defines the rates charged based on usage, which is for network service non-coincident peak load. And the ancillary services will be billed based on that non-coincident peak load monthly to customers. The Transco or the system operator, if it's structured and set up, will be operating and implementing this tariff. They will collect that money from the customers. They will in turn pass that money on to the generation entity who is supplying all of the services.

Q. - Thank you. Now have these -- do you currently have an internal rate that you are using in charging out for the services in light of the fact that you have established a transmission business unit? Is there an internal charging system?

MR. MARSHALL: There -- we can check on that. There had been some calculations done on the cost of these services and some intent to track them but it's not included in the -- it's my understanding and Mr. Porter's as well, it's not included in the current transfer pricing between business units in the model. It's -- that's internal accounting. So that all we can do is take that subject to check -- or an undertaking to see if there in actual fact is a --

Q. - So you are asking the Board to approve a rate which in day-to-day operation would then be used to determine the amount to be paid for the service, is that not correct?

MR. MARSHALL: That's correct.

Q. - How is the Board to arrive at the appropriate rate --

MR. MARSHALL: Based on the evidence --

Q. - -- if we have no information from NB Power with respect to the actual cost and transfer pricing that's being used now?

MR. MARSHALL: The cost of the service as -- in the evidence before this Board now is that proxy unit pricing is a reasonable valuation of the generation costs of the service.

Q. - How will this Board determine whether or not proxy pricing has any relation to practical day-to-day price or is a reasonable price compared to the other methods of pricing the services?

MR. MARSHALL: The proxy unit prices that we have before this Board for the costs of the generation supply are a progression from our analysis of costs in the system. The issue we have is -- to lay out the embedded cost of generation is a competitive issue that I have addressed earlier and that that's why that we do not -- or our generation people do not want us to lay that information out in the public.

Q. - Yes, but the way that the evidence has been presented is that you have given -- suggested that proxy pricing is the way to go. You have given a rationale for it. But we -- the Board does not have it before -- evidence before it to which it can look at to test whether or not proxy pricing is reasonable bounced against the other methods of pricing. Are you able to provide us with anything that would allow us to do that test?

MR. MARSHALL: We could provide some information in confidence to the Board. One such example would be the pricing in the products and services agreement to northern Maine for the ancillary services that are sold to that entity. The development of those rates were based on embedded costs of generation.

And the reason they are confidential is that the generation business unit does not want them made public, so they are confidential in that agreement. We could certainly provide that in confidence to the Board so you would have a comparison of the rates.

Q. - Have you in fact prepared any studies on the other three methods of pricing ancillary services? And if so can you explain them to us?

Said differently, how did you arrive at proxy pricing unless you looked at the other three methods?

MR. MARSHALL: We -- the methodology used for the Products and Services Agreement was an embedded cost calculation. Again we could provide the background calculations behind that in confidence to the Board.

The -- we have not looked at marginal cost methodology or bid-based markets. The reason simply is that a bid-based market could not fundamentally operate in New Brunswick or the Maritime area today very effectively, because of the market power of certain providers in the market, particularly the market power of NB Power Generation in supplying those services.

So it has always been our position that a bid-based market, although efficient in New England or New York or PJM, in very large markets, it is possible to have a bid-based type market that can effectively work. It could not effectively work in New Brunswick. So we have discounted that one as not viable at this time.

Q. - So that is two out of the four?

MR. PORTER: Market Design Committee came to the same --

MR. MARSHALL: Market Design Committee reviewed those as well, came to the same conclusion, that a bid-based market would not be viable because of market power issues.

The second one, the marginal cost pricing again we think undervalues the service completely, if it is just based on the marginal cost of the unit.

And again if -- even through cross examination from Mr. Nettleton of an example, a hypothetical example of two units at different marginal cost, still requires a market.

I mean, it is essentially a bid-type market except that the bid is now at your marginal cost. In this system almost all of the generators in the system will have similar marginal costs for energy. They have different capabilities to move and follow load.

So we just do not see marginal cost on the New Brunswick system as a viable option for pricing ancillary services.

MR. PORTER: And I would add to that we did look at marginal costs, not as an overall approach, but as a component approach, back as part of the unbundling project in '99.

And I worked quite closely with our ancillary generation operations people and had them look through their OM&A records and what not to say really what are the incremental costs associated with having a unit providing automatic generation control versus not providing automatic generation control or any of the other services.

And we were unsuccessful in being able to track or determine or isolate those costs. And we searched the Internet and what not. And we are not able to find any really accurate representation of those marginal costs from any other source either.

So there was that type of study done to look at the feasibility of using such an approach.

MR. MARSHALL: So it brings us back to embedded costs, based pricing or proxy pricing. And those are the two that we have done work with.

And I can say that the embedded cost pricing that we have put -- or excuse me, the proxy cost pricing that we have put forward before this Board in this application comes up with rates that are consistent and similar to an embedded cost of study.

Q. - Thank you. Now the Board sets the rate, assume following the proxy approach, for discussion purposes. How does the Board know that Genco, the separate legal company, will in fact accept whatever price the Board establishes?

MR. MARSHALL: The system operator and the transmission company have the responsibility to run and operate the transmission system reliably under the guidelines and rules of the Northeast Power Coordinating Council and the North American Electric Reliability --

Q. - Yes.

MR. MARSHALL: -- Council.

Q. - I understand that. But Genco --

MR. MARSHALL: And they have the authority to order generators to conform to the requirements to operate in the system.

Q. - That is to provide the service. But how about the pricing?

MR. MARSHALL: The pricing -- if this Board rules in the tariff this is the money that can be collected, then this is the only money that can be collected through the tariff in order to pay for those services.

Q. - What happens if Genco doesn't accept the price?

MR. MARSHALL: I don't think that is an issue. But I think this is a constraint even on -- on the restructuring the Market Design Committee made the recommendations that the tariff provide for the ancillary services and to be regulated in the tariff.

So that through the restructuring, I think part of the agreement of Genco will be that they will have to conform to the tariff.

Q. - Is that in the tariff now? Is that provision in the applied-for tariff or in the rate design?

MR. MARSHALL: It is indirectly in the tariff, where I believe under cross from Mr. MacDougall yesterday pointed to the generator interconnection agreement and that generators would be required to, on a voltage basis, operate at a certain level, and then get compensation for it through the tariff.

I think that that would apply to -- at this point in time, that agreement will be part of the vesting contract agreement between NB Power Generation and NB Power Distribution, that through that vesting contract NB Power Generation will be obligated to supply these ancillary services, and that the contract price will be whatever this Board says.

Q. - Well, you have just mentioned vesting contract. And I have heard that several times over the last several days. What is a vesting contract in the context of a transmission company?

MR. MARSHALL: The vesting contract comes from the recommendation of market design committee for the structure of the marketplace, that the existing generation assets in the system, and they refer to them as heritage assets, that it is the -- they have been built under the regulated structure for customers existing in the system today, and that customers -- market design recommendation is that customers in the system today have the right to continue service from those assets.

And that is consistent with the White Paper which says that customers who choose not to go into the marketplace for a competitive supplier have the right to standard offer service under terms, conditions and prices similar to what they get today.

So in order to ensure that that can happen, there needs to -- the recommendation is that there would be a vesting contract of all of the existing assets to NB Power Distribution from NB Power Generation, that the Minister of Energy would set the pricing of that contract, and that through that contract NB Power Distribution then has access to all the resources in the system in order to continue to deliver the services it needs under standard offer service.

That includes the provision of the ancillary services that are the foundation of the services provided for in this tariff.

Q. - Thank you. Now we have just been talking about what happens on April 1, 2003. Let's go one year further down the road and look at April 1, 2004.

On that date, April 1, 2004 can ancillary services be obtained from anyone else? And if so on what basis? And I mean from a provider other than Genco. And how would those prices be set?

MR. MARSHALL: As I explained yesterday in relation to the discount, the transmission unit, the system operator will in actual fact be out -- if there is an opportunity to procure services at a lower cost than in the contract from generation, they will be able to do that.

And through that they will be able to then pass those savings on to customers through the discounting mechanism for ancillary services. So that will start even April 1st of this year.

Now as we go forward in time, the system operator will have, as recommended by market design, there will be a stakeholder review committee in the system operator structure.

And they will be looking at changes to market rules and opportunities to procure through the market, if it is possible to introduce market mechanisms or to change the process on a go-forward basis, the independent system operator will make those decisions.

And if they relate to a change in the tariff, they will then have to come to this Board to make those changes on a go-forward basis.

MR. PORTER: Just for reference there, what Mr. Marshall has just indicated in terms of the treatment of lower cost due to competitive acquisition of such services is addressed in response to a supplemental from Province of New Brunswick. It is supplemental number 1.

Q. - Thank you. Now Mr. Lavigne, in exhibit A-5 -- and I don't think you have to turn it up, because I'm just going to refer to it.

In exhibit A-5 under tab 9 of the NB Power responses to IR's, there is a document prepared by Deloitte & Touche entitled "New Brunswick Power Corporation, Allocation of Overhead to Capital Projects Corporate OM&A Cost to Business Units" dated August 2001.

Now it is my understanding that this study allocated corporate expenses to the various operations of NB Power including transmission, is that correct?

MR. LAVIGNE: Yes. That is correct.

Q. - Now this study and the allocations I assume were relied upon and used by NB Power witnesses in preparing their testimony for the present hearing.

Am I correct in that assumption?

MR. LAVIGNE: Yes. That is correct.

Q. - The allocation methods are described in the study. However the starting point is the current level of corporate expense, is it not?

MR. LAVIGNE: It was based on the budget for the year ending 2002.

Q. - Thank you. What examinations and tests of the overall corporate expenses were undertaken to ensure that they were reasonable?

MS. MACFARLANE: Could you repeat the question, Mr. MacNutt?

Q. - What examinations and tests of the overall corporate expenses were undertaken to ensure that they were or are reasonable?

MS. MACFARLANE: In terms of an overall review or test I would say that there has not been a particular study. On elements of corporate expense there are ongoing reviews.

And let me give you three examples. In respect of our purchasing costs, there have been -- there has been significant moves made in the last three or four years to move away from the use of costly local purchase orders to use of a purchasing card which has led to the savings of four positions.

And that practice has been benchmarked against other utilities. In the telephony area, the telephony costs have been outsourced to a provider, again something that has led to reductions in that area. And that area has looked at their costs relative to other corporations.

In the information systems group, when the annual budgets are prepared they are compared to a Price Waterhouse survey of total IT costs per revenue base and total IT cost per employee. And they benchmark favorably against those stats for other utilities.

Those are some examples of -- and in our benefit costs, we look at our benefit costs relative as well. Our administration of benefits, we look at that relative to other organizations, and benchmark favorably.

So there has not been a comprehensive study. But each of the individual areas that are responsible for their costs tend to be looking for efficiencies and looking for measures against which they can tell whether they are pursuing those efficiencies well or not.

Q. - Thank you. Now I guess this is for any member of the panel. Perhaps we will just start with Ms. MacFarlane.

What are your thoughts on NB Power Transmission sharing corporate services with a generator company who will be competing with other generator companies to supply NB Power Transmission with energy-related services?

MS. MACFARLANE: If you are speaking to the issue of the fact that the corporate services group would have information about both generation and transmission that should not be made available to each other, that situation exists today.

And people who are in that situation sign a code of conduct today so that they do not release information one from the other. That goes all the way up to our board of directors.

And in situations where a head of the transmission unit or head of the generation unit need to make representation to our board about issues that the other ought not to do about, the other is asked to leave the room and not given access to the material or the minute.

In the positioning for the new entities to come into place we will be putting more rigor into those types of issues, particularly around information systems, ensuring that the security of information is such that it cannot be accessed one by the other, et cetera.

But we believe it is an issue that we can -- that we deal with well today and that we can deal with in the new format.

Q. - Now I guess this would be a question that relates to perception, but it may happen in the marketplace. How can other generator companies, distributors and the public be assured that a monology transmission company, namely NB Power Transmission, would be paying the appropriate amount for energy related ancillary services and would be treating all its customers equally?

MR. MARSHALL: Can you tell me which energy related services we are talking about?

Q. - No, let me rephrase the question. I have left a word out I guess. I will just strike that question and I will restart.

How can other generator companies, distributors and the public be assured that the monopoly transmission company, NB Power Transmission, would be pairing -- paying the appropriate amount for corporate related services and would be treating all its customers equally?

MS. MACFARLANE: I will deal with the first part of the question which is how can it assure it's paying the appropriate amount for corporate services. The -- in the Minister's statement it indicated that corporate services would be charged at cost. The allocation of those costs from -- let me back up a minute. Any opportunity where in fact that cost can be made direct by moving individuals or activities from corporate services into the entities that they form will be taken, where it is not possible for that to happen, there is work underway now to ensure that the allocation is based on a service usage and the billing determinants for that are being put in place as we speak. And the allocation methodology will be subject to audit.

And the allocation itself will be subject to audit.

These will be real bills sent out to these new entities and they -- those entities will pay it in cash so the entities themselves have a real interest in ensuring that they in fact are being charged an appropriate amount. Although as I say, that amount will be based on cost, not a market based transaction fee for service.

That's the first part of the question. I will ask Mr. Marshall to address the second part.

Q. - Thank you.

MR. MARSHALL: Yes. The administration of the tariff will be done in a non-discriminatory manner through the OASIS system. And the tariff on page -- actually it's in the standards of conduct of the tariff, in terms of administration. At page 332 of the evidence, A-3 lays out how the tariff would be administered.

Under the standards of conduct the transmission provider may not through its tariffs or otherwise give preference to sales for resale or for sales by the merchant function or by any affiliate over the interests of any other transmission customer in matters relating to the sale or purchase of transmission service.

Now the transmission services delivered through the OASIS system, the OASIS system is subject to FERC Order

889, code of conduct compliance requirements. It's auditable. And this Board has the authority to come and actually audit that system. There is a requirement to report continually through that system to the public and to all participants in the market, information that's available to the market and what goes on.

So I think that the standards that were there will provide for non-discriminatory treatment of all customers.

Q. - Thank you.

MR. MARSHALL: And I might add under the restructuring as it goes forward the tariff will in actual fact not be administered by NB Power Transmission. The tariff will be administered by the independent system operator --

Q. - Yes, you have explained --

MR. MARSHALL: -- who will then be treating everyone in a clearly arms length non-discriminatory manner.

Q. - Now what specific information will be provided to the Board concerning these transactions?

MR. MARSHALL: I think you are getting in to Panel D evidence here now. We are not the people to speak to it.

Q. - Well rather than calling Panel D back --

MR. MARSHALL: I can -- subject to check with Mr. Snowdon and Mr. --

Q. - -- would you make your best effort to answer, any member of the Panel before me now?

MR. MARSHALL: I will give you my understanding of the OASIS system and how it works. Mr. Porter could add some.

Q. - Well I think -- well perhaps you would just identify -- I believe you have done that several times over the last several days.

MR. MARSHALL: All of the -- all -- every transaction in the system, any booking, any reservation of the transmission system is publicly on the OASIS and available for scrutiny by all eligible customers in the market who can access that system.

MR. PORTER: To give some specific examples. Any reservations would identify a date at which the reservation was requested, who it was requested by, the point of receipt and the point of delivery, the quantity, start date and end date and the price at which the service was purchased. If it was a discount it would indicate that -- what the discount rate was. So a marketer could go on today and look at that information for all of the reservations that are on the OASIS system and understand and look and say well, am I being treated fairly here or not.

Q. - Yes, we understand that. The question was is what specific information will be provided to the Board? With respect to these services, is information going to be filed with the Board?

MR. PORTER: With which services should I understand?

Q. - Your corporate services.

MR. PORTER: Oh.

Q. - You are off on --

MR. MARSHALL: We are off the hook, okay.

Q. - We had a tendency to drift away and I had trouble getting in a word edgewise. We are talking about corporate services. And we would like to know what the -- you have identified them and how they are going to be divided and so on like this. How will the public know that the costs being charged are reasonable?

MS. MACFARLANE: In terms of the cost being charged, as I say, they will be billed and paid monthly. They will -- although in total the costs may not look significantly different than they do today, the portion that is called corporate and allocated, in all likelihood will be different. Because we will be taking whatever services we can out of corporate that actually can be turned into direct services and moving them into the area. The overall cost we don't anticipate changing but the differentiation between what is direct and what is corporate, we suspect will.

The charges will be based on an allocation formula not unlike what we have in the cost allocation study. In the case of something like the corporate accounting area, there would be a determination of what services are provided, what the portion of those services is to each of the areas or how they should share those and it will be billed on that basis.

In terms of what will be available to the Board, the -- we have talked already about the fact that internal management reports made monthly by each -- by the transmission business which will have in its OM&A costs an allocation of corporate will be made available to the Board. And --

Q. - On what frequency?

MS. MACFARLANE: I think we talked about monthly. On a monthly frequency those statements would be made available to the Board. And we can certainly ensure that on the OM&A table it is delineated in such a way that is clear what the proportion of corporate cost is. And then the PBR mechanism takes over from there, such that the next opportunity for the Board to look at them in detail would be the next time that the corporation is back for review at the tariff.

Q. - Will the allocation factors be a part of the monthly reporting?

MS. MACFARLANE: They certainly can be part of the monthly reporting. The corporate overhead allocation, as I say, right now it's about 12 -- it's 12 percent of the OM&A in the business unit. Pardon me, it's 12 percent of the corporate OM&A allocated to the transmission business unit. As we are moving closer to April 1, some of those costs will in fact become direct costs of the entity because they can perhaps more readily be provided by being directly in the entity. So they would show up in OM&A under labour, hired services, material, et cetera.

Q. - They would self supply?

MS. MACFARLANE: Pardon me?

Q. - They would self supply to themselves?

MS. MACFARLANE: That's right. And the corporate service portion then would be much smaller than the 12 percent. It would be a smaller number than that. So to include the pieces behind it in a management report, let me say it is not the area that the business unit should be spending most of their focus on in terms of cost reductions. But we certainly can make the information available to the Board any time they want it.

Q. - Thank you. Now at page -- in exhibit A-3 at page 77, NB Power Transmission proposes to charge customers a proportionate share of the total redispatch cost incurred whenever it is necessary to redispatch to maintain system reliability. Is that correct?

MR. MARSHALL: What line?

Q. - Pardon?

MR. PORTER: Okay. We have got it. That's correct.

Q. - Thank you. And exhibit A-6, NB Power BP supplemental 8 at page 8. NB Power --

CHAIRMAN: Just a minute, Mr. MacNutt, exhibit A-6?

Q. - A-6, Bayside Power supplemental 8, page 8. NB Power in its response committed to tracking revenues and costs associated with imbalance energy in a deferral account. Is that correct?

CHAIRMAN: I'm sorry, Mr. MacNutt, page 8?

Q. - BP supplemental 8, page 8, yes.

CHAIRMAN: We see, "Our response is, yes, please also refer to" -- Oh, I see. All right, go ahead.

MR. PORTER: Yes, we see that.

Q. - Now how will customers be assured that any costs and revenues for these services are properly accounted for?

MR. MARSHALL: Today we operate -- the energy control centre has always operated in dealing with external utilities in the past all transactions are actually auditable. And this account would be -- would be auditable.

Q. - Who would conduct the audit?

MR. PORTER: Mr. MacNutt, just while we are working on it. A point of clarification, unless I missed something what's -- we turned up two items. Like those are referring to two different services.

MR. MARSHALL: I would think it could be done by a third party audit.

Ms. MacFarlane just said I know that there are some transactions today done certainly with Maritime Electric that are audited by a third party accounting firm that would come in and do the audit.

Q. - Is this an area where an audit by the Board would be appropriate to review the costs incurred and revenues recovered?

MR. MARSHALL: Yes.

Q. - Ms. MacFarlane, looking at credit spreads. And with respect to the item credit spread, is it your position that the rates be charged -- excuse me, the rates to be charged should include a credit spread on existing debt of .91 percent?

MS. MACFARLANE: That's correct.

Q. - Is it also correct that the obligation with respect to existing debt, being the payment of the government guarantee fee, is only .6489 percent?

MS. MACFARLANE: That's correct.

Q. - Is it correct that the difference is to be retained at NB Power Transmission?

MS. MACFARLANE: That's correct.

Q. - Can you give me examples of other utilities which are permitted to recover more than the embedded cost of their existing debt?

MS. MACFARLANE: I don't -- I am not able to give you other examples. I'm not entirely sure that other utilities would find themselves in our same circumstances. The reason for wanting to collect the credit spread is back to this issue of ensuring that third party users of the transmission system, i.e., users who are not citizens or corporations of the Province of New Brunswick, pay full costs and do not get the benefit of lower provincial government borrowing rates which in effect are subsidized by taxpayers. That's the intent, is to ensure that there is a full cost imbedded in the tariff so that third parties pay that full cost.

Q. - Thank you. Now, Ms. MacFarlane, with respect to any significant changes to accounting policies, for example, depreciation, amortization rates, capitalized versus expense, what procedure does NB Power plan to follow concerning the involvement of the Board?

MS. MACFARLANE: To the extent that those procedures lead to significant changes, I would think that they would fall into the category of things that Dr. Morin referred to as Z factors. If the accounting procedures -- or the account changes, for example, are dictated by the CICA, Canadian Institute of Chartered Accountants imposing accounting standards that the corporation must follow, then that should lead to a Z factor change of this material.

If the depreciable life is changed because the plant -- the plant assets have been subject to damage from a storm, or thunder or technological change, again, those things are outside of management's control and should be represented as Z factors. And Z factors will be presented to the Board.

I have to say that we haven't given full reflection to any changes in accounting policy that are not dictated outside of management's control, but are in fact chosen to be made by management. But certainly to the extent that every time the tariff is reviewed, all of our accounting standards and policies are reviewed, they would come to the Board at that time.

Q. - Only at the time of a tariff review?

MS. MACFARLANE: That's the way PBR works. But, as I say, I believe we will be reporting regularly to the Board on interim periods. And they certainly would become aware of those changes because they would be disclosed in the financial statements. And we are happy to provide information as requested.

Q. - Thank you. Now, Ms. MacFarlane, what estimated cost, if any, is included in your expenses estimate for 2002, 2003 for the purposes of establishing a separate transmission company?

MS. MACFARLANE: Purposes of establishing a separate transmission?

Q. - Company, Transco?

MS. MACFARLANE: Company. In the test year, which is the year that we are establishing the entity, in the test year there is an additional 500,000 included in the OM&A cost for transmission. And that amount is related to opening of the market and establishing processes for monitoring the market, additional governance system changes, et cetera.

In 2002, 2003, there are no costs reflected in the -- there is no cost reflected in the corporate allocation for formation of the new unit. But included in the 2002, 2003 business unit cost there is 300,000 related to the same thing in 02/03.

Q. - You have just confirmed, and perhaps I didn't hear you correctly, that for 2002, 2003 you have no costs?

MS. MACFARLANE: There is no costs included in the corporate allocation. And that is because the corporate allocation of 12 percent of corporate OM&A to the transmission business was based on the 2002, 2003 budget.

The budget was developed before the restructuring announcement. So there is nothing in the budget to allocate. However in the business unit itself there were direct costs of 300,000 in 2002, 2003.

Q. - Have they been taken out for the test year?

MS. MACFARLANE: In the test year there is 500,000. And that is assumed to be an ongoing cost. The additional cost of having in place a Board, having in place a market that must be monitored and managed.

That is the only additional cost that we see of the new structure. That is the only cost that is reflected in there for the new structure.

Q. - Thank you.

CHAIRMAN: Mr. MacNutt, I'm going to interrupt you now. You do have a few more questions?

MR. MACNUTT: Very few.

CHAIRMAN: Pardon me?

MR. MACNUTT: I'm willing to gallop to the end.

CHAIRMAN: That is not good enough. No. Seriously, and I will tell you the reason why, is that the Board will have probably a half an hour of questions as well. And I know that Mr. Nettleton has a request to make of the Board concerning when we adjourn this afternoon.

And what I would like to do is have him and any of the other parties give an input to us before we break for lunch so that the Board would be able to discuss it.

Mr. Nettleton?

MR. NETTLETON: Thank you, Mr. Chairman, Commissioners.

The request, Mr. Chairman, really relates to the comments that you provided to us yesterday on your views of a potential adjournment arising if legislation is not tabled before the end of the evidentiary proceeding.

And this was certainly a potential outcome that you had recognized before the evidentiary proceeding had commenced. We think that it remains essential to ensure that all parties know the case that must be met and to ensure the Board has the best record before you to make an informed decision.

Last night my clients were certainly in the process of preparing our presentation materials for Mr. Hashey to ensure that he does in fact get an early Christmas present. And rest assured he will.

However, Mr. Chairman, we also spent considerable time thinking about your comments and indeed the likelihood of an adjournment in light of Mr. Hashey indicating that our panel would likely be excused mid week of the first week of the new year.

My clients have certainly invested a considerable amount of time and resources in this case. And they certainly believe that it is again in the best interests of all parties that costs not be spent unnecessarily and that the record in this proceeding be developed in as an efficient way as possible.

And so it really struck us, Mr. Chairman, that in light of the real likelihood of an adjournment and also the need to review the legislation and possibly to reexamine the evidence that has arisen to date, and the potential for reexamination to exist even for the JDI and CME witnesses that will be attending or possibly attending the first week of January, we thought of another alternative.

And that might -- that alternative might mitigate the additional costs and expenses and frankly the time of all parties. And that alternative would simply be to adjourn after today until such time as the legislation has been proclaimed, or at least tabled, Mr. Chairman.

What the suggestion really is based on, Mr. Chairman, is let's take the time now and await the outcome of the legislative process. We do not believe, sir, that this will put at risk the April 1, 2003 date any moreso than if we were to proceed as you suggested yesterday.

The point here is that there would be we believe some savings both to my client and others in respect of the time simply by reordering the steps ahead.

And also I think this process would ensure that the applicant's evidence and indeed their case is presented and tested first before that of the intervenors, which of course matters and makes sense, as it allows at least the possibility for intervenors, including my clients, to adjust and make changes, if necessary, to their positions.

So in summary, Mr. Chairman, JDI and the CME would like to request an adjournment at the end of today's proceeding. We want to ensure the record is complete.

We want -- and we do not want rather, to do so at the expense of additional time and resources. We would like to avoid that. And we are hoping that that does not in any way put at risk the April 1 date.

CHAIRMAN: I appreciate your comments, Mr. Nettleton. Help me out here. Because if in fact the legislation, when tabled in the House, is pretty much -- and when I say pretty much, NB Power has been relatively accurate in their prediction of what is in it, enough so that none of the parties nor the Board feels that we need to reconvene to discuss those small changes, then it will add time to the process. In other words if we proceed with JDI's evidence in that first week of January and we were to take a break and the legislation be tabled in that week or the following week, then we could reconvene in, I think it is the third week of January, for summation.

Otherwise we would be in a situation where if it were tabled let's say in that week after you are now scheduled to have your evidence, then we would have to come back the next week, if everybody were available, for your witnesses to give their testimony, take the week off after that. So we would add at least a week to the schedule, if not a couple.

Just help me out. That is the way I sort of see it from here, but --

MR. NETTLETON: I guess the thinking that we have certainly done is that the attendance of the JDI panel is not likely to take more than a two-day time frame.

CHAIRMAN: Yes.

MR. NETTLETON: And so it is quite clear we think that there is a high probability of an adjournment. Without knowing what the legislation says -- and we certainly have no knowledge of it. But without knowing what it says we can't presume that it will in fact not require reexamination of the witnesses of New Brunswick Power, the applicant.

For example should there not be an obligation to pay payment in lieu of taxes found in the legislation, I think that very much will impact the evidence that is on this record.

So the placeholder issue for us to ensure that that placeholder exists and exists prior to the evidence of the JDI panel proceeding, it strikes me as being most efficient to adjourn now to allow that placeholder to happen.

Because otherwise it really means that the JDI panel will come here, will present evidence on the assumption of legislation no one has seen, after the pause.

And if there is in fact a requirement to come back and retest the evidence, and indeed the evidence of all parties, I think we are going to be finding ourselves in a much longer and lengthier process than if we were simply to adjourn and wait and see what the legislation says.

CHAIRMAN: Okay. Thank you, Mr. Nettleton.

Mr. Hashey yesterday indicated that he would like to have a week from the close of the evidence to when summation occurred.

Do you have -- and Mr. Smellie, have any preferences that way yourselves?

MR. NETTLETON: We certainly appreciate Mr. Hashey's idea of there being at least some time between the completion of the evidentiary portion of this hearing and final argument.

I'm not sure that we would need a whole week. I think we will be doing our utmost to minimize the amount of time necessary to have that happen. Two days or three days should I think suffice for that exercise.

CHAIRMAN: Okay. And would you do the Board a favor over the lunch hour break? Attempt to make contact with your panel.

And if the Board were to agree with your presentation would your witness panel have any restrictions on when it is that they might be able to attend before the Board in the month of January?

MR. NETTLETON: Yes. I can certainly do that.

CHAIRMAN: All right. Now I will go around the other intervenors and then back to you, Mr. Hashey or Mr. Morrison, whomever.

Bayside Power is not here. And you have spoken, Mr. Nettleton, for the Canadian Manufacturers and

Exporters. The City of Summerside is not here.

Mr. Zed?

MR. ZED: Mr. Chair, I think you have alluded to my concern. I won't speak to the merit of the request. But the concern was more that we have a date certain that we would reconvene as opposed to just leaving it in limbo, because that presents problems for I think everybody's scheduling.

CHAIRMAN: Yes.

MR. ZED: I think I took your comment to Mr. Nettleton to be established -- to be looking at establishing another date.

CHAIRMAN: Shall we ask Mr. Knight to establish that?

MR. ZED: But I mean, I think you see the point I make is that --

CHAIRMAN: I do indeed.

MR. ZED: Yes.

CHAIRMAN: I mean, not only are the individuals in the room. But there is the room and then there are the translators and everyone else involved. Okay. Thank you.

Mr. Gillis is not here. Maine Public Service isn't here. Northern Maine Independent System Administrator is not here. Perth-Andover. Province of New Brunswick.

Mr. Knight, do you have any comments to make?

MR. KNIGHT: Yes. Just to reassure the Board and the participants here that staff are working diligently on both the market rules and the legislation and are trying to move that forward as quickly as possible.

In speaking with Mr. Nettleton this morning we had some sympathy for his position. However I think as you have stated, we have a concern that the hearing of the evidence and cross examination proceed, such that the Board has adequate time to make its decision in a considered and timely way.

I guess with your estimation of how the process might work, in accepting JDI's proposal, it would appear to delay things by one or two weeks. And we just feel that that might not be acceptable.

CHAIRMAN: Thank you, Mr. Knight. Saint John Energy?

MR. YOUNG: Mr. Chairman, we have no issue and no comment on this at all. It is not a concern of ours.

CHAIRMAN: All right. WPS is not represented.

Mr. MacNutt, my recollection of the amendments that occurred to our Act, the Public Utilities Act, would allow us to involve in a teleconferencing type of hearing?

MR. MACNUTT: Yes.

CHAIRMAN: That is certainly my recollection of what went through. We have come into the 21st century as far as --

MR. MACNUTT: Yes.

CHAIRMAN: -- the regulation is concerned. Okay.

MR. MACNUTT: Yes. That would be allowed, to my understanding, Mr. Chairman.

CHAIRMAN: Mr. Hashey?

MR. HASHEY: Thank you, Mr. Chairman. Mr. Nettleton did put this to me this morning. And I have had a chance to speak to my client. I guess the fear we have is the uncertainty of time.

We don't have any control when legislation is going to be filed obviously. If it was done now, and we anticipated it would have been, it would have made it easier for all of us. And I recognize that it hasn't been.

We don't believe that it is going to make any significant difference. Obviously I can't give any assurances to this Board. I have not seen anything in the legislation. That has not been part of my mandate nor have I ever been consulted on it.

But I did make some checks this morning. And I don't believe it is going to be terribly significant. But I can't obviously give any guarantees. It is under drafting as Mr. Knight still says.

CHAIRMAN: Yes.

MR. HASHEY: My worry, sincere worry, is timing and people's commitments on this. Obviously I will make myself available as best I can. I had anticipated --I have scheduled other matters, significantly scheduled other matters through February and March.

If I can get it out of the way in January there is nothing I can't change. But if it is into February and March I got some accounting to do to some courts in the province. This is personally. I don't know about other people.

I do agree with the suggestion that we should check on experts. I do know that I specifically had Dr. Morin prepared to return on the 6th and 7th. And schedules for these people I know is very, very difficult as well.

I would prefer to see it proceed as quickly as possibly. I obviously would prefer to see it proceed on schedule. But I respect the Board's thoughts on it.

But I'm deeply concerned of the uncertainty of the legislation and being linked to it as to where we really go with that. I guess really that is all I can say.

CHAIRMAN: Thank you, Mr. Hashey. Have you or Mr. Nettleton or any other counsel in this room been involved in a teleconferencing proceeding? They are not cheap, I can tell you that.

MR. HASHEY: No. We have just recently done one. And it is being done more and more on out-of-province discoveries.

They are really very expensive. And it is -- you know, I don't have any problem with it.

But it I think would be fairly complicated to set up. With two or three parties it is not a big deal, two parties principally. You know, you can focus on it. I have not had one of multiple parties, no.

CHAIRMAN: Mr. Nettleton, where do your witnesses come from?

MR. NETTLETON: I have one witness coming from Los Angeles, Dr. Earle, another witness coming from Toronto, Dr. Yatchu, and Mr. Mosher will be also attending on the panel.

But you know, I have been involved in hearings through teleconferencing. I quite frankly have found them not to be very effective.

The time in which -- the most effective one that I have been involved in is a proceeding such as this where a party could not attend the proceeding. And the party attended by way of conference call. And I quite frankly couldn't recommend it to any client.

CHAIRMAN: Now I'm not thinking of your examination in chief --

MR. NETTLETON: Yes.

CHAIRMAN: -- and cross. I'm thinking of when the legislation does come down, that is all.

MR. NETTLETON: Yes.

CHAIRMAN: Well, thank you for your comments.

MR. NETTLETON: Thank you.

CHAIRMAN: And we will take an hour for lunch and try and be back at 1:30.

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

CHAIRMAN: As a preliminary matter the Board wants to congratulate Mr. Porter on winning the pool. We discussed whether or not we could spin it out till after 5:00 but we decided it wasn't worth it.

MR. PORTER: The money will go to charity but it's still open for discussion on which charity.

CHAIRMAN: Mr. MacNutt.

Q. - Thank you, Mr. Chairman. Mr. Lavigne, please turn up exhibit A-4, SJE IRE-8, at page 480.

MR. LAVIGNE: Yes, I have it.

Q. - Now in the three line response at the end of it there is a reference to possible expenditures in the context of out and through transmission changes, is that not correct?

MR. LAVIGNE: Yes, that is correct. These are the amounts that Ms. MacFarlane was referring to this morning in her discussion, the 300,000 which is budgeted in the current fiscal year and the 500,000 which is budgeted in the next fiscal year.

Q. - And what will the 500,000 -- what will $300,000 cover and what will the $500,000 cover?

MR. LAVIGNE: These costs are primarily to cover the costs related to the opening of the market in terms of systems in the energy control centre. Also the market monitoring requirements that will have to take place. Those type of initiatives to ensure the market functions appropriately and properly.

Q. - What -- will these expenses be repeated in future years?

MR. LAVIGNE: There is an expectation that there will be an ongoing cost to these initiatives

Q. - Would you identify for us the amount that you expect to continue into future years and what the expenditure will be for?

MR. LAVIGNE: Yes. In order for the market to run efficiently, there will be a requirement for an advisory board. These costs will be reflective of that advisory board, as well as any consultative services associated with that in order to monitor the market. As well, there will be ongoing costs related to the systems in terms of maintenance agreements pertaining to certain computer systems. And costs associated with, you know, up -- keeping the system current.

Q. - Is that going to cost $500,000 each year?

MR. LAVIGNE: The expectation is that it will.

Q. - Now, Mr. Porter, I'm going to refer to the tariff document, which is exhibit A-3, and I want you to go to page 90. That's A-3, the tariff document, page 90, lines 28 to 29. This will be under the heading "Energy Imbalance associated with point-to-point service".

CHAIRMAN: We have got A-3, Mr. MacNutt.

Q. - A-3, the applied for tariff, the OATT, page 90, lines 28, 29. The heading on the page is energy imbalance associated with point-to-point service.

MR. PORTER: Yes, I have that.

MR. SOLLOWS: It starts at page 112. Okay. Yes.

CHAIRMAN: I'm finally there, Mr. MacNutt. Go ahead.

Q. - Lines 28 and 29 state, "In addition the transmission provider reserves the right to recover opportunities forgone because of energy imbalances."

Is it correct that opportunities foregone relate only to out of order dispatch?

MR. PORTER: Yes, that's correct.

Q. - Is it also correct that the treatment of out of order dispatch is described in the tariff?

MR. PORTER: Could you be more specific please in terms of the -- what you mean by the treatment of out of order dispatch?

Q. - The manner in which it is to be handled. The rules relating to it.

MR. PORTER: The treatment with respect to -- no, I guess I'm not -- I'm really not clear on what aspect -- I don't want to respond without knowing for certain what you mean by treatment.

Q. - I would like you to go to the section on out of order dispatch in the tariff.

CHAIRMAN: Where is out of order dispatch?

MR. MACNUTT: I'm asking the Panel to help us get there while we look as well.

MR. PORTER: There is a section on how the out of order dispatch will be calculated in that methodology. If that's what you are look for, that's in exhibit A-2, appendix B. I will find the page number.

Q. - No. We are aware of that provision. I wanted you to stay with the tariff. Now we have found the reference. I'm sorry we didn't have it earlier. Page 79, paragraph 34.4 re dispatch charge.

MR. PORTER: Yes. Yes, we have that. The question, please.

Q. - Yes. In light of that provision, would it be appropriate to delete lines 28 and 29 of page 90 so as to avoid any possible confusion? I'm sorry. Strike that. I will come to that.

I guess, really, is it correct that the treatment of out of order dispatch as described in the tariff at the page 79, paragraph 34.4.

MR. PORTER: The section to which you refer in the tariff, 34.4 is referring to redispatch charges associated with the requirement for redispatch in case of transmission congestion, which is different than the out of order dispatch cost that could be incurred under energy imbalance or under any of the ancillary services that are contained in the schedules of the tariff.

Q. - Would you explain the difference, please?

MR. PORTER: The redispatch charges referred to in section 34.4 of the tariff, that's page 79, are only incurred if there is a situation where the most economical dispatch of generation on the system is not possible because of a transmission constraint. That is the economic dispatch cannot be delivered to the load because of a situation where there is inadequate capacity somewhere in the system. For your information, on our system that's a very, very infrequent occurrence.

But it's in the pro forma because the standard is to have those obligations shared. The cost associated with that redispatch spread across all network customers on a prorata basis.

The out of order dispatch costs associated with ancillary services are determined when -- based on examining the costs of generation under a dispatch. The economic dispatch looks at the need for energy only, not for ancillary services.

When the plan is done for generation dispatch, that includes both the need for energy and ancillary services, if that cost is greater than the difference between the two costs, that is the plan without ancillary services taken out of account, and the plan with ancillary services taken into account, the difference between those two scenarios, those are the out of order dispatch costs that would be associated with the provision of ancillary services and those costs would be carried only by the customers that are taking ancillary services under the tariff.

Q. - Where is the out of order dispatch described in the tariff?

MR. MARSHALL: Page 76, section 33.2. This is the out of order dispatch related to transmission constraints that Mr. Porter referred to. But the procedure there is the same. In this case the -- I read from line 25 down. The transmission provider will initiate procedures pursuant to the network operating agreement to redispatch all network resources and the transmission providers own resources on a least cost basis without regard to the ownership of such resources. You are still trying to meet all of the requirements at lowest cost. But then whatever costs are incurred out of the order to overcome the constraint is then charged to all network customers. That's the redispatch charge based on section 34.4 that it refers to.

The methodology is the same. In incurring the redispatch charge for ancillaries, as Mr. Porter said, it's the cost of what would the dispatch be if you didn't need to provide the ancillaries, and what would the dispatch be now that you have to provide them. And if there is any additional cost, that's added on and charged only to customers taking ancillary services.

Q. - Thank you. In light of the fact that they are both described in paragraph 33.2 beginning at page 76 through 79, why cannot the lines I referred to you earlier, namely, "In addition, the transmission provider reserves the right to recover opportunities forgone because of energy imbalances be removed", from page 90 in exhibit A-3.

MR. PORTER: There may be some misunderstanding there. Mr. Marshall indicated that the calculation method is the same in both situations. But we are not talking about the same costs. There will be a distinction between those redispatch costs or you could use the term out of order dispatch costs associated with transmission congestion and a separate set of costs that would be associated with the provision of ancillary services. And in any particular hour there might be one, or both of those, or none. But there is not a --

MR. MARSHALL: And again, the opportunity costs referred to on the energy imbalance would be redispatch costs associated specifically with meeting that energy imbalance caused by that one customer causing the imbalance. Those costs would be charged back only to the customers causing the imbalance.

Q. - Where in the tariff is described the out of order calculations, the calculations of the costs?

MR. PORTER: Yes. It's not -- it's not described in the tariff. It's in the tariff design document but not -- it's not written out in the tariff itself.

Q. - How would a customer know that he is being charged properly for this service or for this charge?

P MR. PORTER: If that was a concern, it could be put into the tariff. Otherwise I expect it would be in the business practices that would be posted on the OASIS that would explain how these calculations are done. But it certainly

could be included within the tariff.

Q. - Yes, would you please include wording to be added to the tariff to cover it?

MR. PORTER: Certainly.

Q. - And undertake to do so.

MR. PORTER: Yes.

MR. MARSHALL: You may not get out by 5:00 yet.

MR. HASHEY: I take that as being one of the additions.

MR. MACNUTT: That's what I would request.

MR. HASHEY: Yes. I would request maybe that when the list is done it probably should be checked with the Board Staff and a comparison done to see if we are in agreement on what we are changing.

MR. PORTER: Yes.

MR. HASHEY: We will try to work towards that.

CHAIRMAN: Right. Thank you, Mr. Hashey.

MR. MACNUTT: That was my intention with the request for the undertaking, yes, Mr. Chairman.

Q. - Now, Mr. Marshall and Mr. Porter, with respect to generator costs for ancillary services, we have heard this morning and throughout the hearing, that your preferred method for pricing ancillary services is proxy unit cost, correct?

MR. PORTER: That's correct.

Q. - Now this morning you suggested that you have looked at the method of embedded costs but this is not appropriate because it would reveal confidential information on generation costs, correct.

MR. PORTER: Correct.

MR. MARSHALL: That's correct.

Q. - Now in JDI exhibit 26, schedule 4, page 4. And I'm referring to the page number at the bottom of the page as opposed to the upper right-hand corner where it says schedule 4, page 1 of 2. And it is exhibit 26, schedule 4 to that exhibit. And there is a numeral, page 4 at the bottom of the page.

It is a table entitled -- Bangor Hydroelectric Company Transmission Wheeling Rate, Reactive Supply and Voltage Control from Generation Sources -- Service.

MR. PORTER: Yes. We have that.

Q. - Now there are a number of columns. And I point you to column (c) which shows "Total production plant" and column (d) which shows "Generator original cost."

Is that correct? Those are shown there?

MR. MARSHALL: Yes.

Q. - In discussions with Mr. Nettleton on this particular table you indicated, and I think it was possibly Mr. Marshall, that Bangor Hydro has since divested itself of all of its generating assets. Nevertheless it would appear that prior to the divestiture, these generation costs were public knowledge because they are listed in this table. Presumably this was a requirement of FERC.

Would you confirm that for me or advise on it?

MR. MARSHALL: Well, whether it was a requirement or not, it is my understanding that these are the filing, the studies that they would have done in order to file their tariff with FERC. So this data would have been filed with FERC, yes.

Q. - Thank you. Is this still a requirement by FERC to make these costs public in today's market?

MR. MARSHALL: Not by Bangor Hydro or anyone in the New England power pool that we are aware of. There is bid-based markets for procurement of ancillary services there. And that is the direction FERC would want things to go to in the long-term, as long as there is efficiency in the market procurement of services.

If there is market power issues then FERC are looking at some type of regulation to cap the market and contain it, contain the market power.

Q. - Why was FERC requiring them to be disclosed by Bangor Hydro at the time of this document in 1995?

MR. MARSHALL: I'm not certain whether it was required or not. But it was at the time of Order 888 coming out. And all utilities in the United States under the jurisdiction of FERC were required to file tariffs.

Q. - That included public disclosure of those costs?

MR. MARSHALL: As I say, I'm not certain whether it was absolutely necessary on the generation side to file those or not. But it was necessary to file a tariff.

The transmission costs were certainly based on -- basically in the United States at that point in time FERC had access to all of the costs.

Because all regulated public utilities had filed information, accounting information with FERC under the standard code of accounts. So that the information was available to FERC.

Q. - What happens in those markets where the pricing of ancillary services is not bid-based? Is there still public disclosure of those costs?

MR. MARSHALL: I'm not sure what costs are actually disclosed. They are regulated rates that FERC would have to approve for provision of ancillary services in those markets.

Whether all of the detailed data behind the calculation of those rates is public or not, I'm not aware.

Q. - Thank you. Now Mr. Marshall, in going forward how will NB Power Transmission decide to build new transmission as opposed to recommending new generation?

And that it is in the context of the decision-making process to determine whether the transmission system should be upgraded versus siting a new generation at a particular location which would avoid upgrading the transmission.

MR. MARSHALL: Well, first of all, NB Power Transmission won't make decisions on the siting of generation. That will be made by free market participants in the marketplace.

The construction of new transmission would be based on the need to reliably supply customers in order to meet the reliable criteria needs of the system.

Q. - Now the second question, along the lines of transmission infrastructure, please explain why there are two parallel transmission lines, Coleson Cove to Marysville and Lepreau to Marysville?

MR. MARSHALL: Why there are two parallel lines? And just a correction. They don't go to Marysville. They go to Keswick terminal.

Q. - I stand corrected. Keswick.

MR. MARSHALL: I think the requirement for those two lines goes back to the fundamental design requirements of reliability of transmission system.

The system is designed to enable a continuous supply of load to all customers on the system without curtailment subject to the largest single contingency that could occur, that single contingency being either the loss of a generating unit or the loss of a circuit, a transmission circuit.

With the Point Lepreau station and the Coleson Cove station, 1600 megawatts located in the southern part of New Brunswick, in order to continue to reliably supply load across the whole province, you need to have more than one line running from those generators up to the Keswick terminal station.

In addition to that, I would think that there are also requirements from the Canadian Nuclear Safety Commission that put in requirements that there be a minimum number of circuits coming from a nuclear plant in order to assure its access connect to the system.

And they require at least two circuits at the same voltage. So I think those are the criteria that specify that there are two lines there.

Q. - In light of the fact that part of the cost of the two lines is generator-driven, should not that portion of the expenses of the two lines be attributed to generator and taken off transmission's cost?

MR. MARSHALL: Not -- the two lines are there to reliably operate the power system. They -- not only do they connect to Lepreau station, but it is not an isolated connection of Lepreau. It is a looped connection that is part of the looped mesh network, transmission network.

It allows power to flow through the whole system to supply customers. It allows power to get for instance from Bayside to the MEPCO interface in order for Bayside to export power to the United States.

It is a shared use of the whole system. Those lines from -- that connect the triangle from Coleson to Lepreau to Keswick are a base part of the bulk power system that are used by everybody.

Q. - Thank you. Now I guess it is my final question for the day. What specific provisions of the tariff address the issue of load factor improvements? That is open to anybody in the panel to answer.

MR. MARSHALL: Is that question load factor or power factor?

Q. - What specific provisions of the tariff address the issue of load factor improvements?

MR. MARSHALL: I guess the one factor in the tariff that would provide incentive for improved load factor would be the demand billing in on peak hours at 100 percent but the demand billing in off-peak hours at only 71 percent of the demand.

That provides an encouragement to use more energy in the off-peak hours which would then improve the overall load factor of the system.

MR. MACNUTT: No further questions, Mr. Chairman.

CHAIRMAN: Thank you, Mr. MacNutt.

BY MS. COWAN-MCGUIGAN:

Q. - Mr. Marshall, I understand from your evidence that New Brunswick provides ancillary services to northern Maine?

MR. MARSHALL: Yes.

Q. - And yesterday Mr. Dana Young of Saint John Energy asked the question as to --- he was looking at the cost of ancillary services. And your response I believe was that he can purchase his services at places other than the New Brunswick generators and you were saying anywhere in the Maritime electric area?

MR. MARSHALL: No, anywhere within the Maritime control area.

Q. - Control area.

MR. MARSHALL: Being New Brunswick, Nova Scotia, PEI or northern Maine.

Q. - Or northern Maine.

MR. MARSHALL: Yes.

Q. - Will northern Maine have the capacity to sell services to Saint John Energy?

MR. MARSHALL: No. Northern Maine today do not have enough capacity to meet their own requirements. And they purchase the additional resources they need under their products and services agreement from New Brunswick Power to the northern Maine utilities for a provision of those ancillary services if they are short.

Q. - I think you are somewhat confused. Because your answer was that he could purchase it from northern Maine if he wanted to. And yet they were purchasing the ancillary services --

MR. MARSHALL: If they were available. If a generator located in northern Maine and had a surplus, you could purchase from any generator that had the capability to deliver the services that was located anywhere in the Maritime area.

Q. - At the moment?

MR. MARSHALL: That's what I mean. And at the moment there are -- the only two entities today that would have surplus of those -- have potential for that would be New Brunswick Power and Nova Scotia Power. Northern Maine -- there are no entities that own transmission and generation in northern Maine. They are completely unbundled. WPS Energy Services which operates the tinker plant supplies a lot of the ancillary services to northern Maine.

Now in the free market place, WPS Energy Services could choose to sell those services to Saint John Energy. They don't have to continue to sell them into northern Maine. So there are sources that may be available in the market place that free parties would negotiate an arrangement. But currently there are no surplus of services inside northern Maine.

BY MR. RICHARDSON:

Q. - Thank you, Mr. Chairman. As I understand it NB Power has some legacy debt in US dollars. I assume in the breakout that Transco will assume their portion of that US dollar debt?

MS. MACFARLANE: That's the intention that we will take the cost of the whole pool of debt and ensure there is an allocation that puts it to each subsidiary proportionately.

Q. - What is NB Transco's position regarding future borrowings? What currency will it take place?

MS. MACFARLANE: Well if I and one of our board member's had anything to say about it it would be Canadian dollars. But it is the case as with the most recent issue that the

Province did that sometimes the US borrowings are more cost effective. It will be though the policy -- I believe the policy of the family of companies that any US debt will be hedged at the date of issue in Canadian dollars.

Q. - Is there any great advantage then if you hedge it fully at the time of issue in borrowing in US dollars?

MS. MACFARLANE: In this last issue there was the all in cost including the cross currency hedge gave us a borrowing rate of just around 5 percent Canadian.

Q. - My concern is that there is no US dollar stream of funds coming on transmission and therefore if you borrow in a foreign currency you are really basically playing the foreign exchange market --

MS. MACFARLANE: Yes.

Q. - -- and that can be devastating as the example of the MacDonald Bridge in Halifax/Dartmouth?

MS. MACFARLANE: Yes, that's right. And that's -- we clearly saw that when the CICA guidelines changed for NB Power as it currently exists. That's why our current policy -- and I assume it would translate into the new companies is that any US borrowing would be 100 percent hedged at the time of borrowing. And it would only be done if that net amount was -- provided an effective overall cost of debt.

Q. - What is the transmission company policy on intercompany accounts?

MS. MACFARLANE: Could you be a little more specific? In what respect?

Q. - Will borrowings be permitted between the butterflies?

MS. MACFARLANE: No. There will be services between the butterflies and they will be on a 30 day payment basis.

Q. - They will be settled. That's the key that I wanted.

MS. MACFARLANE: Yes. They will be settled, yes.

Q. - And the fact that there will not be any switching of funds between the two?

MS. MACFARLANE: That's right. It was felt that the investor community would not allow that.

Q. - You are exactly right.

MS. MACFARLANE: Yes.

Q. - Dividend policy. We talked about dividends about a week ago. When will you have a formal dividend policy that you can advise the Board that will be in place? Because you will have to have one prior to any bond issues.

MS. MACFARLANE: That's right. And I would assume that that will form part of the shareholder's agreement which will come after the legislation. Probably February we should have a dividend policy document.

Q. - As you see it now, we are working with deemed capital?

MS. MACFARLANE: Yes.

Q. - A lot of deem things. When in fact will these be funded? And again it's going to have to be prior to any bond issue --

MS. MACFARLANE: Yes.

Q. - -- because you can't go to the bank or with your balance sheet and talk --

MS. MACFARLANE: That's right.

Q. - -- say I got deemed capital here. You won't borrow much money?

MS. MACFARLANE: That's right. The intent is to have these transactions take place March 31st at midnight, so the debt equity swap would take place at that point in time. And prior to that all of the -- about the legislation, the regulations, the Board policy's, any agreements, et cetera would all be in place so that these companies can operate at that time.

A question that -- one question that has not yet been settled is when we will be going to a credit rating agencies, because obviously they will want to see all those things in place. They will want to know who the management teams are, who the Boards are --

Q. - That's right.

MS. MACFARLANE: -- et cetera. And it may be that we will have to ensure the companies have good working capital going into the first quarter so that they don't even need a credit rating for short term borrowings in that first quarter, so we can get everything settled then before the rating agencies.

Q. - When Dr. Morin was here he alluded at one point regarding the efficiency of the transmission company. You reconfirmed at that time that the transmission company was an efficiently run operation.

In Mr. Nettleton's cross examination there was a lot of discussion regarding benchmarks. And I understand there was no benchmarks in which you could compare this to.

How are you able to confirm -- or what system did you use to confirm Dr. Morin's comments to an efficient operation? What -- do you have your own system that you come up with this conclusion? And can you share that with us?

MS. MACFARLANE: Yes. To begin I think I was careful to use a different word than an efficient operation. I think I used the term that I believed it was well managed. And that was because I don't have specific firsthand knowledge. I -- that field is not my background and so I can't speak unequivocally to efficiencies in the area.

But as a consequence of Mr. Nettleton's discussions with us, we looked more carefully at the CEA study that Mr. Lavigne had indicated we had recently received. And NB Power does -- position is positioned, shall we say, in the middle of the pack of Canadian utilities on almost all fronts.

The issue is to ensure that that is meaningful to us and that we really understand where best practices are and how we can achieve those best practices. You need to get well behind the detail. It could be in some circumstances that our position among the comparable utilities is being affected by factors that are not related to efficiency or management. They are being related to either the nature of the other utilities or the nature of our utility. And we really feel we need to get behind those things more thoroughly than we have in order to be able move forward with achieving the efficiencies that will be driven really by the PBR mechanism.

Q. - Is it fair to say that the next time you appear before this Board regarding a transmission tariff, that we could expect to see some data that would give us the assurance that you are operating on an efficient basis?

MS. MACFARLANE: We are expecting that we will be required to do that, yes.

MR. RICHARDSON: Thank you very much.

BY MR. SOLLOWS:

Q. - Good afternoon. A few questions, and I think I would like to start by carrying on with the issue of depreciation and allocation of the long term debt.

MS. MACFARLANE: Yes.

Q. - If I understand it correctly the subject of a lot of discussion these last few days has been what number you record for the long term debt, whether it is the -- as of the audit date in the current records or the date at which the debt was issued. And if I understand it correctly you are -- your case is that you have -- you think it is more legitimate to take the actual amount of money that was realized at the date of issue and use that to determine the amount of long term debt that's going to be split between the butterflies? Is that --

MS. MACFARLANE: To take the issue date rate for translation of those foreign denominated US --

Q. - Got you.

MS. MACFARLANE: -- foreign dominated debt issues, yes.

Q. - And the argument being that it was at that time, that amount of money was then available for investment in the depreciating assets?

MS. MACFARLANE: Yes.

Q. - So I guess my question is when you split those depreciating assets up between the butterflies are you using gross book value of the assets, which is what would -- the way the division would actually have occurred or net book value which includes the depreciation?

MS. MACFARLANE: Yes. The -- effectively we are taking the net value of the assets, because that's all you can capitalize. When you create an entity you have an asset value and we are required to make these transfers at book value. Let's say the amount of assets -- at the March 31st 2003 when this happens, let's say it's 3 billion. And 3 billion gets transferred down to the various entities. That's a net book value number. And that's the asset base that you capitalize. So you from that point take a percent of debt and a percent of equity of that $3 billion and that becomes your capital structure. So effectively you are using the net book value not the gross book value.

Q. - Okay. In that case I guess my concern is that I haven't seen any evidence that the -- sort of the average life of assets between the butterflies is the same. And if the average life between the companies is the same then there is no problem doing it that way. But if the transmission company has a longer average life of assets, it will end up acquiring responsibility for more of the debt than perhaps it should.

So I'm wondering if you could simply -- to put my fears at rest --

MS. MACFARLANE: Yes.

Q. - -- could you break it down in terms of gross book value what the split would be? And if there is no significant difference then that's fine.

MS. MACFARLANE: Yes. I'm not 100 percent sure why it would be a concern. Because remember that as the assets are depreciating to get down to the net book value, at the same time the debt is being paid off. And so when I say that we are taking the debt translated at issue date rate, it's a lower amount of debt than was originally issued when the assets were financed because some of it has been paid off. It's just that that lower amount needs to be stated in currency terms that were there when it was borrowed, so to keep the two equal.

So I'm not sure that in fact your concern carries on simply because, as I say, both the asset depreciates and the debt gets paid down. But we are just keeping that translation rate constant over the period of the debt being paid down.

Q. - I guess my concern is that the -- if I just take the numbers and say 40 percent went to generation, 40 percent went to distribution and 20 percent went to transmission and crunched through the numbers after 10 years of depreciation if I assume there are differences in the lives, the average depreciation life I end up with a very different factor in the net book value. I get -- I might have 25 percent attributed to transmission as opposed to the 20 percent that was originally invested. So I'm just concerned that that percentage is -- are reasonably consistent with the --

MS. MACFARLANE: Yes.

Q. - -- gross book value percentages in terms of the allocation?

MS. MACFARLANE: Yes. But if I may, theoretically --

Q. - Okay.

MS. MACFARLANE: -- the cash flows from each of those entities is -- well the way Mr. Nettleton explained it is theoretically arising from the depreciation on those assets and that cash flow is what is being used to pay down that debt. So the depreciation that gets you from net book value to gross book value, though it is happening at different rates in each of the entities because they have different average service lives.

It is that cash flow that is drawing the debt down.

So the debt is being drawn down at different rates as well for each of the entities. Is that making sense?

Q. - Yes. I think I see where you are coming from.

MS. MACFARLANE: Okay.

Q. - Okay. That is fine. The next one that I would like to talk about briefly is following on from one of the Board's questions -- staff's question on load factor.

I went through the Stone and Webster study and found several references to the notion that if the company could improve its load factor they would have better operating statistics. Like operation and maintenance costs would be lower because they would be distributed over a larger volume of sales. Is that still going to be the case after the breakup of the company?

MR. MARSHALL: I don't specifically know. But I would think that if you can improve the load factor on a per kilowatt or per kilowatt hour basis, you would distribute costs, you know.

Q. - So there wouldn't be any direct increase in OM&A costs associated with the extra load that you would get by increasing the load factor. So there would be a reduction in OM&A costs per unit of load served?

MR. MARSHALL: Well, transmission is a demand business. If you can more load located on the resources that have some surplus capacity in them and not on the resources that need to be upgraded, then you would gain efficiencies clearly in the use of the system.

Q. - So that likely be the basis of their -- the conclusions? Yes.

MR. MARSHALL: I would think that that is what they -- but I'm not specifically aware of what they were talking about.

Q. - The transmission study and your annual report have data for the industrial and nonindustrial peak loads on peak and your sales respectively.

So in the annual report I can get the sales to each group. And in the transmission study I can find the peak load serving each group by service area, the five different service areas in the province.

When I did a rough calculation I found that the industrial class customers were coming up with about an 80 percent load factor. And your wholesale and direct customers were coming out around a 40 percent load factor. Is that more or less right?

MR. MARSHALL: The 80 percent is about right. 40 percent might be a little low.

Q. - Could I ask you to check that for me --

MR. MARSHALL: We could check that.

Q. - -- at some point? Not today.

MR. MARSHALL: The overall system load factor is around 57 percent.

Q. - Okay.

MR. MARSHALL: So the 80 percent is about right. And the rest of the customer loads have to be lower than 57 percent to average out. So it is somewhere down in the low 40's, but --

Q. - Okay. Well, you don't even have to check. If it is somewhere in the low 40's that would be fine. I guess what we have heard today is that your industrial customers have predominantly interval metering. And these other customers would predominantly not have interval metering.

And I'm wondering to what extent you think the existence of interval metering to serve these various loads would influence the load factor?

You might -- might going to interval metering for the low load factor customers not create an incentive for them to improve their load factor and your load factor?

MR. MARSHALL: They all have demand meters today. So the issue is of managing demand. The distribution companies that are at those supply points know that they peak in the on-peak hours.

So that is one of the issues with on and off-peak rates, to attempt to try to move some demand out of the on-peak into the off-peak hours.

That is the objective of the rates referenced in the White Paper that we -- Ms. MacFarlane said this morning we have targeted to be implemented next year by the distribution company.

Q. - Okay.

MR. MARSHALL: So that would -- it is the end use of energy by the customers in that area, if we can shift it from on-peak to off-peak, would improve the overall load factor of all of those delivery points in the system.

Q. - Right. And I guess the final sort of question that I have relating to this is in this -- the new tariff that we are talking about now versus the way it has been to this point in time, are the provisions that you have made for this kind of load shifting and load factor improvement any more -- any stronger than they were up to this point in time or are they about the same?

I mean, given that what we have had to date has given rise to 80 percent load factor for industrial and 40 percent load factor for the others, are we making changes under the current tariff that would address that problem and begin to encourage -- cause additional encouragement for the other customers to increase their load factor? Or is it sort of the same as before?

MR. MARSHALL: I think it will be about the same in the tariff. The on and the off-peak -- demand billing for on-peak and 71 percent for off-peak. There is quite a swing there. It is the high load factor loads that the industrials have where they may be able to shift load off and take advantage of that.

It is highly unlikely that any distribution loads would be able to take advantage of that, that they are -- unless they implement an on-peak, off-peak rate which will get customers to actually move loads off into the off-peak in order to reduce demand.

So I don't think it is a function of the transmission tariff per se. Although the 71 percent off peak is an incentive for those -- if there are some distribution supply points that may have a high load factor, there is an incentive to try to get them to move and take advantage of that.

OQ. - Okay. Moving on from that, questions about congestion and upgrades. And again looking through the transmission study I think I found a number of references. Go from memory, because I thought I had it here, but I have probably buried it in the -- no, there it is.

There were a number of references to -- let me see.

In the western region we see that there was limitation of the load growth on a few of the 69 kv lines, conversion of some to 138 volt kv will be required to prevent transmission line overloading.

Grand Lake there was need for transformer-related upgrades or some transmission. In the eastern region we read that during peak conditions the 138, 69 kv tie line in the Moncton area is unable to serve as a backup during contingency. And so there would be some work necessary there.

And in the southern region we see that historically you had transmission problems in the Saint John area in getting energy into the city, and that there were possibilities that, because of future generation, that the problems would reverse and there would be problems getting energy out of the city.

And so those all to me speak to constraint -- congestion-type problems that will have to be addressed through capital expenditures. And perhaps you already have begun to address them with the capital improvement program that you have already started.

But I guess my question is -- I couldn't find anywhere in the evidence any cost benefit or discounted cash flow studies that would form the basis of the decision of what upgrades to make and when to make them.

And I'm wondering do you have such studies that you could provide us?

MR. MARSHALL: I don't. Those studies would be done by the planning group in the transmission business unit, to look at the specific upgrades, look at losses, look at a lot of factors related to it. I think Mr. Lavigne may be able to speak in a little more detail.

Some of those -- some of that work I believe is ongoing. I know there is issues in around the Memramcook terminal upgrade which actually alleviates the Moncton issue that was there, and there is -- supply is another --

Q. - That was the impression I got.

MR. MARSHALL: So there is work ongoing in order to upgrade the system and address some of those areas. I think Mr. Lavigne could say more.

MR. LAVIGNE: Yes. That particular study ties in with the Stone and Webster study. And our capital program does take into consideration many of these issues.

Mr. Marshall mentioned one of the -- the major programs that we actually are beginning in this fiscal year which is the upgrade of the Memramcook terminal. There is also a major transmission line that we are in the process of developing to strengthen or reinforce that particular part of the province.

The Saint John area, we have done a lot of work in that particular area, stemming from both the transmission planning study and the Stone and Webster, as well as up in the Tracadie area where we have just energized a major terminal and line to deal with some of the issues that we have up in that area.

So there is a definite tie in there to those studies in terms of what is in our capital plan. It is a multi-year plan spanning, you know, upwards five to -- yes, three to five to seven years, so --

Q. - Yes. I guess my question is do you have any discounted cash flow analyses or cost benefit studies to justify the decisions and the expenditures?

MR. LAVIGNE: A lot of these expenditures are dealing with reliability. I do know that they look at these. I'm not sure if they do a discounted cash flow analysis on these.

But they do look at different parameters when looking at upgrading the infrastructure in these various areas.

Q. - So is there a report written or something that could be filed with the Board that indicates the criteria for the decision?

MR. LAVIGNE: I'm -- yes, I'm not sure what would be available. But I certainly could --

Q. - Okay. We will just leave this between Board staff and you to sort out what we can see to deal with it.

MR. MARSHALL: I would like to make a comment. You mentioned about -- that there may be -- it appears that there may be congestion from a lot of these areas. That is very specific. Most of those are related to supply to load in certain areas.

That is not the nature of the congestion that we are concerned about on the system, where there is congestion that you can't get generation out or into different areas so that you can dispatch all of the generation in an economical manner.

Q. - Like the area around Saint John.

MR. MARSHALL: The only one there mentioned is the Saint John one. With regard to that, the report -- the Stone and Webster report was written in '99, and the work done I think prior to that.

The second 138 kv line from Norton running back into Courtenay Bay has been completed since then and is operational. There is a second supply into Irving Refinery. So the Saint John area supply has actually been reinforced since the writing of that report.

And now we -- you know, there are some issues. But Bayside runs in the wintertime. And with that unit running we don't have a congestion area concern in that area.

Q. - Okay. That is fine. As long as we can sort out what the documentation is, we will carry on with that. I guess from there I want to talk briefly about the lines at issue, the twin lines. I think under your numbers they are lines 3002, 3003 and 3009. And they form that triangle between --

MR. MARSHALL: Keswick, Lepreau and Coleson.

Q. - -- Keswick, Lepreau and Coleson Cove. And I guess what I am looking for there is some level of comfort that those meet a reasonable test for used and useful for the network as opposed to the generators. And what I am wondering if you could provide, and it wouldn't have to be right away, would be your network modelling that shows the loads on those lines at peak and at peak with Lepreau removed, and perhaps at peak with another contingency removed or second contingency removed? And also provide us the total load -- or capacity of those lines just so that we can see how much of those lines -- those resources are really tied to generation contingencies or other supply load contingencies?

MR. MARSHALL: We could run a few load flows under different conditions to illustrate that those lines are used.

Q. - That you thought would be appropriate.

MR. MARSHALL: The issue there, you have to understand, is that the system has been designed to be able to move significant power from the south to the north and significant power coming in from Hydro Quebec from the north to the south and still have power to be able to go on the MEPCO tie through Nova Scotia and bring power in from interconnections and move it around the province in order to continue to supply all load under any contingencies that occur, which would be loss of the whole Coleson Cove plant or loss of the Hydro Quebec and others. So we could run a couple of load flows to show you under this situation the power flows in this direction. Other situations it flows in a different direction, but the lines are used.

Q. - And it's used and useful.

MR. MARSHALL: And the other point -- the key point and the reason for the two lines is that they form a triangle essentially between Keswick, which is the Mactaquac station, Point Lepreau and Coleson Cove. In the springtime, it's quite possible to have all three of those plants running. Mactaquac at 600 megawatts, Lepreau at 600 and Coleson at 6' or 700 megawatts. If you lost a line in between them, you have to still continue to be able to run those units without having to trip them off or move them back. So there is that aspect of the reliability of those lines as well.

Q. - Well you could pick the conditions that you think are appropriate?

MR. MARSHALL: Yes.

Q. - Finally, just two last areas. Reliability is an issue, of course, in the design and operation of the transmission grid. And I guess when I read -- what reading I have done on the topic, there is issue -- the terms loss of load probability or expected energy not served, those sorts of quantitative measures of reliability come up. And I am wondering do you have any such quantitative studies and targets for reliability that you will be using in terms of your decision criteria for capital additions and investments?

MR. MARSHALL: Transmission system reliability does not work based on loss of load probability or for those types of analysis. Those essentially are generation supply criteria that are used for generation energy supply.

The methodology that NB Power subscribes to as part of the NPCC planning process is the single contingency analysis. And it requires study of the system under all of these contingencies. So which is the worst contingency in particular areas, which ones affect the bulk power system, which ones affect other areas. And so there are many, many load flow studies that are done. Many, many system stability studies that are done to trigger if this line trips, then how does the system survive. The intent being that the system can survive the loss of any one of those contingencies and continue to stably operate reliably and move to a new stable, steady state condition. That's the criteria that's done.

We report to the Northeast Power Coordinating Council every three years. There is study done to upgrade and show our effect on the overall bulk power system within the region.

So if you are interested in that, we could undertake to get the most recent study that was done and give it to you, so you could see the studies that are done to do that.

Q. - Background material might be helpful. That would be fine. And the final thing is -- relates to generation-based ancillary services. And I know in the slide presentation you had four alternatives that were considered before you settled on proxy unit costs. And I guess I go back to every -- or certainly my first experience with economics 1,000 being -- not being terribly memorable, but I remember two things. Supply and demand and opportunity costs. And I guess the thing that sort of struck me is that it doesn't appear that you gave much consideration to the generation company's opportunity costs in having to supply these services over being able to sell them into the New England market. And I am wondering why that's the case?

MR. MARSHALL: Well, first of all, as I said to Ms. Cowan-McGuigan, it's not possible to sell ancillary services outside the control area.

Q. - Generation-based ones like --

MR. MARSHALL: Even the generation-based services. Now the only issue where you may run into -- that you may be able to sell is that this is capacity. This is generation capacity.

It is possible to sell generation capacity into another control area as firm capacity to meet their requirements. And then if it would be dispatched, it can be used then to generate energy and sell into that market.

So in that sense there may be some competition to say that NB Power Generation may be better off selling this capacity into the other market and not supplying the ancillary services in New Brunswick.

We have taken the position that NB Power Generation has had the obligation to supply all the ancillary services in the system today. And that what we have proposed is a proxy pricing method, which we think gives them the reasonable return, a reasonable value on that in order to fulfil the obligation so that all customers in the system as this market goes forward can continue to get products and services under prices, terms and conditions similar to what they have had in the past.

So the fact that NB Power Generation sells into the export market, they sell there today after they have met their obligations to meet New Brunswickers' load first. And they still have that same obligation on them in the go forward world.

Q. - The other thing that's in my mind as we discussed these things, there is a lot of discussion about the price, but not a lot of discussion about the quantity. And I guess how is the quantity of the product that you are going to buy from NB Genco determined? I assume because of the concerns you have already expressed about public availability of cost information, you wouldn't want to let -- make those numbers public, but in that case then how do we -- how can we be confident that, for example, Transco is buying more of these services than they would otherwise require to run the system and keep it stable and reliable?

MR. MARSHALL: Actually the quantities are in the evidence. And Mr. Porter I think can lead you to it. It's in appendix B of exhibit A-2, in the transmission tariff design document. So the appendices of that document that calculate the rates, the actual quantities, it's on page 71. And the quantities of capacity required for each of the services are in column 2 of that table.

Q. - Okay.

MR. MARSHALL: Now I might just add that those capacities are not capacities that NB Power Generation says here is how much we will give to you in order to meet your needs. These quantities are determined by the transmission operator and essentially are -- the first one is on regulation and load following relate to the nature of the load. How much do you need in order to follow? So however variable the load is determines how much you need.

The other quantities for spinning reserve, supplemental and 10 minute and supplemental 30 minute reserve are factors that are dictated essentially by the rules of the Northeast Power Coordinating Council. That you -- the 10 minute reserve is the amount you have to have to meet the first contingency on the system. So if Point Lepreau trips, you need enough for that. And you then -- that's within the control area. Now there is some reserve sharing arrangements with Nova Scotia and PEI and the others. And there is another table in those appendices on page 69, which shows how the control area -- total control area requirement under column 1, the Maritime Control Area, that's the requirement for those resources. And then it shows you the reserve sharing from Nova Scotia and then how the remainder is allocated between PEI, northern Maine and New Brunswick, to say you have to carry your share. That gets us to the quantities that we need.

So they are really driven by the reliability criteria in order to run the system in a reliable manner.

Q. - That's fine. Then I think the last two things relating to this -- or one thing I think will deal with it. In terms again the cost of generation-based ancillary services, and I think you mentioned it earlier in response to another question, the little thought exercise of the dispatch of two units, one with different marginal costs giving rise to some benefit that could go to capital cost. I think I heard somewhere in the proceedings that most of these generation-based ancillary services will be provided by a combination of energy from Coleson Cove and capacity from Mactaquac in terms of spinning reserve, is that fair?

MR. MARSHALL: No. First of all, there is no energy associated with these ancillary services, other than the out-of-order dispatch costs.

If the system is running reliably, the ancillary services are in sense the insurance policy behind the system that if a unit trips, you then have capacity in place to accommodate the trip. If the load changes, you have capacity under control, which will automatically adjust to balance the system load against the system generation.

So it's really capacity is what the issue is. And that capacity is predominately provided from Coleson Cove and Mactaquac and a little bit from Beechwood. But in the time period when the hydro system is energy-limited, there may be two units running at Mactaquac, well you would have -- you may run three units and have them a lower load level, so that would meet the spinning reserve requirement.

Q. - Yes.

MR. MARSHALL: And then you have other units you could start in a hurry, so -- depending upon what you can do. So it's supplied there. If Coleson is running, instead of running one unit at 300 megawatts, you would run two units at 150 and you have -- based on the ramp rate of the units, you can increase 50 megawatts in 10 minutes, so you can count

50 megawatts off each unit towards the 10 minute reserve that's spinning.

Q. - And I guess where I was coming from in terms of energy is if you had to use some of your -- eat into hydro energy that you would have, you presumably have to make it up out of --

MR. MARSHALL: That's an issue with the out-of-order dispatch costs is the value of hydro energy. The actual energy itself has no costs in terms of the energy source. But the value of it is what energy does it displace on the system. And so if you have to use more of it in the middle of the night in order to do load following and automatic generation control while something else changes, the value of that energy really is what was it worth the next day on peak, because you have used it up at the wrong time. So that's part of the out-of-order dispatch costs that has to be considered in the calculations.

Q. - Yes. I guess you are getting to I guess the point that's bothering me is if you are using it in the middle of the night, couldn't you equally argue that you are going to make up that energy out of something like Coleson Cove and therefore price your generation-based on ancillary services based on number 6 fuel oil in Coleson Cove? In the knowledge that very soon you are going to be running a fuel in Coleson Cove that we know is cheaper than number 6 fuel oil and so therefore we have left you a margin for capital as well?

MR. MARSHALL: You could do that. I mean, that's part of the out-of-order dispatch costs of the hydro that we would put a value on it in terms of what the cost is the next day.

So today that would be the situation. We would value it at Coleson. The generation marketing group may in actual fact value it at more than Coleson. They may say no that's energy we could have sold into the US market at a certain price and now we don't have it because it's not here. So there is an issue in terms of what --

Q. - Which brings us to opportunity costs.

MR. MARSHALL: -- that is, is an opportunity cost. But the intent here is not to include that type of opportunity cost in the out-of-order dispatch. It's what are the cost differentials of actual dispatch.

Q. - That's fine. Thanks very much. Just as Chair of the Board I am always terribly apprehensive of anything being filed in a confidential fashion. And Mr. Hashey I'm sure shares that. We have been through that a number of times as to the fact that the law says that if we were to base our decision on something filed in confidence, that was not available to all of the parties, why the courts would overturn the decision. So I'm loath to do that.

But just following up on what Commissioner Sollows has said, Mr. Marshall, you keep quoting, and Mr. Porter for that matter too, the generation believing the information of the actual cost of providing ancillary services to be confidential because of the open market coming.

Coleson Cove will be going to Orimulson. And that will occur what, in the next two or three years?

MR. MARSHALL: If it's on schedule it will be November of 2004, yes.

Q. - So any costs dealing with that generating unit today that would become public will provide no benefit to competitors after it goes to Orimulson will it?

MR. MARSHALL: That would be correct. But it would provide benefit to competitors today until it goes to Orimulson.

Q. - Have any of the wholesale customers of NB Power indicated that they want to seek electricity elsewhere?

MR. MARSHALL: The issue is not whether customers may or may not leave the system starting next April 1st when the market opens. Our generation peoples' concern is that they already compete in a competitive market today across the whole northeast region. And release of their cost information would disadvantage them relative to Nova

Scotia Power selling into the market. Selling on a bid price into PEI, against what Maritime Electric may want. Selling against WPS Energy Services into Northern Maine. So there already is competition going on in this market place today. So release of that information would disadvantage them today.

Q. - Now back to -- I have difficulty with that myself. But your counsel will definitely try and convince me otherwise during summation

But I do in that there is no large industrials that have given you the one year notice under their contracts to this point in time is there?

MR. MARSHALL: That's correct. We have -- nobody has given notice that they are going to the market.

Q. - So the competition is outside of the borders of this Province, and therefore outside of the jurisdiction of this Board. However, let's just look again at JDI 26. And Mr. MacNutt was questioning you on that and he went to a certain extent. But when FERC 888 came into force and they required the open access tariffs to be filed for wholesale customers across the States, presumably, and this is a presumption on my part, most if not all of those utilities were regulated by State regulators as well as Federal regulators, and in a monopoly situation. And the information concerning those utilities would be public information at that time.

Now my question of NB Power is that I would like you, over the next couple of weeks, to find out if at the time of FERC 888 in order for a utility to be compliant with that tariff filing requirement, if they in fact had to file this information in a public way with FERC? Because if they did, then when those markets opened up in the US the information that we see on this exhibit would have been public and known to all?

MR. MARSHALL: Yes.

Q. - Okay. So I would be curious in knowing that, as to whether that was public knowledge at that time. I mean, Mr. Marshall, as you have said here, you have a very good idea of what it costs for most of those generators in the State of Maine to produce a kilowatt hour. And don't tell me you don't, because you do. I mean you evidenced --

MR. MARSHALL: I know what -- I know what the price of gas is, because that's public. You can find that out.

Q. - Just following up on that, when Northern Maine entered into agreement with you to purchase ancillary services from NB Power, that was not regulator approved, was it?

MR. MARSHALL: No. Oh, it was approved by the -- it was approved by the Maine Public Utilities Commission --

Q. - Did they have the kind of information that I'm talking about filed with them when that was approved?

MR. MARSHALL: No.

Q. - I see. Where else could Northern Maine have purchased ancillary services other than from NB Power?

MR. MARSHALL: Nova Scotia. I guess they -- this was one of the issues --

Q. - You sort of -- you had some market power didn't you?

MR. MARSHALL: Yes, we did. One of the issues with that agreement in Northern Maine was this concern of market power. Our system was open from transmission was available, but there certainly were parties that had concern of NB Power exerting market power over Northern Maine. And so that's why we contractually entered that agreement, to alleviate any concerns of how that would work. So it was -- there were contractual obligations in order to fulfil it, but they could lean on that and that would mitigate the market. So that was an issue at the time.

Q. - All right. Was that agreement filed with the Maine regulator?

MR. MARSHALL: I believe it was, yes.

Q. - So would it be public knowledge?

MR. MARSHALL: Except I think the schedules, as Mr. Belcher was here, he filed the -- had the agreement. I think the agreement is in the record here, but not the schedules that have the actual pricing on the services in it. And so that --

Q. - But my question is when it was filed with the Maine regulator was that public knowledge? Not meaning what he filed here.

MR. MARSHALL: I don't think those schedules were.

Q. - Would you find out for me on that?

MR. MARSHALL: Okay. We will check on that.

Q. - And if in fact it is a public document in Maine, would you undertake to file the whole document here?

MR. MARSHALL: We will do that, yes.

Q. - Thank you. Just one comment on NB Holding giving managerial direction or advice or talents to the butterflies. I wish you luck. Because being the Chair of a Board and realizing what apprehension of bias means, why you will have a -- it will be extremely difficult for you to deliver those services to all four butterflies and not have some who will be apprehensive that there will be information shared. I will just say that.

And, Ms. MacFarlane, you talk about significant changes caused by a CICA standard. Is that GAP that you are talking about?

MS. MACFARLANE: Yes, it is.

Q. - Yes. Refresh my memory, because it was the early 90s the last time I was exposed to GAP. But at the time there was a provision that if a utility regulator required that it report things in a certain fashion, then that was acceptable for GAP?

MS MACFARLANE: That's changing.

Q. - Is it?

MS. MACFARLANE: Yes.

Q. - All right, tell me how?

MS. MACFARLANE: There is a new exposure draft out on the definition of generally accepted accounting principles. And under that exposure draft it would indicate that practices that, for example, utilities followed in the past either following principles laid out for them by the regulator or perhaps by their owner. And using those as opposed to GAP will no longer be allowed in the future.

Now that has caused some controversy. And so that exposure draft is somewhat on hold until there is a study being released on regulatory accounting by the CICA. And until that is released the exposure draft is on hold. But it at this point in time the thinking of the CICA as we understand it is that an entity can keep a set of books, so to speak for rate making. But those do not necessarily have to be same that they issue to investors or the public generally. But there should be comparability of principles across entities for information released for public consumption.

Q. - So effectively you are going to have three sets of books.

MS. MACFARLANE: At least two.

Q. - One for the regulator? One for your investor? And the third one for income taxes? That's not a catch question.

MS. MACFARLANE: We are -- yes, that's right.

Q. - All right. The other utility that we regulate does pay income tax. Those are all my questions. Mr. Hashey, any redirect?

MR. HASHEY: Yes. Mr. Chairman, I have two questions in redirect only. We shouldn't take very long. And then I would like to complete a number of undertakings, which is probably no more than a 10 minute job. So if we could just continue?

CHAIRMAN: Yes.

<u>REDIRECT BY MR. HASHEY</u>:

Q. - Thank you. The first question I direct to Mr. Porter. During your cross examination by my friend Mr. Nettleton, there appeared to me to be some confusion in relation to the generator capacity charges and the rates for ancillary services. I know there are exhibits and interrogatories on that. Can you just clarify for us how they are related?

MR. PORTER: Yes, I can. I would like to refer to the document we just looked at a minute ago which is in exhibit A-2, appendix B, page 71.

There has been a bit further discussion on this topic today and the key point being that there are the two sets of, for the purpose of discussion I will call rates, one is the rate at which revenue flows from the transmission provider to the generator for the provision of the capacity based ancillary service, and the other rate being the rate that is charged to the transmission customer based on their usage of the transmission system.

The former on this table is in column 1, the latter, that is the rate charged to transmission customers, is in column 5. And the dollar figures in column 1 again reflect the dollars that flow from the transmission provider to the generator, and those are also the figures that are included on exhibit A-23. I don't think there is any need to turn that up, but we had a significant amount of discussion about that yesterday, and I just wanted to make that connection between this document and exhibit A-23.

And the calculation to get from there to the rate that is charged to the transmission customer is to go to the second column, which Mr. Marshall spoke about a few minutes ago in terms of the quantity of the service required, and he spoke about how it's driven by reliability criteria that are defined by external parties.And so the quantity in that column can vary significantly from one transmission system to another transmission system, and largely driven in the case of the reserves by the size of this first and second largest contingencies on the system.

So simply the first column is the dollar rate -- dollar per kilowatt year of generation. That number is multiplied by the figure in the second column. I will take the specific example of the -- let's go to the bottom row, the 30 minute supplemental reserve with the $56.61 per kilowatt year is multiplied by the requirement for 157.9 megawatts, which leads to an annual revenue requirement of 8.9 million in column 3.

And the next step would be to determine the rate which is charged to the transmission customer, take the total revenue requirement of 8.9 million, divided by the total billing determinant which is the load data or transmission customer usage data of 2,571, thereby getting the annual rate for that ancillary service in column 5.

So the key point being here that there are three very important numbers that drive what the rate will be that is charged to transmission customers for this service, the first one being in column 1, the revenue requirement at the generator, the primary supplier of the service, two is in column 2, the service, the quantity of the service that is required to be purchased from the generator, and then thirdly in column 4 the usage or the magnitude of the load or transmission customer usage of this service.

And I think -- so as I said earlier these numbers can vary -- the latter two numbers can vary quite a bit from system to system, the quantity required and the amount of load usage in the system. We have seen on A-23 that our numbers are comparable to those of other systems, but if we looked into it I think we would see differences in the quantity required and in the usage of the transmission system.

And just lastly that in column 5 where we have the rates that are charged to the transmission customers, those are defined and compared with the rates of others in the response to Saint John Energy's interrogatory number 3.

That's my explanation.

Q. - Thank you. Question directed to Mr. Marshall concerning the predictability of the proxy method of ancillaries. Under Mr. Nettleton's cross-examination it was indicated the variability of dispatch costs and price discounts reduce the predictability of the proxy-based rates. And the question, Mr. Marshall, would these factors influence the predictability of rates determined by other methods.

MR. NETTLETON: I'm sorry, Mr. Chairman. I must object. This is not proper for redirect. This is not another opportunity for the witnesses to put on the record their positions with respect to evidence and the cross-examination that has occurred.

Redirect is intended to clarify any outstanding issues that arise and they are not questions that arise by way of leading questions. So I must object.

CHAIRMAN: You are going to have to start to pose the question again, Mr. Hashey.

MR. HASHEY: I haven't posed the question yet.

CHAIRMAN: Oh, okay.

Q. - The question, Mr. Marshall, is would these factors influence the predictability of rates determined by other methods.

CHAIRMAN: Hold on a second. There is a preface to that that -- you were saying something else that I wasn't following that closely.

MR. HASHEY: Yes. I'm talking about the proxy method obviously for ancillaries and --

CHAIRMAN: Was there something as Mr. Nettleton has said that was -- might be confusing as a result of the cross-examination that you want to clear up? And by that I'm not saying that you can go through the explanation again, but is there some part of it? Redirect is, as Mr. Nettleton said, to clear up any impression that is improper that has been left as a result of cross-examination.

MR. HASHEY: Well I think all I was saying, Mr. Chairman, was that we felt that there was an indication arising from the cross that the variability of the dispatch costs of the price discounts would reduce the predictability of the proxy-based rates, and I just wanted to comment on that.

MR. NETTLETON: Well, Mr. Chairman, he can save that for argument if he thinks that there is something incorrect with the evidence that is on the record with respect to that topic. But it's not appropriate for Mr. Hashey to have his witness be given the opportunity for, you know, saving face with what is on the face of the record.

MR. HASHEY: Well I will drop it.

CHAIRMAN: Thank you, Mr. Hashey.

MR. HASHEY: If that's the feeling, I don't want to offend any rules here.

CHAIRMAN: Thank you, sir.

MR. HASHEY: Okay. Can I jump into undertakings?

CHAIRMAN: Please do.

MR. HASHEY: Okay. I'm going down the list of undertakings, Mr. Chairman, hoping that I clear up many, and I was going to wish you all a Merry Christmas, but I think you have cut out somebody's Christmas here by the number of ones asked for today that we haven't really addressed yet, but we will get to those. But trying to clear up as many as we can. I think there was only one left from A and D as I can recount and we kept -- obviously Ms. Tracy keeps an awfully careful list here with assistance.

There was one that says examine the tariff to see if there could be clarification between inadvertent energy and energy imbalance. What we suggest is that we add that to the list and provide definitions in relation to the amendments to the tariff that we were going to do that would seem to fit in that.

So If I can jump from that I would go -- I have got numbers here if you can bear with me. The next one is the issue on the updated business plan. I have not been able to get authority to release any updated business plan at this point in time. Now that's not saying that that won't be provided, but we need a little more time to address that. We haven't had much time to address anything as you can understand since we have been here throughout.

The next one is the one that immediately follows that which relates to an update I believe of exhibit RAM-4, referring to Morin, and we do have a document to table in that regard today. So if we could have that one.

CHAIRMAN: This will be A-32.

MR. HASHEY: I think that was one that was requested by Dr. Sollows.

CHAIRMAN: Yes.

MR. HASHEY: And I could relate it to page 1,299 of the -- in reference to the transcript if that would assist anyone.

CHAIRMAN: Go ahead.

MR. HASHEY: The next one?

CHAIRMAN: Yes.

MR. HASHEY: The next one immediately following from pages 1,373, Mr. Nettleton I believe asked a question to provide volume levels -- what the volume levels would be once the Coleson Cove project was completed. And we have a document to distribute on that.

CHAIRMAN: That will be A-33.

MR. HASHEY: Then, Mr. Chairman, unfortunately there were two that followed that at pages 1,411 and 1,422 of the transcript that Ms. Willett was working diligently on dealing with foreign exchange rates, sinking funds, hedging. Maturity dates of US debt, this type of thing. Unfortunately, Ms. Willett is the latest victim of illness and we don't have those. So we will have to undertake to provide that to you.

And I think there is a couple more only. Keep the list going here. The next one is a question that was directed to Ms. MacFarlane, I believe, concerning -- at page 1,453 and I think the request was from Mr. Nettleton that -- you know, concerning we have translated the debt at issue rate as opposed to a statement date rate, which is -- which you will see in note 10. What is the difference in the two calculations by in large? And there was a request to determine the difference between the two calculations. I think we have a document on that. I think Ms. MacFarlane can address that once we table that as well if we could.

CHAIRMAN: A-34. Go ahead, Ms. MacFarlane.

MS. MACFARLANE: The calculation that we have shown represents NB Power's calculation in the evidence of 10.35 percent as the all in cost of debt versus the calculation suggested by JDI in the transcript. I might mention the differences, first on the numerator, which is the interest expense itself. Mr. Nettleton has you can see in the far right-hand column taken the finance charges in the audited financial statements only. And in order to ensure an accurate calculation of the cost of debt, some adjustments have to be made to that.

First off, line number 3, we have to adjust for the interest earnings on the pension fund because in the evidence those are actually reflected in OM&A.

Secondly, the capitalized interest has to be added back, because the capitalized interest is part of the overall cost of debt.

But more importantly we wanted to make the adjustment for foreign exchange. At the financial statement date, the historic deferred and amortized foreign exchange has been written off to retained earnings, which we have indicated in the evidence we think is inappropriate. It was a cash cost. It does need to be collected over rates. So we have added that into interest expense. And we have deducted the current year's translation expense. And the reason we have deducted it is we do not believe that the ratepayer should be paying for foreign exchange on interest based on the currency fluctuation. The volatility is too high.

And I might just mention that in the previous year that $4 million number would have been 82 million in one year because of the currency fluctuation. We believe that it should be deferred and amortized so as to smooth those costs for ratepayers. So we have made those adjustments to come up with a cost of long-term debt of 295.

When we look at the denominator, Mr. Nettleton has taken the total of the debentures out of note 10 in the financial statements. And that is what he has used as the denominator. And we have three differences in what we have used.

First, he has used the end of year balance and we have used the average of the beginning and end of year. Secondly, he has not taken into account the offsetting sinking funds, which are designated to be used only against this debt and he has not added in the avoided borrowing. But thirdly, and most importantly, he has not taken into consideration the need to account for the principle-related foreign exchange. And the principle-related foreign exchange, as it says in the note on the bottom, that and the interest-related foreign exchange must be translated into an effective cost of debt in order to be collected. If they are not included in the cost of debt, the foreign exchange costs would never be collected and the utility would not be able to service and repay its debt.

So those are -- that's the explanation of the difference in the two calculations.

MR. HASHEY: One more. I think the final one that I have today -- no, no, I am sorry. I am sorry. I am sorry. It isn't the final one. I have missed a whole page. The next one is --

CHAIRMAN: Shall we take a break, Mr. Hashey?

MR. HASHEY: As you see fit. I don't think they are going to be that long. I'm sorry, I have got five, six, not max to go on these.

CHAIRMAN: We will stick her out.

MR. HASHEY: Thank you.

MR. MARSHALL: Gordon is starting to worry.

MR. HASHEY: That's true. We wouldn't mind dragging this out a little bit. I think it's pretty obvious that the donation is going to go to the Empty Stocking Fund. But anyway on we go.

The next question on a serious note, the question was asked -- I believe it was asked of Ms. MacFarlane by Mr. Nettleton, I reference page 1,471 of the transcript. Have you considered what return on equity or return on capital rather would result if New Brunswick Power Transmission collected the 9.8 million in addition to its return on equity, but did not remit the 9.8 million, please calculate what the actual return on capital would be to New Brunswick Power Corporation. And we have a document to table on that.

CHAIRMAN: A-35.

MR. HASHEY: Mr. Chairman, can Ms. MacFarlane speak to this document?

CHAIRMAN: Please do, yes.

MR. HASHEY: Thank you.

MS. MACFARLANE: This is an update, an equivalent to table 14 (a) in my evidence which is the projected income statements for the period 2002 to 2005.

So if we were to look specifically at the column that is labeled "2004" you can see the revenues haven't changed, the expenses haven't changed, the finance charges haven't changed.

But we come down to "Payment in lieu of taxes." And where we had 9.8 million there is nothing there. So that means that the net income before profit-sharing is now 23.3 million. The profit-sharing is 8.1 million leaving a net income for the corporation of 15.2 percent -- $15.2 million which is 13 percent.

And if I could beg your indulgence. I know the numbers are very tiny. But if we could look at the table below for how we see that 8.1 million arising. You will see partway through this square table it says "Acceptable band of net income on average equity."

And the high end which is at 12 percent, is 14.1 million. And the low end which is 10 percent is 11.7 million. So between those two bands there is no sharing.

But between the 12 percent and the 14 percent, and you can see the ceiling of 14 percent is at 16.4 million, there is a 50 percent sharing. And then further down two lines, above the ceiling, there is 100 percent sharing.

So the calculation is the amount above the ceiling, i.e. the 23.3 million net income over and above the ceiling of 16.4 is 6.9 million. That entire amount gets returned to ratepayers.

The amount between the high end and the ceiling, i.e. between 12 percent and 14 percent, and that is between 14.1 million and 16.4 million, that amount is 2.3 million.

And as you can see below, 50 percent of that gets returned to the ratepayers, 1.2 million. And so the total amount returned is 8.1 million, which leaves us at the ceiling for the ROE of 13 percent.

And Dr. Morin had indicated that his sharing mechanism meant a floor effectively for the corporation of 9.5

percent and a ceiling of 13 percent.

MR. HASHEY: Thank you. Then I would move on to I think Mr. Porter probably on this one which is at page 1,537. And I think this question came from Mr. MacDougall. I don't believe he is here. But we will put this on the record and he reads it.

"Provide the supporting information that shows the breakdown of the ratio so that the Board is able to clearly understand that all of the functions of energy control centre related to transmission are discreetly set out."

I believe that was the question. I think we have a document on that. And then I would ask Mr. Porter to address that please?

CHAIRMAN: A-36.

MR. HASHEY: I may not have spoken very well to this. As you can see, the question I think on the document is a bit better expressed.

Mr. Porter, could you address this please?

MR. PORTER: Yes. I would just simply say that this confirms what we had stated on the record yesterday, that we have the accounting in place to track the transmission operation expenses separate from distribution, other than in the area of Information Systems where an allocation is required. And there is a group there that supports and maintains and develops software systems and the hardware that the software runs on.

And it has been negotiated between transmission and distribution that a sharing mechanism or service level agreement between the two business units ends up in 84 percent allocation of those costs to transmission.

And the end result here was that two-thirds of the O M & A for the energy control centre are allocated to transmission and the remainder go to distribution.

MR. HASHEY: Thank you, Mr. Porter. Move right along, Mr. Chairman --

CHAIRMAN: Please.

MR. HASHEY: -- so that Mr. Lavigne doesn't feel left out here today.

The question that I think was page 1,604 -- the question, Mr. Lavigne, I think you can answer verbally on this one.

"Does the Amortization Review Committee take into account the survivor curves to estimate average service life?"

MR. LAVIGNE: Yes. I have an answer to the undertaking. As a result of the undertaking I had a discussion with out accounting policy adviser. This individual is a member of the Amortization Review Committee.

This individual was familiar with the concept of survivor curves and also with the organization that Mr. Nettleton mentioned, i.e. Gannett Flemming. Our adviser actually has taken some courses from that particular organization.

So when I posed the question to the individual, he advised me that we at one point in the early '90's actually did use survivor curves as part of our analysis of amortization review. It was primarily on the distribution side of our business. We have never used it in the transmission side.

We subsequently stopped using survivor curves in -- I guess it was the mid to early '90's, as a result of I guess concern that we were not getting I guess the cost benefit, the value for money from using that particular concept, even on the distribution side.

In terms of transmission, our reasoning for not using survivor curves for transmission was the lack of historical computerized data to provide I guess a significant enough component for providing a statistical analysis of those curves.

In order for these curves to I guess be representative, you need a fair amount of data to carry out the analysis.

The other reasoning that we put forth is NB Power has fairly detailed fixed assets records compared to a lot of utilities, which allow us to determine service lives for I guess components versus overall assets.

MR. HASHEY: That is that one, Mr. Chairman.

CHAIRMAN: Yes. Thank you, Mr. Hashey.

MR. HASHEY: Okay. Excuse me just a second. Yes. The next one and the final one I think fortunately, we are down to an undertaking that Ms. MacFarlane gave which was "Provide a consolidated income statement as to March 31, 1990 and provide the calculation that was used to calculate the number." I think that was 9.5 percent embedded cost of debt.

And then there was an earlier one that I have missed, and maybe we could deal and mark them at the same time, which was "Where does the 1.21 kilowatt year come from on schedule 1.1, exhibit A-2, appendix B, attachment B, page 68?"

And there is a calculation. There would be two documents that we can enter. And I would ask Ms. MacFarlane to speak to those documents.

MR. MARSHALL: Mr. Hashey --

MR. HASHEY: Okay. First of all then we will deal with the one I referenced first. That is the 1.21 issue. Would you please enter that one. And then I will come back to the other one.

CHAIRMAN: That will be A-37.

MR. PORTER: My comments will be very brief.

CHAIRMAN: You are not feathering your own next then, are you? I guess you are actually.

MR. PORTER: I am. Actually this is information that we did cover with Mr. MacDougall the other day. But we undertook to write it out in detail because it was a bit complicated to follow it through the schedules.

And it merely shows what we included in the cost allocation study as being the revenue that would be received by a generator for the provision of reactor supply and voltage control.

MR. HASHEY: If Mr. Nettleton suggests I should address this with an argument he can forget it.

MR. NETTLETON: I didn't ask the question.

MR. HASHEY: The next and final one, I'm sorry, is the undertaking that I spoke of for Ms. MacFarlane. It did come from Mr. Nettleton dealing with this 9.5 percent embedded cost of debt.

Has that been circulated?

CHAIRMAN: A-38.

MS. MACFARLANE: Mr. Chairman, what has been put before you is the requested income statement that matched half of the balance sheet that was put into evidence the other day on the basis of an undertaking.

The second half of this undertaking was to provide the calculation that was used to calculate that number, 9.5 embedded cost of debt.

That number was one Mr. Nettleton pointed to in appendix 5 of the December 6th 1991 decision.

And staff in Fredericton went back to the evidence that was submitted in the 1991 hearing. And that number was in that evidence as the rated average coupon rate of the debt.

It was not reflected as the all-in cost of debt. And frankly there was no need to have an all-in cost of debt expressed as a percentage at that time. Because the regulatory framework was cost of service, not rate-based concept.

So if one looks in that evidence and looks at the dollar cost of service for interest expense, it does include that weighted average coupon rate. But it also includes the same calculation we have here, that being the amortization of issue cost premiums and discounts, the amortization of foreign exchange offset by a sinking fund.

So the percentage used in appendix 5 was a number that was referenced in the debt in the evidence but not referenced as an all-in cost of debt. It was the average coupon rate for the debt.

MR. HASHEY: Mr. Chairman, I'm pleased to say that completes all we can do today. I guess the only outstanding issue is the issue that was raised by Mr. Nettleton this morning that you will give us some guidance on and the issue of, you know, when we should have these other undertakings in and how you would like us to supply those.

CHAIRMAN: Well, certainly as far as the undertakings are concerned that I requested of this panel, there is no great urgency in those. They can be after the JDI evidence is concluded, as far as I'm concerned. But JDI may want to have them --

MR. NETTLETON: Mr. Chairman, there has been quite a few undertakings that have just been provided. And I know that this is the last day of the week. My advisers have all left Saint John.

I'm quite clear almost -- there is no doubt that there will be arising questions associated with the undertakings that have been provided. I can start. But I would rather not take that step now in light of the time of the day.

But I do need to seek instructions from my clients on the undertakings that have been provided. Because I'm without a doubt sure that there will be arising questions, simply on the undertakings.

CHAIRMAN: Any comments, Mr. Hashey?

MR. HASHEY: Ouch.

CHAIRMAN: Yes.

MR. HASHEY: And that is fair. And obviously Mr. Nettleton isn't prepared. And I think we all too tired today to really gain very much from further questioning probably. But I guess if you want this panel back to answer questions, that is something we will have to do.

If it is something that Mr. Nettleton can determine that he could send off requests for further information or questions arising, we could probably entertain it that way as well, whichever is best for the Board.

CHAIRMAN: Yes. I would suggest, Mr. Nettleton, that you, as a minimum you would know which of the panel members your questions would be directed to.

MR. NETTLETON: Yes.

CHAIRMAN: And you could let Mr. Hashey know that. The Board considered over lunch. And I was going to mention it when we came back. Then I thought I would wait and see if anything ensued. And we appreciate your client's concern, Mr. Nettleton, about having to come twice.

But we feel relatively, as relatively confident as we can be, that the legislation will be in a form that is reasonably close if not exactly the same as NB Power has speculated that it will be, knowing how government members and NB Power members sometimes curl together.

Anyhow, on a serious vein, we think we should stick with the schedule that we had laid down. And we will ask JDI to be prepared to go ahead on Monday the 6th.

I would suggest that the questions in reference to the undertakings, Mr. Nettleton, perhaps Mr. Hashey can make those of this panel who are necessary to be here at the commencement of the hearing on Monday the 6th, so that you can put your questions to them before you call your evidence.

Now I do have something that I want everyone, particularly NB Power to comment on. I mean, you know, your job is rapidly coming to a conclusion. And ours is rapidly, as you would say in the power business, ramping up. Because we are going to have to make a decision to go through the evidence.

So frankly the Board is -- we will be back meeting the week of the 13th regardless if we have a hearing or not. And my intention would be not to have a hearing on the week of the 13th.

And that would then -- if we are fortunate enough to have the legislation come down during the week of the 6th then Mr. Hashey will have his week for preparation. And we would come back on the 21st which is a Tuesday and start with summation.

But my question of the parties in the room now is would we be better off in simply saying we will -- after JDI's evidence concludes -- and I'm going to suggest as well that we have, immediately after that we have the Informal Intervenors make their presentations to the Board. We will get that over and done with.

Would we be better off adjourning then until the week of the 27th for summation, which would then give Government and extra -- well, they would have at least up until the 24th to get the legislation in.

I shouldn't say the 24th. Because we are all going to have to have time to look at it. But it gives more time to get it in. And then we can all look at our calendars and plan much better, doing that.

Mr. Nettleton?

MR. NETTLETON: Mr. Chairman, I mentioned this this morning. And I wish to impress upon you the real concern that we have for maintaining a placeholder after the legislation has been at least introduced.

We recognize that it won't even be passed, but at least introduced, so that we have the opportunity to review it and have the opportunity if necessary for the reexamination of panels should that need arise.

CHAIRMAN: Yes.

MR. NETTLETON: And again, with no disrespect, sir, we do need that opportunity in order to ensure that principles of natural justice, of know the case that must be met are ensured in this proceeding

CHAIRMAN: I have no quarrel with what you said at all, none whatsoever. I'm simply trying to -- and frankly what is going to happen is when the legislation does come down is that the Board is going to have to be in touch with the parties.

And by e-mail find out what you think, how long you need and when it is that we can reconvene and whether or not we need to have the opportunity to recall witnesses. It is as simple as that. And we will certainly do that.

But in the interim shall we tentatively say now that if the legislation has not come down by the time we break in the week of the 6th that we will adjourn till the 27th?

Mr. Hashey, it will be your client I think that will be most concerned about that.

MR. HASHEY: That is fine. That sounds fair.

CHAIRMAN: We will proceed on that basis then. And the Board will be in touch with the Informal Intervenors and let them know that upon the conclusion of JDI's evidence with cross, et cetera that we will ask them to address the Board in that week of the 6th.

Mr. Nettleton?

MR. NETTLETON: Just so I am clear, we will proceed the week of the 6th and then we will adjourn and then summations will happen on the 27th.

CHAIRMAN: Yes, if -- that's right, that is subject to the legislation coming in in sufficient time for everybody to review it and et cetera. In other words hopefully we will get it during that week of the 6th.

MR. NETTLETON: So if it does come out the week of the 6th when might we have the opportunity to re-examine the witnesses?

CHAIRMAN: Well if it's necessary.

MR. NETTLETON: Yes.

CHAIRMAN: We will probably look at the 27th or depending on timing, you know. We may have to get on a telephone conference call to do it properly to find out when it is and what's up. Did you find out from your witnesses if -- for instance are they available in that week of the 27th?

MR. NETTLETON: They will make themselves available when we need them for this very important proceeding.

CHAIRMAN: Okay. Thank you. Well I guess you --

MR. MACNUTT: Mr. Chairman --

CHAIRMAN: Mr. MacNutt.

MR. MACNUTT: Yes. Procedural point.

CHAIRMAN: Oh, oh. It's too late in the afternoon, Mr. MacNutt.

MR. MACNUTT: Completion of balance of undertakings by NB Power, would it be possible to have them not later than January 3rd, preferably Friday the 28th, so that they can be reviewed in time for meaningful use.

CHAIRMAN: I think you are asking an awful lot. I think they will do the best that they can, Mr. MacNutt, and we will certainly go along with that.

MR. MACNUTT: Well perhaps could they circulate them as they become available rather than holding them, so that we have an opportunity to review them prior to the opening of the hearing on January 6th.

As well, Mr. Chairman, as they are supplied will better enable us to determine which of the four panel members of Panel C we would like to have return.

MR. HASHEY: I think I should have Ms. Tracy speak to this.

CHAIRMAN: I don't think so, Mr. Hashey. Are you prepared to live with what I said, that you will do them as quickly as you can and circulate them that way.

MR. HASHEY: Absolutely, we will. No question.

CHAIRMAN: All right. Fine. With that --

MR. MACNUTT: Further to that, Mr. Chairman, there are a number of undertakings from previous panels, not only Panel C, that we still haven't received.

MR. HASHEY: Maybe Mr. MacNutt should set those out because I don't think there are any, that I know of.

CHAIRMAN: Could you have those ready by 5:00 o'clock, Mr. MacNutt?

MR. HASHEY: If he would send those along to me. We don't need to drag this out today. You know, we have done the best we can. There has been a tremendous number of undertakings asked for.

MR. MACNUTT: We will review them and advise.

MR. HASHEY: A lot of them relate to the filing of the amended tariff. That won't be done by the 3rd of January, I can assure you. That is not stuff that is going to be cross-examined on.

CHAIRMAN: No. Frankly, Mr. Hashey, on that as far as I'm concerned if you are prepared to have it let's say a day or so in advance or at the same time we start summation --

MR. HASHEY: That's true.

CHAIRMAN: -- so that we can take a look at it and discuss it, I don't think there is any necessity for witnesses or anything else. That's just really a housekeeping item, as it were.

MR. HASHEY: That's a good idea. Thank you.

CHAIRMAN: Okay. Well I want to include translation services and the audio technician and the shorthand reporter in our wishes for everybody to have a very excellent Christmas, and that 2003 be prosperous and healthy for everyone here.

Thank you very much for your co-operation and we will see you on the 6th of January at ten in the morning.

Thank you.

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

Reporter