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New Brunswick Board of Commissioners of Public Utilities

In the Matter of an application by NB Power dated January 8, 2002 in connection with a proposal for Refurbishment of its facility at Point Lepreau.

Delta Hotel, Saint John, N.B.
May 28th 2002, 9:30 a.m.

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CHAIRMAN: David C. Nicholson, Q.C.

COMMISSIONERS: Robert Richardson
Ken F. Sollows
Jacques Dumont
H. Brian Tingley

BOARD COUNSEL Peter MacNutt, Q.C.

BOARD SECRETARY: Lorraine Legère

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CHAIRMAN: Good morning, ladies and gentlemen. Before we get started I had a couple of preliminary matters. The Board has received a draft of the DSM expert's report in. And we expect to have the final within the next 24 or 48 hours. So we will report to you when we get that. Yesterday I misspoke myself, probably because I couldn't read my own writing. But Commissioner Richardson pointed this out to me on page 105 of the transcript at the bottom, was talking about the financial projection

from March 2001 to reflect the current estimate of the results of the 2001/2002 year. The update should also reflect any significant changes that -- and I say sorry, charges. In fact it was changes.

Mr. Hashey, yesterday the Board indicated that we should redact slides 14 and 15 from I think it is A-16. And I left it open that if basically NB Power wished to make argument that they should be included that we would listen to that argument.

Do you have any intention at this time? Or shall I have the Secretary tear out the pages?

MR. HASHEY: I think you can remove them.

CHAIRMAN: Okay. Fine. We will do that. And what is the status of the CCNB's request for the video from NB Power?

MR. COON: Mr. Chairman, I have received a copy. And I think it well illustrates the complexities involved. And we would like to refer to it during cross-examination if we could.

CHAIRMAN: Any problem with that?

MR. HASHEY: No problem.

CHAIRMAN: Okay.

MR. HASHEY: Actually that was supplied to Mr. Coon last evening. We were able to locate one copy of the complete video.

MR. HASHEY: Yes.

CHAIRMAN: Okay. Thank you. Now any other preliminary matters before Mr. Coon commences his cross?

All right. Go ahead, Mr. Coon.

CROSS-EXAMINATION BY MR. COON:

MR. COON: Thank you, Mr. Chairman. I would like to begin with -- and good morning. I would like to begin with just a circulation of some exhibits that I would like to have marked. The applicant, Mr. Chairman, has received copies yesterday of the exhibits.

MR. HASHEY: I object to the marking of these documents as exhibits. If I could speak to that. I have no problem with Mr. Coon marking newspaper articles as for identification for purpose of cross-examining on them. But to put them in as evidence I don't think is appropriate.

If Mr. Coon wishes to give evidence Mr. Coon should have entered evidence. And that wasn't done. But mark them, I think we are talking about maybe semantics to a point.

But there are three documents. Two were newspaper clippings. And the third -- sorry, one was a newspaper

clipping entitled "Watchdog Questions Lack of Lepreau Project Assessment." The second is a globeandmail.com, "Problems Push Back Pickering Reopening." And the third was a set of numbers that I think Mr. Coon has prepared from the NB Power evidence.

And maybe I'm talking semantics here. But I think to put them in as evidence would be to agree with the contents of these articles. And we certainly don't --

CHAIRMAN: Mr. Coon, not being a lawyer yet acting very much like one on a lot of occasions, do you understand the difference that Mr. Hashey is making there?

In other words, it would be on the record. And you could therefore use them in your cross-examination even if they were simply marked for identification. So the witness could refer to it. And you could question him on what is in it, that sort of thing.

If it is put in evidence then, as Mr. Hashey says, normally that means that it has been accepted for the truth of what is stated in it.

Now this is getting very legalistic here. We have on occasion marked things as exhibit, Mr. Hashey, and simply said we will give them the weight that we believe they deserve.

But certainly this is an appropriate thing to ask for

at this time. Do you have any problems with that?

MR. COON: No. Simply I guess my point would be to have them marked so that I can cross examine, in a cross-examination refer to them and refer the witnesses to them.

CHAIRMAN: Yes. Well, that certainly, Mr. Hashey, is no --

MR. HASHEY: That is not a problem.

CHAIRMAN: -- no problem with that. How do we mark those, Mr. Hashey? Marked for identification 1, 2, 3?

MR. HASHEY: I would think so.

CHAIRMAN: Yes.

MR. HASHEY: Okay. ID 1, ID 2, ID 3.

CHAIRMAN: All right. Pardon me. The two-page document, the first page of which is newspaper article headed "Watchdog Questions Lack of Lepreau Project Assessment", and the second page has a couple of articles, the top one is "U.S. Governor Questions Nuclear Plant Wisdom", that two-page document is marked for identification number 1.

Looks like a printout of The Globe and Mail's website, the article is headed "Problems Push Back Pickering Reopening" is marked for identification 2.

And as Mr. Hashey characterized it, it looks like figures that somebody has compiled and put on a page. And it is headed "Point Lepreau Experience, 1983 to 2002, Cost of Repairs, Corrective Maintenance and Non-routine Capital

Improvements." That is marked for identification 3.

MR. COON: Thank you, Mr. Chairman. I would also ask how I should refer to these pipes over here, which I would like to refer to during cross-examination. Are they to be marked? Can they be marked as well, so I can have a number?

CHAIRMAN: I -- when they did the Esso pipeline across the South End of the City of Saint John they had about a foot length -- no, about a 6-inch length of the 12-inch pipe that was superwrapped and all that sort of thing.

And I had marked that because it made an excellent back anchor for my boat. But I don't think a Calandria tube will work and a fuel bundle.

Can't you just refer to them as -- the smaller one I understand is a mockup of a fuel bundle. And the other one is what?

MR. PILKINGTON: Fuel channel assembly.

CHAIRMAN: They haven't been used. Would that be sufficient?

MR. COON: Very good.

CHAIRMAN: Are we able to do that?

MR. COON: I wasn't going to ask for copies. But it was just for ease of reference.

Q. - Okay. I would like to begin just with a couple of

questions regarding some things that were raised in exhibit A-16 during the presentation yesterday that just sort of cropped up.

On page -- sorry, slide 13, the title is "Planning Conclusions". Here and in a number of places there are claims made about environmental performance of Point Lepreau.

Now a number of claims were made throughout this exhibit and --

CHAIRMAN: Just a minute, Mr. Coon. Let's give the technician a chance here.

MR. COON: Okay. We have got lights. We have got tapes. We have got microphones. Okay.

So we are talking about exhibit A-16, the slide deck from the presentations yesterday. And I wanted to start off -- on slide 13 there is a comment about environmental desirability of a refurbished Lepreau here. And also that appears in various parts of the prefiled evidence A-1.

As this -- as your are the economic regulator, I guess it is a procedural question, Mr. Chairman. And that is -- I mean, I could cross-examine on these matters. But this is not the purpose of this hearing. So I'm wondering what the status of this information is in evidence.

Is it indeed accepted as part of evidence, that is

assumed to be true, as Mr. Hashey just noted in regards to the newspaper articles that we have just marked for cross-examination purposes? Or how is it to be dealt with? Because there are frequent claims made around environmental performance.

CHAIRMAN: There is a lot of evidence that is given during one of our hearings that is not technically relevant to the decision that we are going to be making, all right. And we do not consider matters that are outside of our jurisdiction when we arrive at a decision.

So it is just part of a background package that has been put in. We are not making any ruling as to whether or not we believe this or we don't. You know, it would almost be impossible to attempt to be strictly limiting what can or cannot be said in our jurisdiction.

Now that doesn't answer very much. But I guess maybe what I'm saying is that we have no jurisdiction over the subject matter. We are not paying any attention to it.

MR. COON: Okay. Thank you, Mr. Chairman. Therefore I will not cross-examine on any of that information.

Now if we change to slide 33, the same exhibit.

Q. - The first point under the importance of Lepreau to NB Power it suggests this is its largest single unit, and I'm wondering, Mr. White, whether that is a good thing or a

bad thing?

MR. WHITE: Certainly it's good when it's running well and when it doesn't operate as it's predicted it's very hurtful to the Province in that you have to replace the power for it. So as a large unit the replacement power costs are high. So when Lepreau runs well it supplies economic energy to the Province and that's a good value to the customers in the Province. And if we have unplanned outages for it, then the impact is quite significant and felt immediately due to the replacement power costs, the differentials between Lepreau and the thermal units that may have to replace it.

Q. - So this is an issue around size, not the nature of the technology, but size, having such a large unit on the system can create problems, is that correct?

MR. WHITE: Well the unit has to be accounted for on the system in terms of being able to back it up when it's not there, of course. And so that's a capacity issue, okay. And then the energy issue is the value of the units of energy.

Q. - If you had -- if NB Power had its druthers with regard to its largest single unit, what would be the ideal sort of maximum size for a single unit on the system?

MR. WHITE: Well I think that's a question that would be

Panel B in terms of what kinds of units and what sizing fits the system.

Q. - Thank you, Mr. White. Okay. I think the rest of the things that cropped up from the presentation yesterday can pick up in my cross as prepared.

Now this is for you, Mr. White. At various points in your evidence -- sorry, in general at various points in the evidence exhibit A-1 different cost estimates are given for the estimated cost of the refurbishment project. I have got a few questions here which I hope will assist in sorting out the different estimates.

If we could turn to exhibit A-1 on page 5 of the prefiled evidence --

MR. DUMONT: Page 5 of Mr. White's evidence?

Q. - Mr. White's evidence, yes. On page 5 of your direct evidence, Mr. White, it states that -- you state that the estimated cost of the project including escalation and interest during construction is $844.6 million, is that correct?

MR. WHITE: That's correct.

Q. - The evidence further indicates on the page that the incremental capital cost is 785 million if Phase 1 costs are already expended are excluded. In other words, if we exclude what has already been expended for Phase 1 the

incremental capital costs are 785 million.

MR. WHITE: That's correct. That's the going forward cost.

Q. - Okay. Now further clarification on this question is provided in exhibit A-5 in response to one of our interrogatories. That's page 62 of the interrogatory -- I shouldn't say interrogatory, there is lots of volumes called interrogatories -- of A-5, CCNB-5.

This is going to be difficult cross-examination, I'm afraid, having to move back and forth between these various binders but I will try and take my time so that people have adequate time.

So here it indicates in response to an interrogatory that 59.6 million -- the 59.6 million dollar difference between 844.6 million and 785 million is made up of two components, interest during construction and overhead, is that correct?

MR. WHITE: That's correct.

Q. - So then am I correct in concluding that a particular cost estimate will depend on the assumptions used as to what is included, specifically whether one includes interest during construction, costs already expended, costs of replacement fuel during refurbishment and whether we are counting in current dollars or the constant dollars of the base year. These things will vary, is that correct?

MR. WHITE: There is no replacement fuel in these numbers.

Q. - We will get to that.

MR. WHITE: The numbers that are given are end of project numbers, so the total dollars spent over the life of the project, and when you compute those numbers you have to include the interest during that period of time.

Q. - I'm simply asking that the point -- to clarify the point that the cost estimate will vary depending on what you include in that cost estimate?

MR. WHITE: Well that's true.

Q. - Thank you. Now regarding the estimate of 844.6 million, the evidence indicates that it includes the Phase 1 cost interest during construction, as you have already agreed. Could you clarify for me if that 844.6 million estimate is in current dollars or 2006 dollars as is sometimes used in other parts of the evidence?

MR. WHITE: That's in end of project numbers. That's 2007, September.

Q. - 2007 dollars. Thank you. Could you also clarify if the 844.6 million cost estimate includes the purchase of replacement fuel that will be required during the refurbishment process?

MR. WHITE: No, it does not.

Q. - Thank you. Now I would like to put this book back and

turn to exhibit A-6. A-6, in the latter half of A-6 is response to CCNB-102, that's the tab, and these are Board minutes. Now they are not numbered, which is no reflection on Ms. Tracy at all, so she shouldn't feel bad about that. She has done a tremendous job.

But I would like you to turn to the sort of last one-third of that tab, of the minutes, and specifically the second to last subsection divided by the blue pages for the meeting of December 18th 2001. So it's right towards the back. In fact in my binder it's the second to last -- okay. Where I want you to go is -- it's entitled Part 2, Business Case, page 9, for that meeting date December 18th 2001, project cost estimates.

CHAIRMAN: That's under the Point Lepreau refurbishment portion of the minutes?

MR. COON: That's -- yes.

CHAIRMAN: There is a heading in here, we have got that, on page 8.

CHAIRMAN: Page 10 is where you want us to go I guess.

MR. COON: Page 9 is actually where I was asking you to go. It's 14 pages from the last page of the exhibit.

CHAIRMAN: Well it's headed -- we have a page 9. Mr. White presented an update on pressure tube life limits.

MR. COON: Oh my. It's the second page 9.

CHAIRMAN: It's the second page 9. We have all got it, thank you, Mr. Coon.

Q. - Okay. So this page provides information on the estimated cost of the refurbishment project as presented to the NB Power Board of Directors. Information from the Board meeting indicates the total cost is $904 million -- total as built cost $904 million according to the bracket at the top of this figure 2000/2001 dollars. Now this figure of $904 million is significantly different from the 844.6 million that we referred to on page 5 of the prefiled evidence in exhibit A-1. So I guess my question here is which capital cost estimate is correct, the $904 million estimate given to the Board of Directors of NB Power or the $844.6 million given as evidence at this hearing? Which is the right one, Mr. White?

MR. WHITE: $845 million is the right number. The $904 million as presented in this case was corrected in subsequent Board meetings for an error in the escalation amounts and actually was corrected to the $845 million.

Q. - So just to be clear, can you repeat the difference between the two estimates?

MR. WHITE: There was -- on the line escalation in that business case page 9 it says 123 million. There was an error in calculation of that number over the time frame

and it was subsequently corrected in a subsequent Board meeting to confirm that the total as built cost was 844.6 million.

Q. - Okay. Thank you. That clears that problem up. Now – so we are working with 844 million cost and as you said, that doesn't include the cost of replacement power over the 18 months you are projecting the work to take.

MR. WHITE: That's correct.

Q. - So if the work goes forward and it only takes 18 months, what would be the cost of replacement power, or what are you estimating?

MR. WHITE: Let me get the context straight here, please. The context for Lepreau is that it finishes its life in 2006. And so at that point time you either have to decide you are going to refurbish it or alternately shut it down and replace it with something else. So in fact in the normal understanding of replacement power, it doesn't occur. The plant just isn't there. Now what are you going to replace it -- what are you going to use as the new source of generation for this province. The new source could be refurbishing Lepreau or the new source could be some other alternative such as gas or Orimulsion.

So it's not replacement power in the normal sense that we are down for an outage and we have to replace it then.

Q. - Well, Mr. White, yesterday you told us that you would have to have a decision on whether to refurbish Point Lepreau by this fall, is that correct?

MR. WHITE: That's correct.

Q. - And if the decision was made to not refurbish Point Lepreau you would have to -- if you were to build a gas fired power plant to replace -- or to provide the needed electricity for 2006, when would that planning take place and when would construction begin?

MR. WHITE: The decision were negative on this application then planning would take place immediately and occur during the period from now until 2006 to accomplish construction, installation and operation of an alternate source.

Q. - So in fact that alternate source will be constructed while Point Lepreau is still operating and generating electricity?

MR. WHITE: Yes.

Q. - And that alternate source would then be available and on line when Point Lepreau would be retired?

MR. WHITE: That's correct.

Q. - So in fact in 2006, if the decision is made to go ahead and refurbish this year Point Lepreau in 2006 you would have to provide replacement power while it's down because

there is no other unit -- I mean that would be a requirement, isn't that the case?

MR. WHITE: We would have to provide a source of generation going forward from 2006, that is correct.

Q. - You described also yesterday the reconstruction project at Point Lepreau as essentially a maintenance outage. Don't you have to purchase replacement power during maintenance outages?

MR. WHITE: During normal replacement outages we would -- excuse me -- during normal maintenance outages we would buy replacement power or provide it ourselves, that's correct.

Q. - So the question is what would the cost of replacement power be over the 18 month period that Point Lepreau would be reconstructed if that's what it takes?

MR. WHITE: Again the power requirements during that period of time from an alternate source would be the details of Panel B. In rough terms it costs about $200 million a year to replace Lepreau. So for a year and a half you are talking about $300 million.

Q. - And in what year -- are those 2007 dollars?

MR. WHITE: Those would be based on current costs.

Q. - Current costs. So in 2007 dollars that would be how much?

MR. WHITE: Well again it depends on the source of the generation at that time. As I say, that would be a Panel B question but I gave you the rough numbers.

Q. - I'm just looking for -- I mean you have talked about the cost of the project here and you have given us a number in your evidence of $844 million in 19 -- or 2007 dollars, and I'm simply trying to get a full picture here of the cost of this project if it were to go ahead. So there is the cost of the work and then there is the cost of the power while you are doing the work. So what would the cost of the power in 2007 be if it were 300 million in today's dollars?

MR. WHITE: Well again that power has to be supplied regardless of which source it comes from. So in the true sense of making the decision relative to Lepreau it -- the life ends in 2006 and then the alternate source takes over, whatever that is. If the alternate source in this case happens to be a positive decision on refurbishment, then that is the source that supplies it.

Q. - Let me ask one last time --

MR. WHITE: Yes.

Q. - -- and then that's it. Can we get 300 million in 2007 dollars?

MR. WHITE: I think what you are trying to address here is

that the alternative to Lepreau, okay, has a different cost, and if you use the -- if you substitute a different source of power for Lepreau in that period of time, then it has a different set of costs.

Q. - Right now all I'm trying to get at is what $300 million in today's dollars would be in 2007?

MR. WHITE: I don't have that answer for you, sir.

Q. - Thank you. Let me ask this, what would the $844 million cost of Point Lepreau refurbishment in 2007 dollars be in today's dollars?

MR. WHITE: 633 million, I believe, is the number. In your reference to the business case on page 9, we were talking about -- we started this question. You see the sub-total of $627 million?

Q. - Yes.

MR. WHITE: That would be the cost in today's dollars in terms of overnight costs. To that you then add the escalation and the IDC and you come up with the 844 million.

Q. - Thank you. So in today's dollars then it would be correct to say that the total costs in 2001 dollars of refurbishment plus replacement power would be $927 million? I just added the two.

MR. WHITE: I don't look at it that way because you have to

deal with the alternatives, but if you chose to do it that way.

Q. - Thank you. I would like to take you back to the pre-filed evidence, exhibit A-1. On page 2 you say refurbishment and life extension is increasingly -- sorry, page 2 of your evidence, Mr. White.

You say that refurbishment and life extension is increasingly viewed as a competitive alternative. And then on page 3 you note that Ontario Power Generation is in the process of returning four Pickering A units to service.

Is the work proposed for Point lepreau comparable to that carried out at the Pickering A units?

MR. WHITE: No, it's not.

Q. - No. So this notation about OPG returning four Pickering A units to service is not an example of refurbishment and life extension?

MR. WHITE: My understanding of the Pickering work is that it is intended to bring the unit back on line to serve the remainder of its existing life.

Q. - Thank you. So it's to help it complete its existing life rather than extending its life, is that correct?

MR. WHITE: That's my understanding.

Q. - So it wouldn't be an example of what's being proposed for

Point Lepreau, which of course is completing its existing life and you are proposing to extend that out 25 years?

MR. WHITE: Types of work being done are somewhat similar, but the reason for the work and the duration is different.

Q. - Has the work proposed for Point Lepreau ever been carried out on any CANDU reactor anywhere?

MR. WHITE: Yes.

Q. - Has the replacement of Calandria tubes on a production basis ever been carried out anywhere on a CANDU reactor?

MR. WHITE: I will ask Mr. Groom to answer that.

MR. GROOM: There have been individual Calandria tubes replaced in the past.

Q. - Has there been work done to replace Calandria tubes in the entire Calandria vessel? In other words, on a production basis.

MR. GROOM: The -- I believe there have been some examples done on research reactors at Chalk River where full fuel channel assemblies have been replaced.

Q. - And are those -- how big are those reactors?

MR. GROOM: Say again?

Q. - How big would those reactors be?

MR. GROOM: How big are those reactors?

Q. - Yes.

MR. GROOM: I don't remember exactly but my recollection is

that they are in the order of 70 megawatts.

Q. - And the physical size of the Calandrias in those examples?

MR. GROOM: The Calandria vessel?

Q. - Mmmm.

MR. GROOM: I don't have that detail.

Q. - The --

MR. GROOM: It would be smaller than Lepreau but the fuel channel assemblies would be a similar size.

Q. - So this was -- and did they use similar equipment to what is planned for Point Lepreau?

MR. GROOM: The technology involved would be similar, yes.

Q. - Can you give us the years that the fuel channel replacements were done on the research reactors at Chalk River?

MR. GROOM: I don't have the exact numbers. I will have to go back and check that. If you allow me to do that I will try and provide that information.

Q. - Can -- Mr. Chairman, I wonder if that could be an undertaking to provide the -- note as an undertaking?

CHAIRMAN: It sounds a lot like one to me. Is that fair, Mr. Groom, you will undertake to provide that in the hearing?

MR. GROOM: Yes.

Q. - And you mentioned on commercial reactors there may be instances of single Calandria tubes having been replaced. Can you give us the names of those reactors?

MR. GROOM: Sorry, I was -- would you please repeat the question?

Q. - Sorry. I'm just wondering -- you mentioned that some single Calandria tubes have been replaced on commercial reactors. I was wondering if you could just name those reactors where that work has been done?

MR. GROOM: Yes, it has, but again, if you allow me I will bring you the details because I don't have them with me now.

Q. - Thank you, Mr. Groom. I don't know whether this is for Mr. White or Mr. Groom then but has an attempt been made anywhere to essentially double the life of a CANDU reactor at the end of its operating life to life extend a CANDU reactor to operate for again as many years as its original life span?

MR. WHITE: I believe this unit is the first one to actually undergo life extension studies.

Q. - Thank you. On page 7 of the prefiled evidence, Mr. White, addressed the construction history of Point Lepreau?

MR. WHITE: The reference was page 17, is that correct?

Q. - 7. I'm sorry. In response to Question 7.

Can you -- this is in response to the question of detractors of the nuclear option may question Point Lepreau estimates by pointing to performance difficulties in the past and provide a brief overview of the history of Point Lepreau.

Can you briefly summarize the magnitude of the difference between the anticipated capital cost of Point Lepreau and its actual cost?

MR. WHITE: I believe the original numbers for Point Lepreau were around $684 million roughly. And there were pre-estimates before that as low as 400' and some million. And the actual in service cost I believe was in the order of 1.3 billion.

Q. - So it cost triple or double depending on which of those initial estimates you start from?

MR. WHITE: That is correct.

Q. - And can you briefly summarize the magnitude of the difference between the time for construction that was originally planned and the actual project length to in service?

MR. WHITE: I believe, and I'm going by memory here, that Lepreau construction started in the late fall of 1974. And it was intended to be in service in the fall, I think

it was October of 1979. And it actually was put in service in February of 1983.

Q. - So then it would be fair to say it was just about four years overdue?

MR. WHITE: That would be correct.

Q. - Now on page 7 you explain these staggering overruns and project delays by saying Lepreau was the first CANDU-6 to be completed, among other things.

But one of the reasons was it was the first CANDU-6 to be completed. Is that correct, it was the first one to be finished?

MR. WHITE: That is correct. There were three being built at the same time.

Q. - And you go on to say that that -- (Technical Difficulties)

CHAIRMAN: I think what we will do is take a 10-minute recess.

(Recess - 10:17 a.m. - 10:45 a.m.)

CHAIRMAN: Okay. Mr. Coon?

Q. - I was just looking at the c.v. of Ms. McKibbon and realized that she was an accountant.

I wonder, Ms. McKibbon, whether you could tell me what $300 million in 2001 dollars would be in 2007?

MS. MCKIBBON: Without a business calculator I couldn't,

Mr. Coon.

Q. - Thank you. Would you be able to provide that later today sometime?

MS. MCKIBBON: Yes.

MR. COON: Thank you. Mr. Chairman, I will just back up a tad here to kind of start again as a result of the loss of power and so on.

So just to kind of recap here, we are on page 7 and Mr. White's evidence. And he was explaining, where the evidence explains why the costs of Point Lepreau historically, why the costs doubled or tripled and why it took almost four years longer to complete than originally planned.

And in his evidence he gives a number of reasons including that Lepreau was the very first CANDU-6 to be completed.

So as he points out on page 7, line 25, this put NB Power in the unenviable and unintended position of being the forerunner in dealing with design issues and with approvals from the nuclear regulator, causing some of these problems.

Q. - So my question, Mr. White, for you is as this is the first time, the first attempt at a life extension of a CANDU reactor following the end of its life, would it be

correct to say that NB Power once again is in the position of being the forerunner in dealing with design issues with respect to life extension and with approvals from the regulator in reference to life extension in Canada?

MR. WHITE: Certainly it is the forerunner in life extension. Most of the kinds of things we are talking about here are not new designs.

They obviously are designed for this work. But they are the kinds of things that have in fact taken place in the industry before.

Q. - So NB Power would be once again in the position of being a forerunner. And you are saying not particularly with design issues.

But how about with approvals from the regulator with respect to a life extension in a CANDU reactor?

MR. WHITE: You are correct there, for approvals from the regulator.

Q. - On page 8 in response to the concern about, you know, why wouldn't the refurbishment project be subject to the kind of experience Point Lepreau had, one of the things you say is the scope of what needs to be done is a fraction of the initial construction work, is that correct?

MR. WHITE: That is correct.

Q. - Is the scope of what is proposed similar to that fraction

of the initial construction work or different?

MR. WHITE: Could you please rephrase the question?

Q. - Well, my question is, is the nature of the work that will be done similar to the work that was required in building Point Lepreau? Or is it substantively different?

MR. WHITE: Well, it is substantively different in terms of volume and complexity. The kinds of activities are not unlike what would have to be done in original construction.

Q. - During the original construction did the workers have to work in radioactive fields?

MR. WHITE: No, they did not.

Q. - During the original construction did you have to install the Calandria tubes into the Calandria vessel at the site?

MR. WHITE: No, we did not. The Calandria came tubed.

Q. - Did you have to install the pressure tubes inside the Calandria tubes during the initial construction at the site?

MR. WHITE: Yes, we did, on site.

Q. - So the Calandria tubes, the Calandria vessel, the reactor core arrived with the Calandria tubes intact. So you did not do that work. You haven't done that work before?

MR. WHITE: That is correct.

Q. - But you did install the pressure tubes within the

Calandria tubes on site during initial construction?

MR. WHITE: That is correct.

Q. - So you have experience with that? Okay. Thank you.

Now you said that the workers during initial construction didn't have to contend with radiation fields. What sorts of protective equipment would be used for workers at the face of the Calandria?

MR. WHITE: Maybe I will refer that to Mr. Pilkington.

MR. PILKINGTON: Normally the types of measures taken for work on the reactor face would involve putting in temporary shielding in areas where people would be spending significant amounts of time, limiting the work locations close to the face only for the work that needs to be done in that area, those types of things.

Q. - When workers -- are there occasions when workers have to leave the shielded area and work at the reactor face near the fuel channels?

MR. PILKINGTON: Yes, there are.

Q. - And how would -- what kind of protective equipment would they have to wear for that?

MR. PILKINGTON: I'm sorry. Could you repeat that question?

Q. - What kind of protective equipment would they have to wear in that situation?

MR. PILKINGTON: It really depends on the nature of the work

and the level of the radiation fields that they are working in.

You have to remember that for this operation the reactor would be completely defuelled first so that the radiation fields would be substantially lower than when maintenance is done on a reactor with fuel in.

Q. - In the case when the end fittings are off the fuel channel assemblies and work is being done to extract the pressure tubes, under those situations what sort of protective equipment would the workers have to wear?

MR. PILKINGTON: Not being involved in the actual project I don't actually know the work methods that would be used to extract the pressure tubes.

So I really can't comment on the proximity of people or the type of fuelling -- in the equipment or the protection that people would therefore wear.

Q. - Thank you, Mr. Pilkington. Mr. Eagles, would you be able to answer that as Project Director?

MR. EAGLES: There is a combination as was demonstrated in the short video clip yesterday, a combination of automatic tooling work and manual tooling work.

In addition on the platforms where the work will be taking place, shielding cabinets will be installed for locations where workers have to be -- the operation of the

tooling, the automatic tooling would be done by control cabinets which would be placed in the lower radiation areas.

MR. WHITE: Mr. Coon, I might point out that as part of that question, the video that was shown not only demonstrates the tooling to be used in the automation that Mr. Eagles referred to, but the analysis that is done in terms of the methodology includes radiation dose and the ability to limit the radiation dose to the lowest level achievable.

Q. - If I can get you to go to exhibit A-17 -- sorry, not A-17, A-16 -- my goodness, A-15. A-15 and 17 are in the same binder, I understand, is that right?

The Refurbishment Agreement is A-15, am I correct?

MS. LEGERE: No.

MR. COON: So I was correct at the beginning. All right. A-17, sorry.

Q. - On page -- appendix D, D-5, of the refurbishment agreement. It is right towards the back.

MR. DUMONT: Could you say it again, please?

Q. - Appendix D of the refurbishment agreement, D-5 towards the back. In D.3.12.4 on that page, it says, "The contractors will provide plastic air suits including gloves, foot coverings, hoods, air lines, compatible hard hats and communication equipments for all contractors

staff and sub-contractors. Can you explain, Mr. Eagles, under what conditions the workers would have to use these plastic air suits?

MR. EAGLES: Reference again D.3 –

Q. - .12.4.

MR. EAGLES: Yes. During the -- during the early part of the construction work, after the fuel is removed from the core, the reactor vessel pressure -- sorry, the heat transport system and moderator system would be drained of heavy water. But during the course of work where there would be heavy water present the use of plastic air suits is necessary to protect the workers.

Q. - What would happen in the occasion when during withdrawal of either the pressure tube or the Calandria tube got stuck and you had to send someone past the shielding to try and help unstick it during removal, would they be required to wear plastic air suits at that or just what you call browns?

MR. EAGLES: That would depend on the level of tritiated air in the local area. And again that is a determination of whether -- whether during the process at that time there is any heavy water present in the tubes.

The process of preparing for this refurbishment is to drain the systems and to flush the systems to ensure that

the heavy water has been entirely removed. So I guess I can't definitively answer that question. Because again, monitoring of radiation fields in the area would be undertaken and the decision at that time would be made as to what was the appropriate level of protection for the employees.

Q. - Thank you, Mr. Eagles. Now, I am just trying to get a picture here of the sort of work environment. This sort of mock up here, as was set earlier, wasn't -- isn't the actual length, is that correct, Mr. Eagles, of that fuel assembly?

MR. EAGLES: That is correct.

Q. - And I think it was said it was 20 feet?

MR. EAGLES: That is approximately correct, yes.

Q. - Approximately 20 feet long, which if we took a tape measure and ran it out it would look something like -- if you go to the corner here, that is 14 feet. Keep going. Okay, so 20 feet. You are dealing with tubes of about that length, 20 feet. Is that right?

MR. EAGLES: That is right.

Q. - Okay. Now, the other thing is that work would have to be performed off of platforms in the air. And I assume that has to do with the height of the Calandria that is there. Tell us how high off the ground workers might have to

operate during these activities?

MR. WHITE: It is in the order of about 20 feet as well.

Q. - So it is similar just in sort of two stories of a normal house high they would be operating?

MR. EAGLES: Yes. I would like to point out as well that the platforms that the employees would primarily be working off of are the fixed platforms -- sorry, removal platforms that are part of the fuel machine equipment. So these are large rigid platforms that would be used for that purpose.

Q. - And then the width of the Calandria face where they would be working would be approximately what?

MR. EAGLES: Again, the Calandria is a round vessel about the same width as it is high.

Q. - So we are talking about two stories high, 20 feet wide and the pipes 20 feet long. Okay.

Now, what sorts of numbers of workers would be involved in this process, the actual retubing part of the process?

MR. EAGLES: I don't have the exact numbers --

Q. - Rough?

MR. EAGLES: -- at this time. We have indicated in the evidence that AECL is -- I guess as well given us information on the number of workers that they would

expect there. Overall throughout the entire project about 450 person years of construction trade labour and 150 person years of AECL resources which include technicians to be working on this work.

Q. - But in terms of actual retubing operation how many?

MR. EAGLES: In terms of the retubing operation -- just one second. I don't have the specific details of the crew size. And I would only be estimating I guess if I was to give you a number at this point.

Q. - Would they be working in a relay system?

MR. EAGLES: The work is expected to be conducted on shifts, yes.

Q. - And what sort of exposure times would the workers be allowed there?

MR. EAGLES: I don't have the specific details here.

Q. - Who would supply those workers the retubing, retubing activities?

MR. EAGLES: As I mentioned yesterday during my presentation the work to be conducted in the retube managed by AECL will be a composite team of construction trade labour, NB Power employees and AECL technicians.

Q. - Okay. Thank you. Mr. White, during the eventual decommissioning sooner or later depending on the decision about the proposed project, will the pressure tubes have

to be removed from the Calandria?

MR. WHITE: Ultimately, yes.

Q. - Ultimately. And will the Calandria tubes also have to be removed from the Calandria as part of decommissioning?

MR. WHITE: Ultimately, yes.

Q. - If we could look at Mr. Groom's evidence for a minute in the decommissioning plan which is appendix A-5 in the prefiled evidence exhibit A-1.

In the appendix A-5, I would like you to turn to page 27 -- yes 27 and 28, there is a table, table-1.

MR. GROOM: You mean table 1, on page 27?

Q. - Yes. And it extends over to page 28. It's entitled "Summary of Annual Decommissioning Expenditures."

MR. GROOM: Yes, I have that.

Q. - So my question is, Mr. Groom, in what years would removal of the pressure tubes and Calandria tubes occur in this decommissioning plan?

MR. GROOM: They would be targeted to take place between the 32nd and the 42nd year.

Q. - You are not suggesting it would take ten years to remove the pressure tubes and Calandria --

MR. GROOM: No. If you want the exact year and the exact time, I will have to go back to look at the model. But it's my recollection that it would be done by the end of

the 35th year.

Q. - If you could -- if you could get back to us on the actual year that that activity would be expected to occur, we would appreciate that.

And the pressure tube and Calandria tube removal would be occurring in the same year, would it?

MR. GROOM: Would you repeat the question, please?

Q. - Yes. Would the Calandria tube removal occur the same year as the pressure tube removal in the decommissioning plan?

MR. GROOM: Again, my recollection is that they happen at around the same time. But the sequence would normally be to remove -- my expectation would be we would remove all the pressure tubes, and then remove all the Calandria tubes as a sequential operation.

Q. - And can you tell us what percentage of these costs in those years -- well, of course, you don't know what year, so you will have to get back to me on, that won't you.

What I am after as part of this question is what percentage of the cost for those years would -- would be expended on that activity, removing the Calandria and pressure tubes?

MR. GROOM: I don't have that detail.

Q. - No, but when you get the year from the model, then we can

look at your table and probably sort that out since it's detailed year by year expenditures.

So that you are roughly thinking it's around 35, so that's after roughly 35 years or dormancy -- of the reactor being dormancy -- dormant that this work would occur, removing the pressure tubes and Calandria. Is that correct, Mr. Groom?

MR. GROOM: Roughly. Again, I will provide you that information when I have the detail.

Q. - Thank you. What is the purpose of the dormancy period?

MR. GROOM: The purpose of the dormancy period is to provide radioactive decay an opportunity to reduce the radiation fields from the equipment that will have to be subsequent -- subsequently removed.

Q. - Thank you. So, Mr. White, the scope of the project you are proposing includes activities that would be part of the decommissioning program to dismantle the reactor, only without the dormancy period in front of it. Is that correct?

MR. WHITE: Some of the tasks are similar to decommissioning, yes.

Q. - And such dismantling activities have not yet occurred in any CANDU reactor at this point. Is that true, as part of decommissioning?

MR. GROOM: I think I will answer that. In the question you asked earlier this morning about Calandria tube removal and the experience we have had with that which information we are -- we are gathering and will submit to you later, I think I made mention of the point that full Calandria vessel removals and replacements have been done in other reactors, in other CANDU reactors. So we do have experience with that. That has been done over 20 years ago. So this technology has been in the industry in Canada for a large number of years.

Q. - But in essence, what is going on here with respect to the retubing part of the refurbishment project in removing the Calandria tubes and the pressure tubes, basically you are going to have to do -- if this goes ahead, you are going to have to do it twice. You would remove the pressure tubes and Calandria tubes for the refurbishment project, and then as part of the decommissioning plan you would do the same thing all over again?

MR. GROOM: Part of the basic design of the CANDU that makes it an advantage is the capacity that we can change fuel channels on an as required basis as needed. It's a little bit like planning a design so that you can change the used tire on a car. You don't throw away the car as a consequence of needing to change a tire. So the mission

here really is that we come up with a strategy that enables us do either single channels or multi-channel change outs. And we do have experience with that.

Q. - But, in fact, the proposed project will have you dismantling all of the pressure tubes and Calandria tubes from the Calandria vessel as will be required as part of the decommissioning plan?

MR. GROOM: That's affirmative. And I might point out that in my comment about the -- taking advantage of the radioactive decay, there are a large number of components of which the fuel channels are one. And the procedures which we have developed for retube and the flasking and what you saw in the display, we think provide an effective way that any time in the plant life we can remove Calandria tubes and pressure tubes and replace them.

Q. - Can we run the video now. And do we have the capacity with the machine to stop it so we can -- I can ask questions on particular parts of the video? Is that possible?

MR. EAGLES: I can put it in. I don't know if I can make it work.

MR. HASHEY: Mr. Chairman, do you wish to mark this video?

CHAIRMAN: I don't know how to do it.

MR. HASHEY: Just put a big sticker on it -- I don't know

whether it -- part of it wasn't shown yesterday if you need that. No problem.

CHAIRMAN: I'm open to suggestions, Mr. Hashey, frankly. I have not had to deal with video footage before in my checkered career as to how -- we can mark it and just put it in. I mean, that's -- that's no problem.

MR. HASHEY: Obviously it's not something that everybody would need a copy of.

Q. - Okay. Is it Mr. Eagles who is the appropriate person to answer questions on the video?

MR. WHITE: Yes, he probably could start.

Q. - Okay. So at the beginning as I understand it this video has basically got three parts to it. The first shows us how the pressure tubes would be withdrawn, which you have had experience with, although not on this scale, as you said, but you have removed pressure tubes before. The second part is how the Calandria tube, the outer tube is removed. And then the third part I believe shows the Calandria tube being reinserted, the new Calandria tube -- sorry -- the new one.

So the first part is the pressure tube coming out and this image we see here, this is what you refer to as the flask. It's on some kind of a crane but it's the flask that is going to receive the chopped up pressure tubes.

MR. EAGLES: Yes. This is a shielded flask for radiation attenuation of the irradiated material once it's cut up in the checkerboard press.

Q. - Okay. So the flask is set into position. Now what we are looking at here, that's the Calandria face where all the fuel assemblies are --

MR. EAGLES: That's correct.

Q. - -- that round area. And then the machine in front of it is the machine that is designed to extract the pressure tubes and chop them up?

MR. EAGLES: I believe that's correct, yes.

Q. - Okay. So the flask is moved into position. It's on wheels, is it? Oh dear. Now we are in trouble. I knew that was going to happen. Let's try again. Okay. There we go. Now this is -- the flask comes in -- you can't just put this stuff in a dumpster, right. You have to -- what we are seeing here is the machine getting ready to remove a pressure tube from the Calandria?

MR. EAGLES: Yes.

Q. - And this particular machine -- well not this one but, you know, the representation of this machine, this machine, has it been used -- was it used at Pickering in the retubing project there?

MR. EAGLES: No. My understanding is that at Pickering the

pressure tubes were removed in full length.

Q. - And was there a reactor that was retubed subsequent to Pickering?

MR. WHITE: Just to follow up that question, this machine was special built for this job.

Q. - Okay. So this is a brand new experience with this machine.

MR. WHITE: Yes. This is to attempt to deal with not having long flasks, to handle long length pressure tubes, but to cut them up. So it's part of the early tool development in the retubing contracts.

Q. - It hasn't been built yet though, has it?

MR. WHITE: Yes, it has.

Q. - Oh, it has. So where does it live?

MR. WHITE: In Chalk River.

Q. - And it was built at NB Power's cost or AECL's cost?

MR. WHITE: It was built at NB Power's cost as part of the Phase 1 work, definition phase.

Q. - You mean to say, Mr. White, that you have paid for a machine that you may not have to use if the reactor project is not approved?

MR. WHITE: We were -- we needed to properly be able to understand the scope of the work and the costs and the estimates and the ability to be able to properly retube

this reactor. And so as part of Phase 1 work we did invest in the development of this tooling.

Q. - Who gave the authority to make the capital expenditure on new equipment?

MR. WHITE: New Brunswick Power Board.

Q. - So therefore you own the machine and can rent it out to others presumably?

MR. WHITE: No, we don't. We have the licence to use the machine. It belongs to AECL.

Q. - You bought -- you paid to have the machine built?

MR. WHITE: That's correct. We paid as part of the Phase 1 work.

Q. - And AECL gets --

MR. WHITE: The development of the capability of initial tooling to be able to prove that we could in fact do a fast reactor retube, and this piece of tooling was part of that work. It belongs to AECL but it was developed to be used on this job if we needed it and if we went forward.

Q. - But why would you pay for a piece of sophisticated equipment like this and then just give it to AECL?

MR. WHITE: We are paying for the technology to be able to execute the job within the time frames that we have identified, and it's inappropriate for us to be able to identify the time frames if we are not sure if the

technology works. So we invested far enough to be able to assure ourselves that we have covered the risk that the technology would be able to work and be able to perform this within the time frames identified.

Q. - Isn't that like paying your architect to build your house and then you can go visit it every once in a while he lives in it?

MR. WHITE: Maybe like paying the architect to be able to build a model of the house so that you can confirm that you are satisfied with the dimensions and sizes and spaces and whatever that he laid out.

Q. - Well to be clear, this isn't a model, this is the actual machine that is to do the work?

MR. WHITE: They developed the prototype machine, yes, to do the work.

Q. - If it breaks down, the parts, are they off the shelf or do you have to fabricate replacement parts?

MR. WHITE: Most of the machine components are off the shelf. I mean obviously some of them are specially machined or specially fabricated for this kind of thing. This machine was built at Chalk River and there will be more than one of them in this job.

Q. - So there is more than one of these machines?

MR. WHITE: Yes. Not at this time but there will be

ultimately.

Q. - Sorry. Say that again. Will there be a single machine for this job or more than one machine?

MR. WHITE: There will be more than one to complete the actual work, but at this time it's my understanding they have only built one.

Q. - And will NB Power pay for the other machines as well?

MR. WHITE: We will pay through the retubing contract for all the tooling that is necessary to execute the work. We won't own the tooling but we will pay for the use of that tooling.

Q. - Wow, that's amazing. So AECL will own the other machines as well?

MR. WHITE: Yes.

Q. - Which then they can use for other customers?

MR. WHITE: Correct.

Q. - What is the approximate cost of this machine?

MR. WHITE: I don't know the answer to that. We paid as part of the Phase 1 work, I think about $6 million, $7 million, for early tooling development. So we didn't necessarily pay for all the costs of that, we paid for costs to allow that early tooling development to occur at this Phase and time.

Q. - And the cost of the subsequent machines you require

will -- are accounted for in the budget you have provided?

MR. WHITE: That's correct. They are in the retubing contract.

Q. - Part of the retubing contract. Have you purchased any other capital equipment or physical materials that will be used in the project if it went ahead besides this prototype machine?

MR. WHITE: As part of the ability to execute this kind of job and understand the complexities to be able to assess the sequence of doing the work, all this work has been computer modelled, okay. So part of our Phase 1 costs included that computer modelling. We don't own the computers obviously, but we have access to the rights to use the technology.

There will also -- there is also under construction at this time mock-ups of the -- in Sheridan Park, that's AECL's laboratory in Sheridan Park -- of the fuel channels and Calandria tube and reactor assemblies, to simulate the actual detail physicals within the field so that AECL can go through physical change outs, mock-ups, try out all these practices and procedures, tooling. So fully demonstrated. So they started the construction of those facilities in order to do that.

Q. - Okay. We will continue on. So here we are seeing this

machine extracting the pressure tube and then dicing it up into I think 50 millimetre squares that audio says -- well it crushes it first and then dices it into 50 millimetre squares which then fall into that concrete flask on the floor below, is that what is --

MR. EAGLES: All in the flask it falls, yes. This is an overhead view.

Q. - Yes. Looking down. And the dust from that activity is -- well anyway I won't ask that. Never mind. Okay. Now we are going on to -- that's the pressure tube. Now we are going on to the Calandria tube. So the pressure tube is removed in this diagram. How many fuel assemblies are there, 300-and-some-odd?

MR. EAGLES: 380.

Q. - 380. So this has to be repeated 380 times, is that correct?

MR. EAGLES: That's correct.

Q. - Okay. So the Calandria tube -- now the Calandria tube -- we know from the pipes here that the pressure tube sits in the Calandria tube and this sort of sets in there separated by those springs, I think you call them garters, or garter springs, the spacers --

MR. EAGLES: That's correct.

Q. - -- in the existing system. Now -- oh, I forgot to ask.

When the pressure tube is pulled out, does it actually look like -- does it look like that --

MR. WHITE: That's not an actual pressure tube. The actual pressure tube is slightly larger than that. But yes, that is typical of what it looks like.

Q. - So after 19 years it would look like that pipe?

MR. WHITE: Again that's not an actual pressure tube, but that's what the model simulates.

Q. - Well but after 19 years of operation does it look like new metal or does it look like something else?

MR. WHITE: Just dark coloured metal.

Q. - Dark coloured metal. And -- okay. So the Calandria tube however is different in that it's secured in -- help me here -- in the Calandria these trusses or struts I guess in there -- what do you call them?

MR. EAGLES: That's the tube sheet.

Q. - The tube sheet. Thank you. The Calandria tube is held by these tube sheets. That's how it's held in place?

MR. EAGLES: That's correct.

Q. - And it's just held by friction, is that --

MR. EAGLES: It's a rolled-joint.

Q. - Can you explain that?

MR. EAGLES: You use a roll expander to physically deform the tube into the grooves within the tube sheet so that it

has a leak-tight seal.

Q. - Oh it's sort of like putting --

MR. EAGLES: To expand the --

Q. - -- a cork in the bottle -- well that's not quite right. It's like putting something in -- an insert inside of it to expand the pipe?

MR. EAGLES: To expand the pipe

Q. - But it's friction that holds this --

MR. EAGLES: That would be correct, yes.

Q. - -- in the sheet?

MR. EAGLES: That would be correct. Interference with, yes.

Q. - So the first -- all right. So we are doing well here now. So the first thing then is these inserts that press the Calandria pipe up against the struts there, have to removed and that's what is happening here.

MR. EAGLES: That's correct.

Q. - So that loosens -- that's intended to loosen it up?

MR. EAGLES: That's correct.

Q. - Now those inserts are going into another sort of flask -- A. That's correct.

Q. - -- right there, which is to provide the appropriate level of radiation protection and so on.

MR. EAGLES: That's correct.

Q. - Okay. So that are they going to a separate flask. And

that's just the insert. So if we get the inserts out and does the Calandria tube -- remind me again. Have you taken out a single Calandria tube at Point Lepreau?

No, we have not.

Q. - You haven't. So is the Calandria tube expected to automatically loosen up and kind of jiggle around in those tube sheets?

MR. EAGLES: Jiggle around would not be correct, no.

Q. - Well what I mean was, you know when you take something apart, would it hold its shape and -- or would it slide out easily is my point?

MR. EAGLES: The process of releasing the Calandria tube insert is induction heating which would cause the rim to want to expand or would physically deform to a smaller shape when cooled, and that same heat is applied to the Calandria tube as well. So that it would loosen the fit on the -- on the tube sheet.

Q. - And this would have to be on over the entire 20 foot length of the --

MR. EAGLES: No, just at the tube sheets.

Q. - Just at the tube sheet?

MR. EAGLES: That's right.

Q. - Okay. So in spots. All right. So you remove these inserts to essentially loosen up the Calandria tube and

put them in these flasks, take them away. Now can you explain this Calandria tube anchor? Why do you have to anchor the Calandria tube at this point?

MR. EAGLES: We remove the Calandria tube insert at one end and as a consequence the rigid fit at the tube sheet does not exist at that end any longer, and we don't want when we release the Calandria tube at the opposite end for the Calandria tube to I guess become loose and potentially fall into the reactor. We anchor the Calandria tube in place so that there is no problem with its movement, and that supports the ability to remove the insert at the opposite end.

Q. - What if in one of these 380 times you have to do this the anchor didn't work for some reason properly and the Calandria tube did fall into the reactor, what are the implications of that?

MR. EAGLES: I don't have any detail I guess to be able to discuss that here today.

Q. - But you are concerned about it. You need to anchor it?

MR. EAGLES: We are concerned about it and that's why the tooling has been developed to ensure that this process goes well.

Q. - But are you concerned about it because if it falls in it's game over or are you concerned about it because it

would mean it would take further time to do the job? What of those two possibilities --

MR. EAGLES: I would not expect that it would be game over per se. This is -- and again as per the time it would fall within AECL's responsibility to correct that problem. But again, this is a very low probability type event and the appropriate level of tooling has been developed to ensure that it doesn't happen.

Q. - Yes, I understand, and that's wise, but I'm just trying to get at if it falls into the reactor what kind of difficulties does that create? Is that like something disappearing down a drain that you have to try and fish out, or is it -- you have to explain it in plain language.

MR. EAGLES: Again, if the tube had moved accidentally during removal at the -- of the Calandria tube insert at the opposite end, then the Calandria tube would still be protruding from the reactor core at that end. So I would not suspect that that would be significant detriment to the program and certainly not the intended process for it to be removed, but it would not have fallen completely down inside the reactor.

Q. - Okay. So you just have to sort out a way to --

MR. EAGLES: Yes.

Q. - -- withdraw it without the equipment? But can you

assure us that this eventuality has been looked at by someone?

MR. EAGLES: Yes. I understand that the holding device will be tested as well during its installation.

Q. - If a Calandria tube did fall in, you wouldn't be able to use this equipment to pull it out?

MR. EAGLES: Well again as I mentioned, because you are talking about a tube supported between tube sheets at either end, in order for one end to slip off the tube sheet on the inside, it will still be protruding from the opposite end, so again we don't believe that to be happening. As Mr. Groom has advised me, there is testing to take place to ensure the locking mechanism is in place, the anchor mechanism is in place and therefore we would not expect it and we don't see that it would be a big problem.

Q. - But if it did happen, I mean, would it be a couple of hours to fix or are you talking about a longer period of time?

MR. EAGLES: I really can't say.

Q. - You don't know. Okay. Now this -- okay, continue on. So we are anchoring the Calandria tube so it won't fall into the reactor. We are looking down. It's 20 foot length. It's anchored on both ends, is that what we are

seeing here?

MR. EAGLES: It still at this point has the Calandria tube insert installed in the opposite end, so it would be anchored at both ends.

Q. - Okay. And the other insert is taken out. And now we are about to remove the Calandria tube. These plugs on the end, are those for -- what's the purpose of those plugs?

MR. EAGLES: That's shielding plugs.

Q. - So it's to reduce the exposure?

A. Just to reduce exposure to the workers.

Q. - So when the plugs come off the radiation exposure goes up?

MR. EAGLES: It would go up marginally for certain. That's why the plug is installed.

Q. - Okay. So you sent in a guy to get the tools set up to withdraw the Calandria tube from its supports there. Now this machine is different than the one used to remove the pressure tubes, yes?

MR. EAGLES: This is the guide tool.

Q. - Oh there you go. We will get to the machine. The guide tool. Is that something that's new as well?

MR. EAGLES: Yes.

Q. - Has it been built?

MR. EAGLES: I'm not certain.

Q. - But it will be the same deal, NB Power will pay for it and AECL will --

MR. EAGLES: There is retooling being developed under the retube agreement that AECL has proprietary.

Q. - So AECL will own it again --

MR. EAGLES: Yes.

Q. - -- as the other machines? Okay. Now -- okay. Here is a machine. So this machine here is different than the machine used for withdrawing the pressure tubes?

MR. EAGLES: My understanding is that it's a separate machine from the pressure tube, although very similar.

Q. - Similar but separate?

MR. EAGLES: Yes.

Q. - Will only one be required or multiple machines as in the case of the pressure tubes?

MR. EAGLES: I would expect multiple.

Q. - Multiple. And again, NB Power will pay for it and AECL will own it?

MR. EAGLES: This would be AECL proprietary, yes.

Q. - Right. And it does the similar thing though, it pulls the Calandria tube out, tries out, and then slices it up and it falls down into a flask below?

MR. EAGLES: Correct.

Q. - Now what happens if -- in this case the pressure tube is,

you know, sort of not so heavily fixed within the Calandria tube, but with the Calandria tube which has been wedged into these struts, when you go to haul it out what if it sticks? What happens then?

MR. EAGLES: The process of removing the Calandria tube is for extraction from one end and jacking from the other.

Q. - So another machine or --

MR. EAGLES: The guide tool that you saw in the previous I guess segment of the video clip was a guide tool and also provided jacking for us.

Q. - So sort of you push from one end and pull it from the other?

MR. EAGLES: That's correct.

Q. - And if it sticks, like if it's not budging, sometimes, you know, that happens, can one of the workers just go out and, you know, give it a bang and loosen it up, or how do you -- what do you do?

MR. EAGLES: No. Tooling has been developed to overcome the forces of the interference fit that are there.

Q. - So separate tooling than this?

MR. EAGLES: The Calandria tube is -- I should mention as well is belled at both ends, so it is larger in diameter at the ends than it is in the centre and so it does not need to be jacked out over the entire length, just at the

interference fits.

Q. - Right. But still if it gets stuck and these machines pushing and pulling don't have enough mechanical oomph to unstick it, what do you do?

MR. EAGLES: Well we don't believe that that would be a concern but certainly would have to be addressed at that time, and I'm sure that AECL has put appropriate level of thought into that eventuality. It would be designed into the machinery.

Q. - Well, you know, even when you are trying to get a bolt and a nut apart, well designed, you know how they work, put your wrench on the bolt, it won't budge. Pull hard, it won't budge. You have got to find some other way to get that loosened up.

MR. EAGLES: Well I think Mr. Groom has indicated as well, that Calandria tubes have been removed and so what we have experienced -- or AECL has experience in the fact that they do come out.

Q. - That was a question about research reactor which is much smaller than CANDU-6. It may not be comparable, we will find out when we learn more about it perhaps from here. And they -- of course these are original machines as well as you have said, correct?

MR. EAGLES: Original and tested, yes.

Q. - All right. So hopefully it doesn't get stuck on one of these times. The machine pulls it through. Pushes from the other end. And like the pressure tube chops it up into the flask below. So that's -- here comes the Calandria tube out now. What -- so here the Calandria tube is sort of hanging out in space, the end of it?

MR. EAGLES: The guide tool you see is following the Calandria tube through so that it is supported at that end as well.

Q. - So is it supported by the guide tool?

MR. EAGLES: Yes.

Q. - And the only thing inside of the -- this support there is just the guide tool sitting through it -- running through it?

MR. EAGLES: Yes.

Q. - Yes. So this is just again the crushing procedure and getting chopped into smaller bits. Do you have any idea how much sort of fudge time AECL has built into their planning or should we ask them that in terms of dealing with breakdowns of the machinery and so on?

MR. EAGLES: I don't have specific knowledge of that.

Q. - So in terms of the -- what did you say the retubing procedure -- or the removal procedure was going to take -- no, what --

MR. EAGLES: The removal and reinstallation, the retube portion of the work would be 12 and a half months under the current schedule, which has been revised to 11 and a half months as a result of the additional tooling and modelling work that's undergoing under one of the change orders.

Q. - But the actual removal would be two months planned?

MR. EAGLES: The removal that I spoke of yesterday in the presentation was the removal of the fuel from the reactor and the draining of the heavy water.

Q. - But this part of removing the pressure tubes and the inserts and the Calandria tubes would --

MR. EAGLES: I didn't -- I don't have an exact time at -- here with me at this juncture, so I don't know.

Q. - I misunderstood from yesterday then. But you are going on faith that AECL has built an adequate time to allow for machinery breakdowns and snafus?

MR. EAGLES: We believe the schedule is achievable, yes.

Q. - Okay. So at this stage of the game once this has been done -- now I should ask, do you remove all 380 fuel assemblies before you start putting in new ones or do you remove one and put in a new one and --

MR. EAGLES: That has been I guess the model that was built into the original schedule. It's being looked at as to

whether or not there are faster ways of doing it by reinserting some of the Calandria tubes, but the current model was to remove all.

Q. - Okay. So the original schedule would be all the pressure tubes and Calandria tubes out and you would be left just with the Calandria vessel and the various other bits that are around it, but the fuel assemblies would all be gone?

MR. EAGLES: That's correct.

Q. - Yes. Then the last part here is putting a new Calandria tube into the vessel. And we are seeing either end of the reactor, the face here, the Calandria face, plugs being removed, I guess. And that's again the 20 foot distance between, as I understand. Now maybe you can just explain what's happening here?

MR. EAGLES: Just the guide tool is being inserted to guide the passage of the Calandria tube across the length of the reactor.

Q. - And it runs the entire length, the 20 feet or so?

MR. EAGLES: Correct.

Q. - And this could be two stories off the ground?

MR. EAGLES: This is on a platform that's very large that would not be unlike working in any floor within a power plant.

Q. - But still two stories in the air potentially, for the

upper row of fuel channels anyway. And now is this -- these are the -- well you explain what's going on here now? So what's about to happen?

MR. EAGLES: Sorry, I believe that this tool is locating the end of the Calandria tube at the tube sheet face.

Q. - And these are new tools as well?

MR. EAGLES: Specifically whether these tools are new I can't comment on. A number of the tools that have been developed for this project are new and a number of them are those that have been used in other works.

Q. - So as I understand, they are just trying to kind of line everything up, getting ready to insert the --

MR. EAGLES: Yes. Making sure that the Calandria tube is fit to the right length at that end of the tube sheet prior to inserting the Calandria tube insert and rolling the joint.

Q. - So this is very precise kind of work then in terms of lining everything up?

MR. EAGLES: Yes.

Q. - And so now we are seeing the inserts going into the Calandria tube, is that right?

MR. EAGLES: Yes, I think we just passed that. This is the leak tightness check.

Q. - Oh I see. This is some equipment to test the tightness

of the fit in the supports?

MR. EAGLES: Right.

Q. - And that -- is that equipment used from behind shielding or not?

MR. EAGLES: Well again, work at the reactor phase with fuel removed is substantially lower than what it is. And particularly now with all of the irradiated feeder tubes and pressure tubes and Calandria tubes removed, so radiation fields here would be substantially lower. A good portion of this work and whatever work absolutely has to happen at the reactor face is the only work that's done there by personnel. All other work that does not add value at the specific location is done in areas where the radiation fields are far less. That's the basis of the ALARA principle, as low as reasonably achievable.

Q. - If all goes well. Those -- that changes of course if things start to go poorly and you have got to take steps to remediate problems

MR. EAGLES: Only work that's absolutely necessary to be done in a radiation field is done there.

Q. - Correct. So the Calandria tube is inserted. The inserts were put in to try and expand it to wedge it into the supports. It's inspected, I guess with -- on the inside?

MR. EAGLES: Mmmm.

Q. - And then that's the end of that. But then the next procedure is to insert the pressure -- or the -- yes, pressure tubes --

MR. EAGLES: Pressure tubes and then fittings, yes.

Q. - -- inside the Calandria? Now would it follow the same kind of procedure we saw there?

MR. EAGLES: Very similar.

Q. - And the end fittings -- once the pressure tubes are in the end fittings, is that just a matter of applying the end fittings to the ends or is there -- is that a fairly complicated procedure?

MR. EAGLES: One end fitting is -- will be pre-welded to the pressure tube and the other end fitting would be welded after the pressure tube is installed in the reactor core.

Q. - Right. So you can weld that there. Okay. Well great. That makes the process much clearer than it was. Thank you for answering those questions.

MR. MACNUTT: Mr. Chairman, you were asking -- you were asking about the marking of the video. In my experience the usual approach is to take the video cassette itself and on the tag that's on the cassette itself you would enter your exhibit number and initials.

CHAIRMAN: Sounds like an appropriate way to go. Are you through with the --

MR. COON: The video, yes.

CHAIRMAN: Yes. Okay. Mr. Coon, would you or the technician -- or somebody take it out and give it to me and I will mark the beast.

MR. COON: Many buttons on that thing.

Q. - So then to get back to the earlier question that led into all of this, Mr. White, that has to do with the scope of the work here. The scope of the work then as we have seen it with regards to removal of the pressure tubes, remover -- removal of the Calandria inserts, removal of the Calandria tubes, reinsertion of the Calandria -- new Calandria tubes, reinsertion of the inserts and the new end fittings is fundamentally different than that performed during the initial construction of Point Lepreau?

MR. WHITE: The Calandria tubes, as we already said, were installed by the manufacturer in the assembly shop. The pressure tubes were installed on site. And so the installation of pressure tubes would be somewhat similar to what we just saw in the video.

Q. - So but my question is, do you agree then, the scope with respect to this work is very different than the scope of the work that was done on site in building Point Lepreau?

MR. WHITE: The scope has additional elements, as you have

already pointed out. That the Calandria tubes were not installed during the original construction on site so they are different, yes. And that the work is going on in a radiation environment. And that is different, yes.

Q. - So while you say this is a fraction of the work that was done, a number of elements of it are substantively different than the work that was done in building Point Lepreau. Is that correct?

MR. WHITE: This is a fraction of the work that was done in constructing the complete site in Point Lepreau, that is correct. But there are elements of this work that are different than the original construction. And that is also correct.

Q. - Thank you, Mr. White.

MR. EAGLES: If I may comment, Mr. Coon, the installation of Calandria tubes at the Quinshan reactor in China, AECL has informed us that the installation of those Calandria tubes took place in a period of 100 hours.

Q. - Was that done in a radiation field?

MR. EAGLES: No radiation field there. And this was given in the interrogatory response to NBPCraik-3.

MR. THOMPSON: Could you repeat that?

Q. - The response was which now?

MR. EAGLES: NBPCraik-3.

Q. - And that was, just be clear, a reactor under construction that hadn't been operating yet?

MR. EAGLES: That's correct.

Q. - So no radiation fields –

MR. EAGLES: That's correct, yes.

Q. - -- and no worn out parts? Okay. So I guess the question, Mr. White, is given that this -- that this contains elements of work that have never been done before at Point Lepreau, as you do on page 9, I guess, I'm wondering how you can say that the scope of what needs to be done here is well understood if you haven't done some of this work before.

And Mr. Eagles has pointed out he doesn't know what would happen in the event of something getting -- of one of the pipes getting stuck during withdrawal or what would happen if a Calandria tube fell into the reactor? How can you say the scope is well understood? It seems to me the scope at this point is not well defined at all. Isn't that correct?

MR. WHITE: This is work that has been done by AECL in its various reactor jobs across the world. And so the work is known to them and known how to do it. They are continuing the evolution of development of faster ways to do this work, and vis-a-vis the tooling and the time we have

invested in modelling and whatever to do this work here. But AECL has done this type of work, although all of it has not been done at Lepreau.

Q. - Well, Mr. White, you can't have it both ways. We have – up until now you were telling us the work in terms of removing Calandria tubes on a production basis -- Mr. Groom said he believes that had been done perhaps at a Chalk River research reactor. And then reference is made to a response to an interrogatory where it was said that installation of Calandria tubes was maybe done in China on site. Are there other instances, or are those the two you are referring to when you say that AECL has done these kinds of things all over?

MR. WHITE: Well let's separate. We said that this type of work has been done, in terms of the volume of removing Calandria tubes on a wholesale reactor basis, that has not been done in a commercial reactor.

Q. - Okay. And so that therefore means, wouldn't it, that it's hard to define the scope of this work at this point, given that that has not been done before in a commercial reactor?

MR. WHITE: You can build up all the elements from having done the individual elements and they add up to what you believe is the appropriate time frames to do this actual

work in a production basis.

Q. - But without experience you don't have an idea really of what sorts of things might go wrong and would change the scope of this work, isn't that correct?

MR. EAGLES: In the course of work at Pickering 4, we have been informed that the schedule to complete the fuel channel assembly, which did not in this case include the Calandria tube, was about nine and one-half months. And that that work, of course, was done, you know, some eight years or more ago. And in that ensuing eight years a substantial amount of development work has been done by AECL through their work with Bruce and through the Phase 1 work that we have in developing tools and procedures. We believe that the incremental time certainly is within the schedule that -- that we have been provided by AECL. We are -- we are quite confident in this process.

Q. - Can you clarify that, Mr. Eagles. You said it took nine and a half months to remove and replace just the pressure tubes at Pickering?

MR. EAGLES: Fuel channels in Pickering 4, yes.

Q. - So the pressure tubes, but not the Calandria tubes?

MR. EAGLES: That's correct.

Q. - And not the feeder pipe attachments?

MR. EAGLES: The specific details of the feeder I'm not

aware of. I don't believe that as much of the feeder was removed there.

Q. - Your 12 month estimate includes feeder pipe replacement?

MR. EAGLES: It does, yes.

Q. - Yes. So this was just pressure tubes in nine and a half months?

MR. EAGLES: Yes. And we believe that the feeder removal will allow better access at the face of the reactor. And will in fact potentially improve the replacement time.

Q. - And this was done with different equipment. Because as you pointed out, a number of these machines are brand new and haven't been used operationally?

MR. EAGLES: It's our understanding that about 80 percent of the equipment is that or derivations of that which have been used before, and about 20 percent is new.

Q. - When you say derivations, just to be clear you mean equipment that was modified or rebuilt?

MR. EAGLES: Improved, you know, based on experience, operating experience.

Q. - Okay. Thank you. Sticking with the scope of the work, if we could go to A-6, back to the minutes. And that's CCNB-102 again. And specifically I'm looking for the meeting date April 27th 2000. So that is April 27th 2000, minutes of the Board of NB Power.

Mr. White, I guess you were there, according to the minutes. So I will direct this question at Mr. White once everyone has got to the spot.

So it is 12, page 12 in those minutes.

MR. WHITE: Sorry. I'm only up to page 8 on those. April 27th 2000?

Q. - April 27th 2000, yes, at page 12, marked page 12. It is the second page of the minutes in that meeting.

MR. WHITE: Okay.

Q. - Now about midway down in the minutes here, Mr. Hankinson, who was CEO at the time, noted that the steam generator -- this is in the context or refurbishment of course.

Mr. Hankinson noted that the steam generator life will be an issue for NB Power as to whether or not to replaced these during the refurbishment or to allow the plant to operate with the present steam generators for a number of years.

When they talk about steam generators, are these the boilers we are talking about?

MR. WHITE: That is correct.

Q. - I'm thinking back to the presentation, the graphics you gave yesterday where we saw these two boilers sort of up above the Calandria in the graphic anyway?

MR. WHITE: That is correct.

Q. - Yes. Okay. Now what was the decision at this point with regards to the steam generators or boilers? Would they be part of this refurbishment or not, replacement of them?

MR. WHITE: This issue has been -- was raised by Hagler Boyer in their work, that the steam generators would need to be properly assessed in terms of whether they would need to be replaced during the extended life of the station or not.

And so the minutes are reflecting the issue that a good ascertation of the life of the steam generators needs to be undertaken and completed to assure ourselves as to whether we either need to address replacing them or alternately whether in fact they would -- are projected to be healthy for the life of the station on an extended basis.

Q. - And the results of that assessment were what, Mr. White?

MR. WHITE: Mr. Groom referred to that yesterday in that the steam generators were assessed by three companies, their manufacturer Babcock, AECL and a German company, Siemens.

And they determined the steam generators would be healthy under continuing normal maintenance programs and that they believed that they would last for the life of the extended station.

Q. - If they don't, and as it suggests here in the Board

minutes that the plant might operate with the present steam generators for a number of years but less than the 25 projected life of a refurbished Lepreau, have you done any -- had any rough estimates done of what it would cost to replace those boilers or steam generators?

MR. WHITE: The rough estimates are around 120, $125 million to replace those.

Q. - And that would be a cost to replace while Lepreau is down during refurbishment? Or is that -- would it be a similar cost if the plant had been up and running for a few years and then you had to replace them?

MR. WHITE: As you referred to this morning, if we had to take an additional outage to replace them, then you would have the replacement energy issues to deal with.

Q. - Right. But the actual -- technically there is no advantage to replacing them while the major refurbishment is occurring versus replacing them if they break down 10 years forward?

MR. WHITE: Technically there is no difference. But from an economic case point of view it was quite a difference. Because if they were replaced during this outage then you don't have to take an extended outage sometime in the future to replace them.

And therefore you have replacement energy costs that

would have to be put into the business case for that.

Q. - Thank you. How much time would it add to the project to also replace the boilers -- or steam generators, I'm sorry? It is the same thing, I guess.

MR. WHITE: We didn't specifically analyze that because we went through the assessment process of looking at the health of the steam generators and determined that they would last through the life extension period.

However -- and it is not exactly comparable. I mean, there is utilities in the U.S. that have replaced boilers. And some of them are as short as four months, three or four months.

So in theory they could be done during the refurbishment outage if we wanted to do them there.

Q. - Where if any CANDU reactors have had to replace their boilers or steam generators thus far?

MR. GROOM: I would point out that the steam generators at Point Lepreau were replaced. And they were replaced as a part of construction.

The original steam generators supplied by the vendor during construction were found to be damaged. And they were completely replaced at Point Lepreau as part of the construction operations.

So there is an example there. There have been other

CANDU reactors who have had similar problems during construction.

Q. - I'm just wondering if they have worn out anywhere in a CANDU reactor?

MR. WHITE: Just to be accurate on that, the tubing in the steam generators was replaced during the original construction, not the actual vessel itself.

Q. - Yes. Thank you.

MR. GROOM: The other point is that the material that has been used in the steam generators at Point Lepreau is different from some of the -- it's an alloy, inconel-800.

And it has been used in steam generators in Germany. It has been demonstrating very good performance. Usually the challenge with steam generators has been with the performance of the tubing.

And as Mr. White pointed out, it was the tubing that was the problem in the early days. The replacement material with Lepreau has been performing very well.

And as he pointed out, the assessment that was done by this joint team, which included 100 percent inspection data from the boilers, concluded that they are in very good shape, current condition.

Q. - Have any CANDU reactors had to replace -- aging CANDU reactors -- I don't mean the up-front, but aging CANDU

reactors, have they had to replace boilers or steam generators?

MR. GROOM: I'm not aware of any CANDU reactors that have had to change or have changed steam generators.

Q. - Okay. Thank you.

MR. COON: Mr. Chairman, I'm wondering if we want to take a break for lunch now. Because I'm going to start on a different course. Or I can keep going. At your pleasure.

CHAIRMAN: Well, I think we will take our break for lunch now. And I'm going to mark the video which -- I'm going to mark it as an applicant exhibit in that you folks showed it and that sort of thing. And it will be A-19.

Okay. Is an hour and 15 minutes sufficient time for everybody to get lunch and get back? Good. We will reconvene at 1:15 then.

(Recess - 12:00 p.m. - 1:15 p.m.)

CHAIRMAN: Just before I ask the intervenors and the applicant if they have anything, the panel over lunch had been chatting about cross-examination this morning, et cetera.

And we decided that we would like to see if we can get NB Power to file something. And Mr. Sollows will give you the details on it.

MR. SOLLOWS: Yes. It has become clear that the project

schedule is a critical component of this overall proposal. And what we are interested in is the documentation that might have been prepared for your critical path analysis or your pert analysis that would give us the best times, the worst times, the median times or however you have done the analysis.

We don't need all of the detail. But if you could give -- you know, file something that would give us some indication of the critical path and the alternative paths as certain events occur.

Is it possible to provide that? Not today obviously.

MR. WHITE: We will access that information.

CHAIRMAN: Anybody else have any preliminary matters?

MR. HASHEY: Yes, Mr. Chairman. There were some undertakings requested this morning.

CHAIRMAN: Yes.

MR. HASHEY: Over lunch hour the panel has done the best they could to get as much of that information so that it would be available to Mr. Coon and to the Board.

And possibly I could request the panel members who have answers to provide them at this time, if that would be what you would wish to have done.

CHAIRMAN: Yes. All right. I will get to you, Mr. Hyslop, in a minute. Go ahead, lady or gentlemen, whomever it may

be.

MR. HASHEY: Maybe Ms. McKibbon could give the first -- she has the first bit of information.

MS. MCKIBBON: I have been asked to provide an escalated figure for the $300 million of replacement power. I would like to point out that Mr. Marshall's evidence does contain estimates of replacement power that have been factored into the economic analysis.

However the 300 million escalated to 2007 dollars would be approximately $334 million.

CHAIRMAN: Thank you.

MR. HASHEY: Thank you, Ms. McKibbon.

Mr. Groom, I believe you might have --

MR. GROOM: Yes.

MR. HASHEY: -- one, and might indicate the ones that require a little more time this afternoon?

MR. GROOM: Yes. That is right. There were two questions that I was asked. One was about the Calandria tube history. And we expect that we will have that later on this afternoon, which I will provide. I don't have it yet. The other is related to an issue on the decommissioning plan and the schedule.

And Mr. Coon, just to make sure I did understand the question correctly, I understood that you were asking is

when are the decommissioning scheduled, are the pressure tube and Calandria tube removal activities planned?

And an additional question was what percent of the decommissioning cost is assigned to the Calandria tube pressure tube removal in that decommissioning plan, is that correct?

MR. COON: Correct.

MR. GROOM: All right. In regards to the information you are looking for, I think you will find both responses are contained in PNB-57. And in that are contained the decommissioning plan and the decommissioning cost estimate.

Q. - I'm sorry, Mr. Groom. Could you give an exhibit number on that to help us find it?

MR. GROOM: PNB-57. Oh, is it the binder? I'm sorry. It is binder A-9.

MR. COON: A-9. Thank you.

MR. HASHEY: No. It can't be A-9.

MR. GROOM: Mine shows it as A-9, volume 5 of 7. And there is a tab in there of PNB-57. It is the second tab. And in the decommissioning plan you will find on figure 10 a schedule.

CHAIRMAN: What page is that on, Mr. Groom?

MR. GROOM: It is in appendix on page 13 of 18. So that

will be -- and as I had said this morning, it is scheduled between years 2041 and 2043 on that schedule which is between years 34 and 36 on the material that is provided in the evidence.

Q. - Sorry. Are we looking at section 3, page 13 of 18?

MR. GROOM: Looking at -- I will try it again -- PNB-57. The document is entitled "The Preliminary Decommissioning Plan for Point Lepreau." And in that there is an appendix to the document.

Q. - Just one appendix?

MR. GROOM: Just one appendix. And it is on page 13 of 18. It has more than one appendix. It is the first appendix, sorry. And you will find in there a decommissioning schedule.

Q. - Sorry. I'm still not -- is it appendix D we are talking about?

MR. GROOM: Unfortunately the appendixes aren't explicitly numbered. It is just called the appendix. The report is a report by a company called TLG Services. Have you got the right report?

Q. - Okay. I have got it.

MR. GROOM: Now you will note in this that the way the information is laid out it is identified as part of the task for what is called PHT removal. And part of the PHT

removal involves disassembly of the fuel channel assemblies.

The other is that in this appendix there is also the information on the costs detailed. And the costs are not broken down in the way you asked them. But the information for the costs over that time frame as shown by the evidence amounts to about $75 million.

Q. - So in figure 10 I'm looking at, "PHT Removal" is the appropriate heading? And then under that --

MR. GROOM: It is contained in the PHT Removal or PHT Planning. It is in the Stage 3 Costs for Planning and for PHT Removal.

Q. - Yes, I see.

MR. GROOM: And that represents about 16 percent of the cost.

Q. - So I see something called "Calandria Segmentation, Preparation" and "Calandria Segmentation"?

MR. GROOM: That would occur after the Calandria tubes and pressure tubes had been removed. So it is part of the -- it is part of the total exercise to withdraw and remove the Calandria vessel itself.

I want to point out that the way that this decommissioning plan would propose to do the work is very, very different in terms of the total scope. The process,

as I mentioned earlier this morning, for removal of pressure tubes and Calandria tubes would be substantively the same.

But the work as laid out in this decommissioning plan is not the same work as is proposed in the retube work. Because in the course of retube we want to put new fuel channels back in.

Q. - But the removal process would be the same for the Calandria and pressure tubes, as you said?

MR. GROOM: It would be similar.

Q. - Similar? And is there a particular line on this table that refers to the time period over which the removals of the tubes would occur?

MR. GROOM: Yes.

Q. - I mean, the stage 3 has got a lot of bits to it?

MR. GROOM: And that time frame, as I mentioned just a minute ago verbally to you, between 2041 and 2043.

Q. - So over a two-year period?

MR. GROOM: Yes.

Q. - So you would spend two years --

MR. GROOM: It would be --

Q. - -- to remove the pressure tubes and Calandria tubes?

MR. GROOM: Well, it will be one of the steps in the total amount of work that is identified on that line.

Q. - Okay. So we can't determine from this then, is that correct, how many -- how much time actually would be involved in the fuel channel removal process?

MR. GROOM: That level of detail is not here.

Q. - Is not here? Okay. Thank you.

MR. COON: All right.

MR. GROOM: I think that answers the questions.

CHAIRMAN: Those are all the undertakings, Mr. Hashey?

MR. HASHEY: At this moment. One for later.

CHAIRMAN: Mr. Hyslop?

MR. HYSLOP: Yes, Mr. Chairman. There was a question posed by Mr. Sollows to Mr White. And Mr. White's microphone wasn't on. I assume he answered that they were going to file some information. I didn't hear the answer.

MR. WHITE: Yes. The answer is that we will file something on the CPM schedule.

MR. HYSLOP: And the second issue we had very briefly, Mr. Chairman, there was an indication yesterday from the Chair directed to Mr. Hashey concerning filing of updated or providing of updated financial information and business plans.

And I was just wondering if there is any idea of what the timing on that might be?

MR. HASHEY: I know it is under way, put it that way. I

will consult with Mr. Little. I'm not sure that we have any firm fixed time at the moment. We are aiming at sometime Thursday.

MR. HYSLOP: Thank you very much.

MR. HASHEY: Safer course probably to say for Monday for sure.

MR. HYSLOP: Thank you, Mr. Chairman.

CHAIRMAN: Okay, Mr. Hyslop. Any other parties have anything they want to bring up? Go ahead, Mr. Coon.

MR. COON: Thank you, Mr. Chairman.

Q. - Before we broke for lunch, Mr. White, you had mentioned the $7 million cost to build the first machine to withdraw the pressure tubes.

I was wondering if you could undertake to provide us with a total on the costs of hardware to date, hardware constructed or purchased to date for the Refurbishment Project?

MR. WHITE: We don't have those as broken down costs. That is part of the total retubing package. And the piece to develop the initial tooling work and to develop initial computer programs and graphics and the type of things you saw this morning was an advancement of $7 million towards that piece of work.

That is part of the total fixed price scope of AECL.

And we don't have a breakdown of those.

Q. - So you are saying you don't have any way of telling us how much money has been spent to date on hardware?

MR. WHITE: I can tell you how much money has been spent to date. How much money has been spent on hardware, no, I don't know.

Q. - Okay. Thank you. Now let's go to appendix A-6, Board minutes. This is going to be an easy one. The last -- the meetings -- the minutes for the very most recent meeting, December the 18th 2001 --

MR. WHITE: Sorry. The reference book again?

Q. - I'm sorry. It is exhibit A-6. And of course this is CCNB-102 again and it is the minutes from the meeting of December the 18th which is behind the very last blue divider.

MR. WHITE: What year?

Q. - December 18th 2001. And in those minutes is a page entitled "NB Power Point Lepreau refurbishment 24 high risks". And it follows -- the initial pages in these minutes are numbered and it follows the numbered pages which go to 13. The second page past number 13.

Now under NB Power Point Lepreau refurbishment 24 high risks is divided into licensing, technical project management and contractor. And I would like to begin with

the section concerning technical high risks.

The first high risk identified here is the moderator recovery system is required because seamless Calandria tubes cannot be qualified or licensed. Is a moderator recovery system going to be required for the refurbishment?

MR. WHITE: It is not required if we have seamless Calandria tubes. The idea behind this list that you have is from managing a risk point of view and we want to identify those that need particular attention throughout the process of doing preparations and engineering for retubing. And we recognize that there is an issue with the moderator recovery system and that it could be solved in a number of ways. And the most practical way of solving it was with seamless Calandria tubes. And therefore we have invested in doing that, as it was discussed earlier.

Q. - Is there any question that the seamless Calandria tubes will not be qualified or licenced at this point?

MR. WHITE: We believe technically that we have advanced the work and that there is ample time to do it and that the -- we don't see any reason why it can't be done. But we always want to maintain an eye on it.

Q. - Whose decision will that be as to whether the seamless

Calandria tubes can be qualified?

MR. WHITE: It is AECL's responsibility to execute the work.

Q. - Would the Canadian Nuclear Safety Commission have anything to say about whether you could be licenced with seamless Calandria tubes?

MR. WHITE: Ultimately they will have to accept it, yes.

Q. - And the moderator recovery system in lieu of seamless Calandria tubes, is that -- what sort of costs would you be looking at if you had to install that?

MR. WHITE: Again this deals with a generic issue in the industry and various ways to deal with it and so the solutions to all of that aren't worked out in the industry. But from an indicative point of view, we are looking at a range of probably 10 to $15 million or so.

Q. - And would that -- would that throw your critical path off by days, weeks or months?

MR. WHITE: We don't see that throwing the critical path off.

Q. - Thank you. With respect to the main turbine inspection, is that something that can only be done if you go ahead with the project or has it been done?

MR. WHITE: We are doing that as we speak.

Q. - So it has not been completed as yet and therefore you can't conclude anything at this point. Is that correct?

MR. WHITE: It is part of the current outage in Lepreau. And it was actually taking place late last week and this week.

Q. - What are the implications of cracked spindles in the main turbine?

MR. WHITE: Well if you had a gross crack you might have to replace the spindle. If you had a minor crack you may be able to disposition it by grinding or other -- or monitoring or other alternatives.

Q. - Why would this be an issue for the refurbishment?

MR. WHITE: We want to ensure the healthiness of those spindles and if we had to replace them of course that would be an additional cost item.

Q. - Would that be done anyways if you discover these or only in the case of refurbishment?

MR. WHITE: Again, it depends on the issue that was found and the severity of that. If it was significant we would have to do it in the near term. If it wasn't significant we would have a monitor and maintenance program on it.

Q. - Thank you. Is condenser inspection proceeding now during the current shutdown as well?

MR. WHITE: Yes. It is part of the current outage that is going on in Lepreau.

Q. - Is it premature to draw any conclusions on the

condensers?

MR. WHITE: I don't have the results of that because I believe the work is not completed yet.

Q. - The next point on inherent component flaws in the existing generator frame core -- well maybe you can explain this and then tell me what the significance of it is?

MR. WHITE: Well we need to do two pieces of work in the generator. The rotating element is called the router. And the stationary element with windings in it is called the stator. And both of those we need to take the electrical copper coils out and replace them because the insulation between those coils deteriorates over time and won't go through an extended life of operation. So we need to rewind both of those components.

And one of the potential you usually have is the slots on the stator that the coils go into. They may actually have mechanical issues with them. And so we have looked at various alternatives as to whether we actually do a rewind or in fact do we replace the stator itself or do we in fact replace the whole generator and what is more cost effective. So we have looked at three of those alternatives. And that is part of the provisional pricing that is in our cost estimates.

Q. - The current proposal calls for the rewind, is that correct?

MR. WHITE: We would believe that the rewind is probably the most economic. But that won't necessarily be concluded until we create firm tenders around that.

Q. - Would a decision to replace it with new components add days, weeks or months to your critical path?

MR. WHITE: I don't see that that would change the critical path.

Q. - And the additional costs of going for replacement instead of rewind would be approximately what?

MR. WHITE: Mr. Ealges can give you an update on that.

MR. EAGLES: As I have mentioned in my presentation yesterday we had received some budgetary pricing from some vendors. And we had asked for pricing on both rewind and replacement options to evaluate which would be most effective. And at this point we have pricing from one vendor on rewind and pricing from another vendor on replacement which are about equal at the levels that I talked about yesterday. So we believe that if as we go forward in our discussions with the vendor, after approval of the project, we can conclude our negotiations with one of those vendors, that perhaps replacement of the generator might eliminate any future risk in this area.

We believe that might be prudent.

Q. - The next high risk that is identified is reactor assembly component inspection. Explain that to us, please?

MR. WHITE: This is the first opportunity to actually look inside the reactor vessel as you remove the tubes. We have done remote looking of that in the past. And there are some weld components in the reactor that we have analyzed to ensure that their ductility doesn't change over a life time. And that that is suitable for ongoing operation we would want to visually inspect those welds. We would also visually inspect other attachments that are welded on onto the internal walls of the Calandria vessel while we have the pressure tubes and Calandria tubes removed. It is a unique opportunity to do an inspection that you only get to do under those circumstances.

Q. - So you would only know if this would affect the scope of the work once the tubes were out of the Calandria vessel, you could have a look?

MR. WHITE: Our belief is that this is a very low risk activity from all the analysis that has been done. But we still think it is prudent to undertake it.

Q. - If there was a problem with the weld components inside the reactor vessel that you discovered once you had removed all the tubes that this project went ahead, would

it require new tooling to solve that problem, or is it solvable, or what are your thoughts on that?

MR. WHITE: We discussed that in context particularly as you asked. And we believe that issues that would be found in there, although they might be challenging, are solvable, yes.

Q. - Would they be solvable through new tooling or solvable through something you have got down in the shed there?

MR. WHITE: We may need to have new tooling or new methods depending on what the issue is and where it is. The Calandria vessel inside is a -- the vessel itself is a fairly simple vessel with attachments on the walls and things. There are lots of components that go through the vessel that can be removed externally. And so we are really talking about kind of fixed attachment areas and fixed welds and those kinds of things that we were particularly interested in and just doing a review in this unique opportunity.

Q. - Thank you. The next high risk you have identified is identified as the environmental qualification of all the PVC cables. What is the risk there?

MR. WHITE: Polyvinyl chloride insulated cables, the cable jacket is made out of PVC's when exposed to radiation environments can deteriorate. We have carried out 30 year

studies on that them and we are in the process of completing 50 year studies on them. Some of the cabling that I think Mr. Groom may have referred to in his presentation that is necessary under accident conditions we would replace during this -- this outage that's coming up. The other PVC cable we determined is acceptable for extended life.

Q. - Now what is the high risk in this case though, that -- that would -- would occur to you as a -- as a concern?

MR. WHITE: I will let Mr. Groom give you some more details on that.

Q. - Okay, Mr. Groom?

MR. GROOM: The risk we think would be to certain of the monitoring cables, which would then need to be essentially replaced. And, indeed, some of those are included in the scope of work already.

Q. - But why is that a high risk? And isn't it just a matter of replacing a couple of cables if that's the problem?

MR. GROOM: Well that's -- that's why we don't -- we think that the testing program we put in place, which is ongoing as Rod pointed out, will be successful in demonstrating 50 year capability of the cable. But until those tests are done, we don't know which others may need to be included or whether the scope might increase. So at this juncture

we have taken a conservative estimate for the requirements. And the cables -- the cable testing program that we have conducted so far has been very positive and indicating that there should be adequate margins in the cables to give us the service we need.

Q. - Okay. The next issue under technical identified as high risk is the emergent work resulting from inspections during outage. Mr. Groom or Mr. White, do you want to explain that, why that's a high risk?

MR. WHITE: We always recognize that going into a maintenance outage and doing inspections can, in fact, uncover things that need to be addressed. As an example we are going to go into the seawater cooling circuits for the plant equipment. And we are going to go into conventional cooling circuits for plant equipment, looking at valving and heat exchanger, a number of other items. We may find issues with piping that needs some repair, those kinds of things as we do that.

Q. - And then the final point under technical high risks would be pressure tube and feeder remaining life.

MR. WHITE: Yes. Mr. Groom spoke at some length to those. And our predicted life periods for those with the strong maintenance programs we have going on. As an example, we have the feeder cracking issue. We have just inspected

all of those feeders during the current outage and have found no additional cracking that needs to be addressed, so that's a positive. We still in this outage will be doing the feeder thinning measurements that we do in each outage, so we are monitoring that program. And Mr. Groom spoke to the fact that we anticipate having to replace two feeders in 2003 and 2005. And each of those, because of access requirements, will require us changing out some other one.

And the pressure tube program we are currently in the process of SLARing 68 fuel channels to again put the springs in the right positions. So those are ongoing type programs, and we continue to monitor those and each year update from any inspection work our predictions that we gave you yesterday on lifecycles on these components.

Q. - But it's identified as a risk because of the possible requirement to shut down the reactor for a period of time in its last remaining years of life, is that why it's identified as a high risk?

MR. WHITE: It's identified as a high risk in that if it occurred prior to the outage, then we wouldn't be prepared to undertake an outage in a good planned state. And if they go past the outage date as we are currently predicting, then of course we have got a well planned

outage to move into.

Q. - Thank you. So in listening to the explanation for these high technical risks to the refurbishment project, Mr. White, it's clear as Mr. Groom said, that the scope may indeed increase based on these various inspections that are going on now. Inspections that would happen if the -- if the project goes ahead and you get a chance to peer inside the reactor, that that could result in fact in a -- in an increase in the scope of the project. Is that correct?

MR. WHITE: That's correct. And that's why we identified the risk. And that's why we have a contingency on this project.

Q. - So the scope really is not completely defined as yet for this project then?

MR. WHITE: The scope is defined in terms of the assessment and the work that we believe needs to be done. But we certainly recognize that there are risks that need to be managed, and we should have some contingent funds available in case some of those risks surface.

Q. - Thank you, Mr. White. Don't put that exhibit away quite yet. But I want to refer you to exhibit A-1 on page 9 of your evidence, Mr. White.

And on page 9 you say the scope of what needs to be

done has been confirmed by the nuclear regulator. Is that correct?

MR. WHITE: Yes, we have done that in the licencing framework document.

Q. - Have any approvals been received from the nuclear regulator?

MR. WHITE: Final approvals would be received ultimately from the Commission. We have what we classed as a comfort letter from the regulatory staff that identifies their review over the last two years of working with us, the items that we believe are issues in the regulatory ball park, regulatory arena. And that we have reasonable understanding between both the parties as to what the work would need to be done, and therefore we were able to cost it and schedule it.

Q. - Well if we go to the Appendix A-1 of your evidence there in the nuclear regulator letter, the front -- first page of that to you, Mr. White, the subject says, CNSC staff position on activities related to the refurbishment of Point Lepreau. And then in the bottom paragraph it says, NB Power should be aware of the limitations of CNSC staff authority in this regard. For example, CNSC staff cannot bind the Commission on the decisions it makes today or in the future. Nor can present staff bind tomorrow's staff

on recommendations it may make to the Commission. CNSC staff is also limited in what it can say at this time by the relative immaturity of the project assessment work and CNSC staff review.

So my question is, how can you conclude that the scope of what needs to be done has been confirmed by the nuclear regulator?

MR. WHITE: We have carried out a rigorous process with staff. And this is the normal process of dealing with the regulator in terms of identifying the areas that we think need to be addressed. And from their point of view, them reviewing and assessing that and providing feedback to us and that we recognized early on with the staff, and they communicated to us quite clearly, that at the end of the day we are talking about a proposed project at this point in time with them.

And that we haven't brought formal submissions in front of their Commission relative to refurbishment because obviously we haven't got approvals on this project at this point in time. And so we work through a due diligence process of identifying the regulatory requirements, understanding what requirements exist in the industry today, reviewing our work against those things. And putting forward a framework and getting from them --

and we had requested to get from them essentially a level of comfort. Because therefore we need to identify the risk that the comfort on the regulatory scene poses to us and what the costs may be. And so although these aren't complete until they go to their Commission and get final review, it is the normal process of dealing with staff. And we can take a fairly high level of comfort that they are -- they, being reasonably comfortable with the approaches and the timing, the effort and the areas that we are working on, is a reasonable representation of what staff would accept and therefore recommend to their Commission for acceptance.

Q. - So, Mr. White, when you refer to the nuclear regulator, you are really talking about the regulator staff. Is that the more precise way to put it?

MR. WHITE: The Nuclear Safety Commission staff, yes.

Q. - The Safety Commission staff. But even so, the Nuclear Safety Commission staff in the front page of this letter -- the first page of this letter says that it is limited in what it can say at this time with respect to this project. So I still -- I'm asking you how you can conclude that even from the staff of the -- of the Safety Commission's perspective that the scope of the project has been confirmed?

MR. WHITE: They have an obligation to be precise in saying that they cannot commit their Commission and they have done that.

Q. - But they have also said that CNSC staff itself is limited in what it can say because of the relative immaturity of the project assessment work, some of which you were just describing in regard to the high risk technical issues for refurbishment. So wouldn't you agree that the CNS -- CNSC staff here are saying that they as yet haven't got enough information to confirm the scope of the project?

MR. WHITE: I think the answer to that is yes, that there is a lot of work to be done in the four years of engineering and we would have continuous involvement with the staff over that period of time.

The effort here was to determine what is the risk and therefore what is the price and schedule implications to proceeding with this schedule and we believe that we have quantified them within a reasonable certainty.

Q. - Thank you. And am I right in concluding from this that the Canadian Nuclear Safety Commission itself, that is the Commissioners, could make regulatory decisions that would be different than what their staff are telling you in one case and secondly, decisions that would change the scope of the proposed project?

MR. WHITE: Yes, they are independent and they can make those determinations, but again, they rely heavily on the work of their staff to advise them.

Q. - Now if we could take a look at CCNB or I don't know, number 1, it is not a--

CHAIRMAN: Marked 1 for identification or ident. 1.

Q. - What should I call it, Mr. Chairman?

CHAIRMAN: Ident 1.

Q. - Ident. 1, that is a new one. Now, Mr. White, this refers to a meeting that you attended of the Canadian Nuclear Safety Commission.

MR. WHITE: Yes. Go ahead.

Q. - This refers to a meeting that you attended of the Canadian Nuclear Safety Commission a week ago, is that correct?

MR. WHITE: That is correct.

Q. - And at that meeting there was a distinct difference of opinion between the Commissioners of the nuclear regulator and their staff vis-a-vis the need for an environmental assessment of the refurbishment project, is that correct?

MR. WHITE: I wouldn't classify it as that. I would say that the nuclear commission thoroughly explored the key issues as to what is the requirement for an EIA in that meeting. They asked the questions to make sure that the

area was properly investigated and provided feedback from both ourselves and their staff relative to the work done to date.

Q. - I understand from ident. 1 that commissioners here are disagreeing with their employees on the scope of the proposed environmental impact assessment for the new on-site waste storage facilities that would be required if the proposed project were to go ahead.

MR. WHITE: One might get that impression from reading the newspaper article, but that's not my impression from sitting in the meeting. My impression from sitting in the meeting is that the Commissioners have a responsibility to thoroughly investigate the recommendation as brought before them, that ensuring that the public record is complete and clear on that before they make the decision -- their decision, so that the basis of their decision exists on the public record.

Q. - Would you agree that there was a difference of opinion over the scope on a consideration for the proposed environmental impact assessment between some of the commissioners and their staff?

MR. WHITE: The Commission explored why the scope should not be different than that that was placed in front of them for recommendation.

Q. - This ident. 1 also quotes you, and we will see if this is accurate, that says that the proposed 18 month refurbishment is essentially a planned maintenance outage. Were you accurately quoted there?

MR. WHITE: That's correct.

Q. - But a little earlier today you told us that in fact Point Lepreau was going to be at the end of its life and couldn't be -- this couldn't be considered as a planned maintenance outage when thinking about incorporating the cost of replacement power.

MR. WHITE: We have an operating licence for this facility and if the decision -- recommendation of this panel and the ultimate approval is given to go ahead with this refurbishment, then we will take an outage within that operating licence that is essentially a maintenance outage to do refurbishment work and normal maintenance repairs.

Q. - Well, Mr. White, with all due respect, you can't have it both ways. It's either a planned maintenance outage or the plant has reached the end of its life. Which is it?

MR. WHITE: In regulatory terms for the CNSC this is a maintenance outage within our licence. In terms of this hearing this decides whether the plant will be refurbished by NB Power or not on a recommendation to our Board.

Q. - So what you are telling me is that the CNSC will consider

this as a planned maintenance outage while from NB Power's perspective you see it as the end of the operating life for Point Lepreau.

MR. WHITE: We need a decision relative to the end of the operating life. If the decision is that this plant should continue then in the regulatory licence requirements we have posed this as a planned maintenance outage.

Q. - With respect to the decision that the Canadian Nuclear Safety Commission commissioners make about the appropriate scope of the proposed refurbishment project, you really have no idea what the Commissioners might decide, is that correct?

MR. WHITE: I think we don't have the results, but having had 20 years of working with the regulator on normal operating licencing requirements we have a pretty good perspective on what is acceptable and not acceptable in regulatory terms, and when we get agreements with staff at certain levels, well those things in fact stand when we are in front of their Commission.

Q. - But you would agree there is no particular requirement for Commissioners to agree with their staff.

MR. WHITE: That's correct.

Q. - They may disagree with their staff?

MR. WHITE: That's correct.

Q. - Now I would like to look at how the regulator might in fact change the scope of the project, and to do that, for those of you who have closed your book, exhibit A-6 -- back to exhibit A-6, CCNB-102, the meeting of December 18th 2001.

CHAIRMAN: Would you repeat that, Mr. Coon, the reference, please?

MR. COON: Yes. It's exhibit A-6, CCNB-102, and the minutes of the December 18th 2001, meeting.

CHAIRMAN: The meeting that we were looking at before?

MR. COON: Yes, the same one before.

CHAIRMAN: Yes. Thank you.

CHAIRMAN: NB Power Point Lepreau refurbishment 24 high risks.

Q. - Now as I understand it, in the first section of this list of high risks NB Power has identified approximately ten high risks associated with licensing or the regulator's decision ultimately on how things should go forward, is that correct?

MR. WHITE: That's correct.

Q. - The first one is that -- that would change the scope of the project of course, so the first one is CNSC requires improvements in -- I assume this is the emergency core cooling system --

MR. WHITE: That is correct.

Q. - -- that would require improvements in its unavailability. Can you explain why that's a risk and what that means?

MR. WHITE: This is a special safety system and we predict the future unavailability. In other words, we want to have a high degree of confidence that the system will be available when required under emergency condition, and there is a target for its unavailability and the design of the system originally is short of that target, and the regulator has been encouraging us to improve that system over time to improve that unavailability, and we are currently doing that in this outage.

Q. - So the work you are doing on this outage, will that eliminate this risk?

MR. WHITE: It mitigates it to a very low level. We made a commitment, I believe the year was 1997, with the regulator to install the additional equipment to essentially automate the process of moving from a medium pressure to low pressure emergency cooling, and we are installing that during this outage. We installed part of it in the 2000 outage and we will instal the remainder of it during this outage.

Q. - Can you explain what this emergency core cooling system is for? Why does it need to be available? What does it

do?

MR. WHITE: The important element in a nuclear power plant is ensuring that the reactor fuel is cooled at all times, and under an accident condition that would cause a loss of coolant from the normal heat transport system, the emergency core cooling system would inject ordinary light water into that system to provide cooling.

Q. - So this suggests that sometimes it's unavailable to be -- to do that -- provide that function in the case of an accident?

MR. WHITE: It has a very high availability requirement.

Q. - Now that availability requirement you are saying originally is lower than I guess the current standard, is that what you are trying to explain here?

MR. WHITE: That's correct.

Q. - So the risk in fact is the case that it would be if the Canadian Nuclear Safety Commission requires the availability of the emergency core cooling system to meet current standards?

MR. WHITE: The emergency core cooling system has been accepted by the regulator on the basis of the design that was installed in the station, and where that design didn't meet the future unavailability targets, the regulator has encouraged us to improve upon those targets and as such we

have undertaken this piece of work to do that.

Q. - In the -- in a Board decision on this question, could they require you to do further work to increase -- or reduce the unavailability of this safety system?

MR. WHITE: Obviously the answer is yes, they always could, but staff is -- has indicated their satisfaction with us completing it to the level that has been defined.

Q. - The next risk identified here is that the regulator forces the installation of a more extensive severe accident containment heat sink. Can you explain the nature of that risk, please?

MR. WHITE: I think I will ask Mr. Groom if he would handle that.

MR. COON: Very good.

MR. GROOM: Yes. The issue here is about the possible requirement to augment our existing heat sink removal facilities which, by the same criteria Mr. White has identified, meet the current regulatory requirements.

MR. COON: Could you explain in layman's language what it would mean to have to have to augment this containment heat sink?

MR. GROOM: They may require more heat removal capacity from the containment structure itself. This would be in the form of local air coolers or potentially coolers that

could remove heat from the water that would come from the emergency core cooling system, which -- dousing systems, that is. So it would involve putting some -- in simple terms, it could involve putting some additional heat exchangers in.

Q. - Is this effectively done to reduce the pressure in the building in the event of an accident?

MR. GROOM: The issue is to try and remove the heat. Obviously removing the heat would have the effect of reducing the pressure.

Q. - Thank you. The third point here is that the regulator might force increased scope of severe accident management instrumentation. Could you explain why that's a high risk to the project?

MR. GROOM: Do you mind if I just -- would you repeat it again.

Q. - I will try. CNSC forces increased scope of severe accident management instrumentation.

MR. GROOM: This is to provide additional -- the potential to provide additional instrumentation for monitoring the conditions in the reactor following a postulated accident. So for example, if we had a loss of coolant accident then this would be able to continue longterm monitoring of the reactor core or the conditions of the pressure. I might

add that the existing facilities which are in place in Point Lepreau do meet current requirements.

Q. - What sorts of detectors would these be and what would they be monitoring for?

MR. GROOM: Well this is a hypothetical question because the -- this risk was put in place was to address the possibility that some new criteria may be identified at some future date. But I gave some examples in the answer I gave you a minute ago. That would be potentially temperature and pressure and containment, as an example.

Q. - Would any types of flux detectors fit into this category?

MR. GROOM: That hasn't been identified as an issue because of course we have flux detectors already present in the reactor design. I might add that there is in the business case included some funds for this as a part of the cost estimate.

Q. - Thank you. Now the next point that was identified as a high risk to refurbishment was additional moderator sub-cooling margin might be required. Would you explain why that would be a high risk?

MR. GROOM: Yes. This is an issue, as Mr. White identified. I think I mentioned earlier as a part of our design of the seamless Calandria tube we have modified the surface in order to improve heat transfer from the Calandria tubes to

the moderator, and we expect that this will improve the efficiency of the thermal transfer into the moderator.

The question here is whether we have also in addition in the scope of work included improvements to our moderator heat exchangers to improve their capacity to remove heat. We think that this will be sufficient -- provide the necessary and sufficient design features. This item was put in place for what we think to be a low possibility that new criteria may be identified by the regulator over and above that which we are providing.

Q. - Why would it be so important to further cool the moderator, increasing the margin?

MR. GROOM: The issue for this particular scenario is in the postulated accident where the fuel is improperly cooled following an accident, resulting in the fuel being -- relying on the moderator as a back-up heat sink, and this is to ensure that the moderator has the capacity and capability to provide the necessary fuel cooling.

MR. WHITE: I might point out in our discussion of these risks that these risks could be high impact if they occurred, but for the majority of cases we don't see them as high probabilities of occurrence, but we wanted to make sure we thoroughly investigated them because of the potential impact.

Q. - Thank you, Mr. White, for that clarification. So in describing them as 24 high risks you are talking about them as having a high impact on the refurbishment project as opposed to having a high probability of occurring?

MR. WHITE: Yes. In terms of trying to quantify risk for the purposes of pricing and scoping here you need to identify whether risks are either high impact or low impact or whether they are high probability of occurring or low probability of occurring. So as you picked out the risk on Calandria tubes not being qualified, that would take us from something that's maybe a $3 million program to qualify that Calandria tube to maybe a ten or $15 million so -- although we don't think the probability is very high it does have an impact that's several million dollars.

Q. - Okay. So these are high impacts if they occur but your sense is that the regulator is not going to pursue these, correct?

MR. WHITE: Well we know that they will pursue some. As an example the first one on unavailability we are already doing that one, so that we know that one was going to occur and therefore we did include it in our list.

Q. - Very good. Just to finish this off then, we have design changes arising from the probabilistic safety analysis.

Who would like to handle that one?

MR. EAGLES: As part of the assessment work that was carried out in Phase 1 we looked at both the generic probabilistic safety analysis that is done for CANDU-6 reactors as well as the probabilistic safety analysis that has been carried out for other reactors world-wide. And in carrying out sort of an initial level of review on those works we have identified a number of items that should be reviewed in the context of our project. Those which we felt were important to consider we have considered and have discussed with the regulator. The actual conduct of the probabilistic safety analysis will -- has already started and will continue through till about the commencement of the outage, at which time we would expect it to be complete. And this item was put on our list to identify that possibly through the course of that work there may be additional items that we should consider. We believe that all of those which have any significant impact on the project have been considered already.

Q. - But the point being that if design changes did arise from this safety analysis, then that would have a high impact on the refurbishment project?

MR. GROOM: Again it depends on the nature of the item that might be uncovered, and of course those which have been

already discussed in generic PSA models or in PSA models that exist for specific plants, have been reviewed thoroughly and so we don't believe there will be any significant additional works.

Q. - Let's move on to the next one. Well let me skip one here and go to commissioning scope for the safety systems. What is the -- what kind of -- why would the risk be significant from that?

MR. EAGLES: Within the project schedule we have built a period of time to conduct the works of commissioning the plant and commissioning entails demonstrating that all those systems that have been changed are in fact functioning the way they were intended, and also a requirement to demonstrate that all the safety systems are in fact functional, whether they have been modified or whether they have just been laid up or whether they have not been operating as a result of the extended outage. The question here is whether or not there are additional tests that might be required beyond those which we have included in our -- in our project schedule. We believe that the discussions we will have with the regulator on an ongoing basis will resolve this matter and certainly allow us to build any additional testing that might be required into the schedule without significant impact on the

project, but again we felt it prudent to address this as one possibility of additional works for our purpose on returning the unit to service.

Q. - And then you have a point that says the CNSC could insist that commissioning address perceived deficiencies from the initial commissioning process, and you use the performance test of the emergency core cooling system as an example. What kind of -- why would this pose a high risk to the project?

MR. EAGLES: Again this item is not substantially different from the previous item that we just talked about, what are the requirements for the commissioning program, and those requirements will be fully discussed with the regulator and we will build them into our schedule as required. This issue was raised to say that are there tests that are beyond the scope of those that were originally conducted that may need to be carried out during this time frame. It's our proposal that we wouldn't conduct further tests, I guess tests beyond the scope of the original testing that was done to put the plant in service, but if there are any, then we want to have identified that, have those discussions with the regulator and build them into the schedule so that they can be conducted in the appropriately timely fashion to get the unit back on line.

Q. - Correct. So the issue of course is whether or not the Commissioners will decide to make these requirements as opposed to your particular proposals, correct?

MR. EAGLES: Again this is another area where we conduct a number of discussions and have had exchange of information with the regulator and will continue to have exchange with the regulator as we develop the plans right down to the final level of detail as to what is implemented in the field. At the end of the day the CNSC staff has a Board of Commissioners to respond to as well.

Q. - The next point here is training program for licensed operators for project work as particularly imposing high risk to the refurbishment project. Can you explain why?

MR. WHITE: I might handle that issue. There is significant training requirement on an ongoing basis for certified operators for the station and during the period of time that the station is not operational those people are not in their normal operating environment gaining the normal feedback from carrying out their duties on a regular basis. And we will go through extensive simulator testing and those kind of things to maintain qualifications, but we may also be in the position where some of those operators might need to spend time in some other nuclear plant in order to maintain those skills from a licence

basis with our nuclear regulator, and therefore their availability for project work may be more limited as a result of that.

Q. - So that the risk to the refurbishment project is you would have a -- kind of a weakness on the personnel side in terms of carrying out the work?

MR. WHITE: The risk is have we properly accounted for the amount of time that will be necessary in training to maintain the licence qualifications when the plant is in a shut-down state.

Q. - This is about not coming up short.

MR. WHITE: Yes.

Q. - Yes. And then finally the current licence risk -- not finally but the end of list, the current licence risk, what does that mean?

MR. WHITE: Well as Mr. Pilkington spoke to, we have a number of improvement programs and some of those are part of requirements within our licences, and of course we have to make appropriate progress on all of those things. So we just wanted to highlight that as an item that we need to keep our attention and focus on.

Q. - So is the point -- to clarify here, is the point that if you don't keep on top of those current activities that it could have an impact on the refurbishment project in some

way?

MR. WHITE: Well certainly we need to ensure that we maintain good licence compliance in the running plant at the same time as we are looking at the refurbishment processes.

Q. - Okay. Now the last point here which I'm going to ask Mr. Thompson to ask some questions about is the relocation of steam lines on main control room roof as potentially having a high impact on the refurbishment project proposal if the licensee -- or the safety commission requires you to make that relocation.

MR. THOMPSON: I am not sure who to direct this to. I see some information on the evidence of Mr. Groom here. Okay.

Relocation of the steam lines on the main control room route, can you tell us in a way we can understand, you know, what these main steam lines are, and what they are like? You know, the size of them and that sort of thing, exactly what they do, where they start and where they end going, you know, over the control room roof?

MR. WHITE: The steam lines carry steam from the boilers that are in the reactor building. And they carry it to the turbine which is in the turbine building. And between those two buildings is the service building which is where the control room is located. And the particular routing

of these steam lines actually sit on top of the control room roof.

And the issue in the past with the regulator has been if we should have a fracture in one of those steam lines, would it damage the control room in such a way that it might become uninhabitable in terms of being able to properly shut down the reactor.

And to respond to that we have built a secondary control room that is fully capable of shutting down the reactor. And it is manned by an operator on an ongoing basis.

In addition to that, we have also put on an on line monitoring system that monitors any particular moisture content between the pipe and the insulation that's on the pipe to detect any early evidence of potential problems in those lines.

And that has all been agreed with our regulator in past days. And we wanted to ensure that that issue would not arise again during the refurbishment. Because we saw no need to do additional work, but we wanted to make sure that within the minds of the regulator that they also concurred with that.

And that's referred to in the letter of comfort that the staff indicate that they see no reason to bring that

item forward to their Commission in the future.

MR. THOMPSON: Can you -- can you point us to where that is in the -- in the letter of comfort so we can see that?

MR. WHITE: It's in document A-1, my evidence. And I believe it's on page -- it's under section 6.32 of the nuclear regulator letter of December the -- December 2000.

MR. THOMPSON: It's under 6?

MR. WHITE: 6.32.

MR. THOMPSON: 6.32.

MR. WHITE: And the concluding statement says that the analysis would support the decision taken by the Commission -- sorry, have you been able to find that?

MR. THOMPSON: Not yet.

MR. WHITE: Appendix A-1 to my evidence in that book.

MR. THOMPSON: Okay.

MR. WHITE: And that's about 10 or 12 pages into that. And there are section numbers?

MR. THOMPSON: Yes.

MR. WHITE: And it's 6.32 at the top of the page?

MR. THOMPSON: I have that.

MR. WHITE: And halfway down the page just before it goes to 6.33 it says, "Regarding the specific benefit cost analysis submission relative to relocating secondary side piping, CNSC found that some of the input frequencies

appear unjustifiably low. However, we also acknowledge that even with larger frequencies the analysis would support the decision taken by the Commission to accept the current location of the piping, given the new mitigating equipment and procedures. Unless new information warrants, it is unlikely that the CNSC staff would raise this issue to the Commission in the future."

MR. THOMPSON: Thank you.

Q. - So as in the case of the technical issues identified there that could have a high impact on the proposed refurbishment project in terms of its scope then, Mr. White, you would agree that based on these issues potentially high impact on the project from a licencing perspective, that decisions made by the Nuclear Safety Commission could have a significant impact on the scope of the project?

MR. WHITE: Important decisions to this project from a list we have identified ones that could be significant, yes. And we have also taken action to quantify them and deal with them.

Q. - Now could I have a moment here, Mr. Chairman? Okay. A little later -- a little later in those same minutes we have been working off of from December the 18th on page 18, part 4, Project Risks and Mitigation. This is part of

a Board presentation on refurbishment following the table we have been working off of.

MR. SOLLOWS: December or November?

MR. COON: December 18th 2001. It's an attachment to the last part of the minutes. Board presentation Point Lepreau Refurbishment Part 4, Project Risks and Mitigation.

Now, Mr. White, this is part of a presentation that was made to the Board on December -- the Board of NB Power on December the 18th. Was this presentation prepared by yourself or under your direction?

MR. WHITE: It was under my direction. This piece was actually done by Mr. Eagles.

Q. - Okay. So we have got you both here, that's good. So on this page 18 there is a section entitled, "Technical and Licencing Risks". Several areas of risk are identified. Is it fair to say that the risk element in this case is the impact of these factors on the capital cost, delays causing increased replacement power costs, delays causing increased interest during construction and increased commissioning time?

MR. WHITE: You are certainly accurate in the first two. The next two would have to be looked at in a little more detail to be sure of whether they impact those or not.

Q. - So these elements here, the impact would be definitely on the capital cost and delays causing increased replacement power. And you are saying you would have to look at whether there would be impacts in terms of delays causing increased interest during construction and increased commissioning time, is that --

MR. WHITE: Well, if you delayed the completion of the project, obviously that would increase IDC, as you pointed out. And if there was more work to be executed, then that probably means more commissioning time.

Q. - Thank you. Are there other elements besides those ones of licencing risks which would -- would be encompassed by these areas of risk?

MR. WHITE: I'm not sure exactly what you are referring to there. Maybe you could expand a little bit?

Q. - Well, I guess the question is are there other risk elements in terms of impacts beyond the ones we just discussed, relating to these areas of risk?

MR. WHITE: I think we have identified the ones that we think are significant. And that, of course, in a project of this magnitude there is always a lot of low level ones that you deal with on an ongoing basis.

Q. - Oh, I meant in terms of the actual elements. In other words, impacting on things like capital cost, delays

causing more replacement power costs, are there other elements that -- beyond the ones we have listed here that might -- we might include, or have we covered them all?

MR. EAGLES: Well, I think, if I might add here, that in the -- in the identification of risk areas we tried to incorporate all of those which we thought would have an impact on the project. Two of the ones listed on this page that you see, moderator inlet nozzles and Calandria tubesheet weld ductility I don't know if they were on the previous document. They were on that document as well?

MR. WHITE: They were there but they weren't in detail. They were part of our internal reactor components.

MR. EAGLES: So those, you know, are specific ones that we had dispositioned through our analysis work early on to a point where we believe the probability is not just low, but very, very, very low. And so we identified those here.

So, of course, as you go through a process of project management identification and management of risks of that project are key to the success. And that's what we were attempting to do and have -- I believe we have done through -- through the identification of these risk areas.

Q. - I guess I'm wondering among the licencing risks whether you would consider the requirement by the Canadian Nuclear

Safety Commission to -- if it made this decision in a couple of weeks to require a EIA of the refurbishment project, in order words, broaden the scope of the current proposed EIA for Point Lepreau, whether or not that is a licencing -- risk of the licencer that would affect the project?

MR. WHITE: Well it would probably involve more work. It's not something that we think is -- as I quoted, was quoted in the newspaper, would be unnecessary because of the legal requirement as well as the fact that Lepreau has already had two environmental impact assessments and full panel hearing processes. And therefore we think, I believe, it would be unnecessary to go there.

If the Commission should rule that, then obviously that means more work in terms of completing the documentation and completing the process that would be necessary there. But that work is earlier in the project here. And so we still have float time to be able to deal with that.

Q. - Would it affect your critical path and time line in any way?

MR. WHITE: Again, the EA as currently proposed in front of the CNSC has a date on it of, I believe it's July of 2003 for completion. And if the CNSC Commission were to expand

the scope of that, we would need to look at what the impact of that is.

But we would have float between the completion of that EA and the start of construction of waste sites, which is in April of 2004. So have a fair bit of float to be able to deal with any repercussions from that.

Q. - On this page 18, the first area of licencing risk identified is the risk that the CNSC would require changes beyond the planned scope. When you say planned scope, are you referring to the licencing framework document scope contained there?

MR. WHITE: You are still on page 18 here?

Q. - Yes. In the first point here it says an area of risk is if CNSC requires changes beyond the planned scope. And I'm just asking whether when you refer to the planned scope you are referring to the scope as it's laid out in the licencing framework document?

MR. WHITE: That is correct.

Q. - Yes. Thank you. Under "Areas of Risk" here there is a bullet which lists low probability and high cost events in the second point.

Now do you refer to them as low probability in the sense that the probability is low that the regulator will require NB Power to address these safety issues? Or is

there a low probability -- well, you tell me.

MR. WHITE: Well, if you look at the first one and the last one on that list, moderator inlet nozzles and Calandria tubesheet weld ductility, this is looking at whether the welds in fact are still flexible and that they haven't become hardened.

And we have done the analytical work on that that says that those welds should be all right for an extended life of 50 years. But if in fact they do exhibit less ductility then we would have to look at what remedial program.

And where you are inside the reactor vessel, that is a more difficult area to get at and work. And so we would see that as being high cost if it occurred.

But the fact that we have done the analytical work and that there is no predicted issue there, we see it has a low probability of occurring.

Q. - So the probability referred to here is as to whether it will occur or not as opposed to whether CNSC will require some change?

MR. WHITE: That is correct.

Q. - Yes. Okay. And you refer to them as high cost because they would be expensive to address in the eventuality that the regulator required action in these areas?

MR. WHITE: They would be high cost in terms of whether the technical nature of the issue required us to do work. And I'm sure if we had that technical issue, the CNSC would certainly be involved in overviewing how we handled it.

Q. - Some of these others came up before. But could you describe what the safety issue is with respect to the moderator inlet nozzles listed here as low probability, high cost?

MR. WHITE: I can ask Mr. Eagles to speak to that. But basically it is around the ductility of the welds on those nozzles again.

MR. EAGLES: This particular risk item was raised by work that we had conducted during the Phase 1 as a result of an issue that arose I believe at the Pickering reactor under certain operating condition that they had.

The analysis that we had conducted and the designer view that we had undertaken to disposition this particular item showed that our design was more robust than that which was installed at Pickering in the early reactors, and that the stresses on the individual components there in the moderator inlet nozzle were much lower as a result.

And that analysis, as I mentioned a moment ago, took any concern that was raised -- and this is using operating experience to look back at what happened in the industry

and are there any things that we should consider. And it took that experience and dispositioned it to a very, very, very low level, that we don't believe that there is any concern here for us.

This is part again of the inspection work that would be intended to be conducted during the reactor assembly inspections. But again the work that we have done to date would take this into the low, low level. We have identified them here. And in fact I don't believe that one was specifically mentioned on the previous list --

Q. - No.

MR. EAGLES: -- because it was taken basically off of our list of very high issues. But again in prudence we want to make sure that our Board is understanding of the things that we have attempted to deal with here and feel that we have dealt with.

Q. - These moderator inlet nozzles are on the interior of the reactor Calandria?

MR. EAGLES: This is the connection from the supply pipe for the moderator circulating system that takes moderator water out to the key exchangers and pumps it back to the Calandria vessel. So this was the nozzle that is inside the vessel itself.

Q. - So it is inside. So that is why you would only be able

to determine for sure if the retubing went ahead and you could get access to have a peek?

MR. EAGLES: Yes.

Q. - If there was a problem would they need to be redesigned or simply replaced? Or what would you do?

MR. EAGLES: My recollection is that if there was an issue there, what we would have to do is to look at whether or not the issue that is there is possible to be dispositioned in place or whether or not remedial work would have to be done. And if that is the case then remote tooling, as is used throughout the nuclear industry, would be utilized to make a repair.

But again the review of the design that we have says that we have a robust design. And the analysis conducted suggests that probably we should never have mentioned this because it is so low down. But we wanted to make sure our review was thorough.

Q. - Would there be implications for any other components if there was a problem with these nozzles?

MR. EAGLES: I don't believe so.

Q. - Stand alone? Okay. This I guess you have already identified. When you say this is in the category of high cost events, I guess, if there was a problem, what sort of cost implications would there be?

MR. EAGLES: I couldn't answer that at this time. And the question is because of the nature of the work and the location really would impact on the critical path, the outage, if there was something substantial that had to be done.

And in that sense it would create a high cost. But again the probabilities we believe to be nonexistent.

Q. - We talked earlier about the moderator recovering system and the PVC cables. Could you explain the safety issue with respect to the Calandria tubesheets weld ductility?

MR. EAGLES: Perhaps I should turn that to our metallurgist.

MR. GROOM: Yes. I think Mr. White addressed this earlier when he talked about weldments and the possibility that they may suffer from radiation effects in service.

And he identified in his answer to you a little earlier that we would do inspections of those to see if there is any evidence.

And so this is a part of the -- one of the welded areas that we would be looking at as a part of our inspection program. That particular one is a connection between the tubesheet and the Calandria shelf.

Q. - Just a question on those PVC cables. Do they meet the current standards for new nuclear plants?

MR. GROOM: The PVC cables in operation do meet the current

standards for nuclear power, yes.

Q. - Now under "Mitigation Strategies" here, number 2, you have "AECL Review of Low Probability and High Cost Events."

Am I correct in inferring from this that AECL will carry out or is carrying out these studies for NB Power?

MR. EAGLES: Yes. The two in particular that we just talked about, the moderator inlet nozzle and the Calandria tubesheet weld ductility were specifically addressed by AECL in analysis to determine whether or not there would be a problem with the weldment.

So again it was that analysis that was conducted using experience from the industry, nuclear industry worldwide to disposition these things.

Q. - Does or will AECL use a type of benefit cost analysis for these studies?

MR. EAGLES: Benefit cost analyses are not used in these studies. These studies were analyses as to whether there was any issue with the weldments.

Q. - Of course the Canadian Nuclear Safety Commission has the authority to accept or reject the conclusions of AECL in this matter, is that correct?

MR. EAGLES: These are not the issues. I don't believe that we have proposed I guess with the nuclear regulator. But

I would have to discuss that further with some of our co-workers.

MR. WHITE: Just to answer that on a broad basis, the Canadian Nuclear Safety Commission oversees all activities of our plant. And they have oversight on everything related to the safety and operation of the station.

MR. COON: Thank you, Mr. White.

CHAIRMAN: Mr. Coon, is this an appropriate place to take a break?

MR. COON: Indeed.

CHAIRMAN: Okay. We will take a 15-minute recess.

(Recess - 2:45 p.m. - 3:05 p.m.)

CHAIRMAN: Mr. Groom has indicated that he has gotten the information on a further undertaking, so Mr. Groom go ahead.

MR. GROOM: This was in regard to a question that was asked this morning related to experience with Calandria tubes, Calandria tube removals. And I now have the information.

They are in the NRX reactor. There has been a complete change out of the Calandria vessel. This has included the numerous flow tubes that are made from aluminum, so not entirely the same material. And alloy is the ones that we use.

In the NRU reactor there have been numerous zircaloy

tubes replaced over NRU's life. And these are similar but the joining technique is a little different.

I think the more relevant experience comes from the operating reactors. And as I mentioned in the Douglas Point reactor there had been one Calandria tube change there. That was done in 1966, '67.

In the Pickering reactor and the Pickering Unit 2, there has been two tubes changed. And in Pickering Unit 4, there have been also two tubes changed there. And in the Bruce reactor there has been one tube changed. So that is experience.

And I think the point is that the work at the reactor face, doing this sorts of work and task, is not a lot different from the kind of work we do on a fairly routine basis at the reactor face during normal maintenance outages.

Q. - Thank you, Mr. Groom. So just to be clear then, there has been since the 60s four Calandria tubes removed and replaced in commercially operating reactors?

MR. GROOM: No. I think I said -- I'm sorry, I didn't hear you but I said there were -- there has been a total of five -- six, excuse me, four at Pickering, one at Bruce and one at Douglas Point.

Q. - Yes. Correct, six. And then the research reactor at

Chalk River is the one you are referring to as NRX, is that --

MR. GROOM: Yes. NRX and NRU. And NRU has had numerous zircaloy tubes replaced over the life. They didn't actually quantify them, but --

Q. - In the case of NRX you said that all of the tubes were replaced?

MR. GROOM: Well in NRX the entire reactor vessel has been -- the reactor core assembly has been changed including all the tubes.

Q. - They replaced the vessel too?

MR. GROOM: Affirmative. And they have done that three times.

Q. - Okay. So that is the research reactor there. So as you say the relevant experience would be the six removals and replacements of the commercial plants?

MR. GROOM: Yes.

Q. - Yes. Thank you very much for that. Okay. We were still on the same document. But I would like to flip back to page 10. It is a little bit off topic but instead of having people to dig out this area of minutes out again, I thought --

CHAIRMAN: This is still the minutes of December 18, 2001?

Q. - Still the minutes of December the 18th. If you flip back

to page 10 to something called part two of the business case. And it is a bit of a departure, perhaps a welcome departure from the line of questioning. But the second point, there is a reference made under the bullet to a probabilistic assessment of project risks by Ernst & Young. Now I don't remember seeing it anywhere but it may well be in one of those binders. Has that analysis been provided as evidence in response to interrogatories or motions?

MR. WHITE: I'm sorry, Mr. Coon, I must be in the wrong place. It was on page 10?

Q. - 10, yes. That is part two business case project costs estimates.

MR. WHITE: Yes. And which --

Q. - And referring to the probabilistic assessment of project risks carried out by Ernst & Young. Have you got it?

MR. WHITE: Yes.

Q. - And my question simply was -- I don't recall it but it may be there -- and that was whether it has been provided in evidence as part of any of the interrogatory responses or response to motions?

MR. WHITE: We provided the summary of the key risks areas and that is what we have been talking about today.

Q. - But the Ernst & Young, the study, entitled "Probabilistic

Assessment of Project Risks"?

MR. WHITE: No. We did not file that. We have just identified the key risks that we have here.

Q. - Would you undertake to provide a copy of the Ernst & Young assessment as an exhibit for this hearing?

MR. WHITE: I think all the material elements are already included in the key risks that we have identified here. There are only other minor risks here in this process.

Q. - I guess the point is that -- Mr. Chairman, that when we get to Panel 2, this project has a clearly significantly higher risks than any of the alternatives that will be considered. Well, that is for you to decide of course. But it will be compared with these other alternatives and this information would appear to be quite relevant in evaluating this proposal as compared to the alternatives.

CHAIRMAN: Mr. Hashey, Mr. Morrison, anything you want to say to that?

MR. HASHEY: I think that is one we better take under advisement. I wonder -- you know, how many books do we fill before this is over? I mean, there has been a request for everything, and everything and everything. I'm not sure that has relevance but I will inquire and maybe could give an answer later today or first thing tomorrow, Mr. Chairman.

CHAIRMAN: Well, in fairness, I think why don't you obtain it yourself, look at it and tell us what you want to do.

MR. HASHEY: I have never seen it.

CHAIRMAN: No. I say -- so have them get it and if you don't wish to put it in evidence then we will have an argument and the Board will rule. But otherwise you will have it and you can see what is there.

MR. HASHEY: Okay. That is fair. Thank you.

CHAIRMAN: Good.

Q. - Okay. I think we can put the minutes away for now. We will just carry through two of the high risks -- the high risk licencing areas in here related to the commissioning process. And there is relevant information there in exhibit A-5 to commissioning. And that would be CCNB 21.

MR. DUMONT: Can you repeat that please?

Q. - CCNB 21 in A-5. Now this relates to the commissioning process in the minutes we were just dealing with. Two of the high risks licencing areas relate to that process of commissioning, that is the reactor after its -- if it were refurbished and to bring it back on line.

In response to this interrogatory 21 of ours the evidence indicates that the work plant is to have the reactor become critical on July 29th 2007 with full power established by the end of August 28th 2007 and then full

commercial operation by the end of September of that year.

So maybe this is Mr. Eagles, am I correct in assuming you expect to commission that -- the reactor in 60 days if you were to go ahead and refurbish?

MR. EAGLES: Two months is what I reported yesterday in my presentation, yes.

Q. - Thank you. Now we flip to exhibit A-1 of the pre-filed evidence. Slowly making progress on Mr. White's evidence here at page 13.

In response to question 14, Mr. White, you say that the nuclear plant's operating licence must be formally renewed currently every two years. When does the current licence expire?

MR. WHITE: In October 31st 2002.

Q. - October 31st 2002. Would it be possible to renew the operating licence if the reactor is shut down for refurbishment if it coincides with the time of licence renewal on the current schedule?

MR. WHITE: Yes.

Q. - So it would be possible to renew the operating licence if the reactor was shut down for refurbishment?

MR. WHITE: Yes.

Q. - Should the refurbishment take longer than expected is it possible that the reactor would be shut down long enough

for the licence to expire?

MR. WHITE: Well that really depends on the licencing time frames. The current licences I say expires in October. We have already filed submission for renewal of that licence.

We have applied for the a three year licence. It is our understanding that the staff will recommend three years and two months. And that will take us till December 31st 2005. And we would then propose that the next licencing sequence goes beyond the restart of the reactor. And this is part of the Canadian Nuclear Safety Commission approach to lengthening licence times. And depending on how you are rated with the regulator today and how their commission rules, they can decide on time frames that are probably up to five years. That is what they have put forward in their recent staff presentations to the commission on reactor licencing times.

And so we foresee that the regulator is moving to a longer licencing interval. And in our case we strategically discussed with staff and setup that our licence would expire at the end of December of 2005 and the next licence interval we would project would then go pass the restart of the reactor.

Q. - How long would the refurbishment have to take for you to

end up having your licence expire during that period?

MR. WHITE: Well that is all conjecture. Because, you know, I said to you that staff are recommending a 2005 licence. But again the commission has to rule on it. And then the next licencing period beyond that is pure conjecture. We know that the staff -- or the commission is considering longer licence intervals. And how long they would consider it and how long they will approve is pure conjecture.

Q. - Thank you for that. We will go back to the comfort -- or go forward, I'm sorry, to the regulator's letter, staff letter from the regulator, Appendix A-1.

Yes, this letter is from -- yes, this letter is from Mr. P. Hawley, Acting Director of Power Reactor Evaluation Division of the Canadian Nuclear Safety Commission.

Now it was written in response to a request made by yourself, Mr. White, to J. D. Harvie, the Director General at the Director of Reactor Regulation at the Canadian Nuclear Safety Commission, is that correct?

MR. WHITE: That is correct.

Q. - The original request then went to Mr. Harvie, Director General of Reactor Regulation. A response came back from Mr. Hawley, the Acting Director of the Power Reactor Evaluation Division.

Is Mr. Harvie the immediate supervisor of Mr. Hawley?

MR. WHITE: Yes. He was at that time.

Q. - Why doesn't -- didn't Mr. Harvie respond directly to your letter?

MR. WHITE: Mr. Harvie appointed Mr. Hawley as the Acting Project Director for consideration of the refurbishment work at Point Lepreau.

Q. - Thank you. Do you know what divisions of the Canadian Nuclear Safety Commission that are under the supervision of the Director General, Mr. Harvie?

MR. WHITE: Mr. Harvie has now retired. But at this point in time he was responsible for Power Reactor Operations Division.

Q. - Is there a reason staff from other divisions did not supply a so-called comfort letter for you, for example, regarding the -- from the Waste and Decommissioning Divisions regarding the plans filed there?

MR. WHITE: Mr. Harvie appointed Mr. Hawley to be the overall CNSC Project Director for this project to coordinate all activities relevant to it.

Q. - Thank you. How many layers of management are there between Mr. Hawley and the Commissioners at the CNSC?

MR. WHITE: Mr. Hawley to Mr. Harvie. Mr. Harvie reports direct to Linda Kean, who is the President of the CNSC and

Chair of the Commission.

Q. - So that would make two?

MR. WHITE: Yes.

Q. - Thank you. Within the CNSC is the Power Reactor Evaluation Division the only division which has input into the CNSC regulation of the Point Lepreau nuclear reactor?

MR. WHITE: No. We also have a waste site licence.

Q. - And which division would be involved there? That would be the Waste and Decommissioning Division, I suppose?

MR. WHITE: I don't know the official title. But it is like Nuclear Substance and Waste, I think, something like that.

Q. - Thank you. But there aren't any other divisions which have direct input into the regulation of the Point Lepreau operation itself besides the waste side of things?

MR. WHITE: Well, there are many other components of the CNSC covering issues like training and quality assurance. And these are all other directorates within the CNSC that carry out oversight and evaluation duties for reactor licencees.

Q. - Then there are other divisions which would have input into the regulation of Point Lepreau's power plant?

MR. WHITE: That is correct.

Q. - So besides the Waste Division, which other divisions would have input?

MR. WHITE: Well, I mentioned that quality assurance, human factors and training. The CNSC subsequent to the date of this letter have reorganized themselves in slightly different format than existed at the time of this letter.

Q. - Okay. We will stick with this letter. And if I could also get you to open up exhibit A-6. Under the tab CCNB 19 there is a licencing framework document.

What I want to do is refer back and forth between the licencing framework document and the attachment to the letter from Mr. Hawley.

So if we go to page 55 of this licencing framework document there is section 6 titled "Expectations of Agreement." And in the attachment to Mr. Hawley's letter there is also section 6, "CNSC Staff Responses."

So in the attachment to Mr. Hawley's letter, he responds point by point to the requests which are include in this section.

If we compare the two documents, it would appear that we could get an understanding of what NB Power requested versus what the staff within the Power Reactor Evaluation Division was prepared to agree to.

Would you agree with that --

MR. WHITE: That is correct.

Q. - -- if we make this comparison?

Well, the first listed request by NB Power is on page 55 of the licencing framework document 6.11. And that is the agreement on the scope, schedule and methodology for EA.

The first request is that the CNSC staff agree to the scope as identified in "EA Scope, Version 3", the first line here.

Can you summarize, Mr. White, what you are asking here for in this request and why it was important to reducing regulatory risk?

MR. WHITE: We recognized from looking at the legal requirements in Canada that a environmental assessment would be triggered by a change to the waste site licence when we would apply for construction of additional structures to handle reactor wastes. And that triggers an EA on the waste site licence.

And, therefore, defining what is the scope of that environmental assessment is a pragmatic approach to understanding the amount of work that would be required and therefore understanding where you fit it in the schedule and what the costs would be.

Q. - Now in the attachment under "CNSC Staff Responses", the attachment to Mr. Holly's letter, he says in the second paragraph under "CNSC Staff Responses", he says "CNSC

staff cannot agree at this time to that request."

And they go on to describe the process they are involved in and that they expect to have a staff scoping document by March of this year.

At this time has the Canadian Nuclear Safety Commission approved NB Power's request that they agree to the scope as identified in what you call your environmental assessment or EA scope version 3?

MR. WHITE: I don't believe that the reference to version 3 is the current scope that is in front of the CNSC for a decision.

A lot of water has passed under the bridge since then in terms of internally trying to come to grips with what environmental scope would be appropriate and whether they term this work that we are doing life extension, maintenance outage and how it affects the operating licence which was some of your questions on the earlier ID 1.

And so the staff has ultimately created a position on that both with themselves as the responsible regulatory authority with the Environment New Brunswick and with the other federal and provincial agencies that feed into that process.

And that is the scope that they put in front of the

Commission on 22nd of May and the Commission is making their determination on now.

Q. - Thank you. Now if we could go to A-5, exhibit A-5. In exhibit A-5, response to CCNB 20, that is on page 78, the response is "NB Power does not expect the Canadian Nuclear Safety Commission to require the refurbished reactor to meet all current standards."

Is that correct still?

MR. WHITE: That is correct. We are required to meet the standards that are in the operating licence.

Q. - Right. And it goes on to say how NB Power examined how the plant compares to current codes and standards to assess the safety significance in the areas where there were deviations between standards that the plant meets currently and current standards?

MR. WHITE: That is correct.

Q. - Is this the same kind of analysis that the Canadian Nuclear Safety Commission -- that you would expect they would do to look at where deviations occur between current standards for new plants and standards that Point Lepreau meets?

MR. WHITE: CNSC has a consultative document out now that defines some of this processes. And we recognized that this would be an area that they would ask us to provide

information on.

And, therefore, we undertook to do that work to do a comparison so we would be able to proactively respond to that.

Q. - But as part of their job as a regulator of safe performance of nuclear reactors in Canada, I believe you would expect them, would you not, to look at the differences between new standards for new reactors and the current standards that Point Lepreau meets?

MR. WHITE: Any power plant that is constructed, nuclear, conventional or otherwise is constructed to a set of standards.

When you do upgrades to those facilities, you normally operate on the basis of those original design standards. And where you are adding modifications, then you may add them to updated codes as you have agreed with your regulator.

Q. - So CNSC will ultimately decide whether a refurbished Lepreau would have to meet standards now current for new power plants?

MR. WHITE: They would decide for that. And they identify those issues in operating licences. And we meet the requirements of the operating licence.

Q. - If we can go to exhibit A-13, Supplementaries. So CCNB

supplemental 6, in that supplementary question, at page 7 --

MR. MACNUTT: Could we have the reference again, please?

MR. COON: Certainly. Exhibit A-13, CCNB supplemental 6, page 7. It's about a third of the way in --

MR. WHITE: Yes, I have it.

Q. - But not all the commissioners have it. A-13, page -- CCNB supplemental 6. There is a bunch of stuff before it, but -- if you work back from the CCNB section it would be easier to find 6 than if you work frontwards I think.

Okay. In part A of that supplementary question we ask for you to please indicate the specific instances where the Point Lepreau plant does not meet the current codes and standards of the Canadian Nuclear Safety Commission, and this was not provided. So we are wondering can you please provide a list of these deviations?

MR. GROOM: I think we are on the wrong reference.

Q. - Supplemental 6. 6-A specifically, we asked to indicate the specific instances where the Point Lepreau nuclear plant does not meet current codes and standards of CNSC for new reactors. This was not supplied in the response and we are wondering if you can provide a list of these deviations for these hearings?

MR. WHITE: Again our requirement from a licence point of

view is to meet the codes and standards that are in the licence. This was a review we carried out against current codes and standards just to understand the deltas of those kinds of things, and they are part of the safety and licencing work that I think has been highlighted in the evidence presented. We may not have listed them specifically but they are part of that overall requirement -- or that evidence that is provided already.

Q. - You are saying that this analysis of the deviations that you carried out is part of the evidence? Can you direct us to it?

MR. WHITE: I'm saying that it's part of the licencing frame works that we have laid out. We have addressed any deviations that we think are appropriate as a result of codes and standards, reviews, and that we put these forward to the regulator as part of their review of our licencing frame work.

Q. - Given that the Canadian Nuclear Safety Commission may decide in its judgment to require certain of these new standards to be met by a refurbished Point Lepreau which could change the scope of the project considerably, we are asking if you can provide the information that shows how Point -- codes and standards Point Lepreau currently meets deviate from the current codes and standards for new

reactors?

MR. HASHEY: Mr. Chairman, surely there is a point -- we haven't interrupted -- I haven't interrupted here, but if we are dealing with a licence that is a current licence that we have to meet all the standards under that licence, and we have referenced them, we have discussed them and we have mentioned them, to take this to the point of saying, what if, maybe, may, what are the standards if we are going to build a new plant, we are not. If my learned friend had brought evidence forward that says that what we have presented is not relevant that's one thing, but I mean, we are getting down the road of speculation I think just far too far. I mean, this can go on forever on that direction. And I think the questions have been answered. We have not interrupted, fairly and thoroughly, but to get down into details of something that has no relevance or isn't shown to have any direct relevance other than a might, or a maybe, or a possibility or down the road I think is carrying it too far and I would object to that question or request that it not be required to be answered.

CHAIRMAN: Mr. Coon, what Mr. Hashey says certainly impacts with me that we would be in a continuing speculation mode. You know, if you want to respond to what he said please do

before we make a decision on it.

MR. COON: Yes, I would like a brief response, Mr. Chairman. This is about what magnitude of risks are involved here with respect to the ultimate scope of this project and the ultimate costs. And the power commission has done a review internally to look at what standards for new reactors are and how they compare with the current ones that Point Lepreau meets. And the risk of course is that CNSC, the regulator, could require a refurbished Point Lepreau to meet some or all of these new standards for new reactors given the significance of this project and the work that is being done -- that would be done to rebuild the nuclear reactor at Point Lepreau.

And it's important for us to understand here how that might contribute to a change in the scope of the project to the overall economics and business case.

The -- now I have lost my train of thought, but we will leave it at that I guess. Oh, I know what I was going to say, that NB Power based on looking at the differences between standards for new plants and what they currently have to meet, these are safety standards, have made certain changes in the scope of the project in ways they think will address or anticipate what CNSC might require, but we have no idea what CNSC might require and

if we don't know what the differences are between standards for new plants which may be applied to a refurbished Point Lepreau and the current standards, then we have no way of knowing in fact how much the scope of the project might change based on a CNSC decision.

CHAIRMAN: With all due deference, unless you are prepared to call a witness with expertise in that field, we will be no closer to knowing what the safety regulator might in fact require, Mr. Coon.

Anyway, the Board will just step out into the back hall here for a minute.

(Short Recess)

CHAIRMAN: All right. The Board has taken a few minutes to consider the request of Conservation Council that we order that the standards for new CANDU nuclear reactors be filed in this hearing, and the Board rules that NB Power should file those.

Now are we talking about a concise document? Are we talking about a series of documents? What can you suggest, Mr. White?

MR. WHITE: First off, may I help the Board here. We would file the deltas between what the current standards are and what our plant design is as we have filed them with the CNSC to date.

CHAIRMAN: Mr. Coon, does that satisfy what it is you are looking for?

MR. COON: Yes, Mr. Chairman.

CHAIRMAN: Okay. How long a process would it be for you to be able to do that, Mr. White, do you think?

MR. WHITE: I think they are readily retrievable from our data bases and that we probably can file them within the next day.

CHAIRMAN: Thank you.

Q. - So at this point, Mr. White, should NB Power be permitted to go ahead with this project you will find yourself seeking approvals from the nuclear regulator to undertake the project, is that correct?

MR. WHITE: May I just clarify seeking approvals for -- what was the last statement?

Q. - For the scope of the work to be done for the refurbished Point Lepreau.

MR. WHITE: We have outlined the scope in the framework documents and that is the scope that we believe generally is appropriate in terms of life extending this reactor, and we have got some level of comfort, that is in the comfort letter from the regulator relative to that scope. And so that's the scope that we have used in defining the costs and schedules.

Q. - Correct. But the Canadian Nuclear Safety Commission will ultimately rule on the details in terms of the scope of the project, in terms of what kinds of activities, upgrades, changes, improvements, standards and so on that you will have to meet, is that correct?

MR. WHITE: I think the answer is generally yes to that. The staff will I guess in due course decide what items are of the significance level that they need to take forward to their commission.

Q. - So as in the case of building Point Lepreau, the first CANDU 6 to be completed in Canada, NB Power will once again be a forerunner in seeking approvals for a project that has not been done before in Canada, correct?

MR. WHITE: I think the answer to that is that the process is very similar to ones that have gone on before where there are maybe changes that are required, as an example in the Pickering program, although it's quite different than this one, there were certain requirements of the Board that were agreed to be carried out.

And the Bruce program of restarting 3 and 4, they have also applied to the CNSC for scope determination on their EA, and they would also get concurrence with the CNSC on the things that they intend to do as part of re-start of that reactor. And the CNSC may place obligations on them

as part of that exercise.

So what is going on here is a reasonably normal course of interaction with the regulator, albeit that the regulator has not built many regulations around life extension. And so these are early on in the process of starting life extension discussions with the regulator.

Q. - So as you pointed out in constructing the first CANDU 6 or completing the first CANDU 6 in Canada, this puts you in an unenviable position to be a forerunner in doing the first life extension of a CANDU 6 in Canada with regards to the regulatory process and regulatory approvals, correct?

MR. WHITE: Yes, we are ploughing a little bit of new ground on it.

Q. - Thank you. Now the implications of a change in the scope of the project, whether it's because of one of the number of high risk technical issues that you -- we have gone through today following inspections, an assessment at the plant or whether it's regulatory requirements imposed by the Canadian Nuclear Safety Commission, or whether it's problems that just crop up in the process of trying to remove and re-instal the various tubes and these kinds of things over time. There is a potential for running beyond the 18 months that you have allocated for the

refurbishment project, correct?

MR. WHITE: Always potential for that. The best way to avert that potential is understand the risks, do proper planning, get your engineering done early, get all your details done early before you go into implementation. And so those are some of the risk mitigation strategies that we talked about in our presentation.

Q. - Yes. We will get to that in a minute. But if we look at indent 2, that's the Globe & Mail.com --

CHAIRMAN: That's Ident., Mr. Coon.

MR. COON: Ident.

CHAIRMAN: For identification.

MR. COON: Indent. It's getting late in the day.

CHAIRMAN: Can't say as I blame you.

Q. - Ident. I should have written it down. Entitled "Problems Push Back Pickering Re-opening". It starts off by saying, Ontario power generation has experienced unexpected work and design problems that will delay the start of its Pickering A nuclear stations for nine months. And the second sentence -- it goes on -- paragraph -- goes on to say, it's the second major delay in restarting the station, idle since '97, because of financial, safety and environmental concerns.

And the third paragraph mentions that the original

delay was three months. So there was a three month delay and a nine month delay in restarting Pickering according to this.

In my understanding of the work that was done at Pickering here to get these reactors restarted, this was not about retubing the reactors, is that correct?

MR. WHITE: That's correct.

Q. - That had previously been done earlier on?

MR. WHITE: That's correct.

Q. - And this was other work that they had to do at Pickering to bring the reactors back on line. In fact if you go down to the -- first, second, third -- the fourth paragraph from the bottom it says, it requires about 1.3 billion in upgrades to meet current standards. Now in order to -- so we had nine months and three months, so in all a years delay on this work -- on these reactors that had previously already been retubed and this was other work that had to be done to get them into shape and to meet current standards.

As I understand from your evidence in pre-filed A-1 on page 8, you talk about these contracts that -- or you introduce these contracts that have been entered into with AECL to try and minimize the risk of such overruns -- part of the purpose as I understand it is to minimize the risk

of overruns and delays in terms of the schedules, is that correct?

MR. WHITE: We looked at the framework under which we could refurbish Lepreau. And we recognize a couple of things, one is as a small utility in a ever changing environment out there in the nuclear business, we would like to mitigate some of our risks. And secondly, in terms of endeavouring to undertake a project of this nature, there are many white spaces that things can fall into and therefore we believe that choosing a single contractor, particularly our design contractor for the reactor itself, because all indications from other suppliers are that they would have to engage the designer in order to carry out this work was a prudent strategy. And that putting all the work under one contractor provided the simplest form of management of the composite of work and provided a single oversight view for NB Power to ensure that its aims and purposes were being met.

Q. - Well perhaps we could take a quick look at the two contracts that are relevant here. First the retubing contract, which is exhibit A-13, PNB 9 is were it's found.

MR. DUMONT: It's PNB 9?

MR. COON: PNB 9.

CHAIRMAN: What page?

MR. COON: Right. That's the next part. It would be section 2.41. And specifically 2.41.1, warranty for schedule on liquidated damages.

Q. - Now as I understand this, if AECL does not complete the retubing within the 18 months, that they will pay NB Power's liquidated damages, $250,000 each day of delay. Is that correct? Do I understand that correctly? And what percentage of the costs of those delays would that represent on a daily basis?

MR. WHITE: That's about half of the 500,000 and a third of the 750,000 that we said that an outage of Lepreau typically costs.

Q. - Half to a third?

MR. WHITE: Between a third and a half.

Q. - Would there be other costs involved in delays besides the additional costs in replacement power?

MR. WHITE: Well certainly we will have staff there engaged on the return to service activities that are extended because of those kinds of things. AECL in their own rights under their contracts will have people still there working on the activities in terms of trying to complete the work, so they have costs as well. You have got -- if you have got a delay you obviously have interest during construction that is still building up.

Q. - And you are referring to labour costs in talking about staff being --

MR. WHITE: Yes.

Q. - -- the impact on labour costs? Now that 250,000 a day for each day of delay has a cap as I read this of $10 million, is that --

MR. WHITE: That's correct.

Q. - -- what's that's for? So you could get for every day of delay $250,000 up to 10 million and then after that the money stops, is that correct?

MR. WHITE: It's about 40 days worth.

Q. - 40 days. So basically a portion of the costs resulting from a delay in retubing will be covered off by AECL through this contract up to 40 days worth of delay?

MR. WHITE: That's correct.

Q. - And we just saw in the Pickering example where they are upgrading to meet current standards at the Pickering plant said they are a year overdue. So would -- do you feel this 40 days coverage is a reasonable insurance for the project?

MR. WHITE: The approach that we have taken to this project is really to drive the contracting from the point of view of doing the engineering and the development and the planning work up front before we ever enter into the

project. And that is quite different than what happened in Pickering. The approach to this contract is to in fact drive early completion which would pay AECL the bonuses at the rates that are in the contract. On the next page you will see it's $100,000 a day.

It's in our interest to ensure that the incentives are high for AECL to in fact execute their engineering work well before we ever start this work, and for them to execute the contract early so that they get good bonus payments out of that. They not only increase their profits, but they increase their bonus payments by doing that. And so our incentives of being built on the front end to do the job right, as opposed to being built on the back end if they do the job wrong.

Q. - Are you saying, Mr. White, that your goal is to finish before the date of provisional completion so that you can pay -- what did you call it -- bonuses to AECL --

MR. WHITE: Yes.

Q. - -- of $100,000 a day?

MR. WHITE: Yes.

Q. - Why would you want to do that?

MR. WHITE: Because if we pay them $100,000 based on the replacement costs that we just talked about 750' to 500' to $750,000, we make significant upsides on that and we

shared a little bit of that with AECL as a key inducement to do the work early and Mr. Eagles spoke to us investing in early work that allows us to reduce this schedule by potentially one to two months.

Q. - Okay. So we got 40 days on retube coverage. And that's capped off with that and beyond 40 days we are on our own, we know that.

All right. Now let's look at the refurbishment contract, which is in A-17. I think it was A-17. And on page 62, section 15.3.1 it refers -- now this is for refurbishment, so this is aside from the retubing. These are all the other activities that AECL as outlined in this contract would be responsible for besides retubing. All right.

So in 15.3.1 we say, (c) if the contractor does not achieve the date of provisional completion, the contractor shall pay the owner, that's NB Power, as liquidated damages the amount of $75,000 for each day of delay which is less than in the case of the retubing contract, correct?

MR. WHITE: That's correct.

Q. - $75,000 in this case instead of -- what was it -- $250,000 in the retubing case?

MR. WHITE: That's correct.

Q. - Why the difference? Why would you negotiate much less in the case of delays because of -- in the refurbishment side of things rather than the retubing side?

MR. WHITE: Well again they are negotiated numbers. The two contracts have different overall values. And these were the numbers that we agreed to in the negotiating process. And again from the point of view of the driver to these things, the key to doing these projects and being successful on the projects, is getting the engineering work done early and the planning work done in depth.

And if you do those kinds of things you have high probabilities of being successful. If you don't do those things you are already setting a trap for yourselves. So our focus is much more on the bonuses that we would pay that's in 15.3.2 in terms of getting AECL to come in early and we hope that we are paying those bonuses, because they give us much better returns.

Q. - And this also has a cap on it, $75,000 for each day of delay up to an aggregate maximum of $5 million, which is also a lower cap than the retubing contract considerably. Correct? And that works out to be 66 days pretty much -- 66 and change?

MR. WHITE: I think your math is probably pretty close.

Q. - So we have got 66 days coverage kind of insurance to

contribute to a portion of the overruns because of delays on the refurbishment side, and we have got 40 days on the retubing side. Only the 66 days is for less daily amounts, correct? Okay.

So we have got 40 days and 66 days. And in the Pickering case they were over by 12 months. And I guess I asked you before, but I don't think I got the answer. Well you just said you were aiming for paying AECL bonuses, but in terms of insurance I guess is the way we can think about how -- what these contracts, do they provide some partial insurance anyways for delays whether this insurance coverage is adequate in your view?

MR. WHITE: Well again if you had your desires you would have 100 percent coverage, but you don't usually achieve those kind of things without exorbitant costs. And so you through the process of negotiation come up with what you think is an appropriate incentive to both get the contract done early and an appropriate number as a penalty if the contractor not going on as you had expected. They are never intended to cover loss generation guarantees at a full level.

Q. - On the refurbishment contract, the coverage for replacement power, of course, being less money, $75,000 represents 15 to 25 percent of the replacement power costs

in the event of delays, is that about right?

MR. WHITE: I'm sorry, I didn't catch your number?

Q. - 15 to 25 percent as opposed to the higher -- the --

MR. THOMPSON: 30 to 50 percent.

Q. - -- 30 to 50 percent in the retubing contract?

MR. WHITE: Sorry, I'm not computing what you are saying here.

Q. - Well we had with the retubing contract enough money for up to 40 days to cover off a half to a third of the replacement power costs depending on what those were?

MR. WHITE: Yes.

Q. - And in the refurbishment contract as it's less money, it would seem to be 15 to 25 percent or half the amount of the replacement power costs will be covered?

MR. WHITE: Yes.

Q. - Up to 66 days?

MR. WHITE: Yes.

Q. - Okay. Got you. Very good. I guess, what you are saying just to finish it off, Mr. White, is what you were able to negotiate not ideally what you would have liked to have?

MR. WHITE: Well I think one always likes to have more coverage maybe than what they actually got. But that was the negotiating basis, yes.

Q. - It didn't help to mention that you were buying all this

nice machinery for AECL and in return they could give better contracts? I'm sure you used that.

MR. WHITE: We are buying a service for AECL to do certain things for us.

Q. - Right. Okay. Thank you for that. What sort of delays at Point Lepreau would start to make your business case look a lot less attractive? What is your sort of drop dead delay time that you want to avoid at all costs?

MR. WHITE: Well we looked at four months delay and what the impact of that would be. And that's in response to one of our interrogatories. I think it's one of the JDI ones. And I think the number is around $63 million for four months.

Q. - So you wouldn't want to go there. You want to -- wouldn't want to get to four months?

MR. WHITE: Well that doesn't make this project uneconomic. And in Panel B Mr. Marshall ran some stress cases which he can discuss with you in detail.

Q. - Yes, we will talk about that in penalty. Thank you. Just to clarify, that's four months after the warranty period or does that start from --

MR. WHITE: Four months was analyzed as November, December, January, February of 2007, 2008 which would be a high load period for us.

Q. - So a portion of that would be covered by the warranty in liquidated damages of the contract, a portion of that four months?

MR. WHITE: It's covered by the liquidated damages, that's correct.

Q. - Yes. Correct. Okay.

MR. WHITE: That number represents the replacement power cost. It also represents the IDC that would accumulate during that period of time. And it represents the capacity deficiency that we would have in the wintertime where we would have to firm up capacity requirements. So those three items compute to that $63 million.

Q. - Thank you. Okay. Well, we have pretty well gotten through the questions around the scope of the project and -- and the uncertainty around that.

I would like to move on to some questions about -- Mr. White, around the projected capacity levels for Point Lepreau if it were refurbished. And on page 10 you address this.

Well, we will start with -- I guess, we will start with the history of Point Lepreau and then we will get on to the future. That's back to A-1, Mr. White.

MR. MACNUTT: Give us that reference again?

MR. COON: Sorry, exhibit A-1, page 10 of Mr. White's

evidence.

Q. - So this actually deals with the historical performance of Point Lepreau and then -- and then we will look at projections for the performance of a refurbished Lepreau.

So at the bottom of page 10, Mr. White, you say that Point Lepreau's operating performance faltered beginning in 1995. Is that correct?

MR. WHITE: That's what the statement says, yes.

Q. - Yes. And after -- that was after 12 years of operation of the newly constructed Point Lepreau, isn't that right?

MR. WHITE: That's correct.

Q. - 12 years old. So after 12 years the station's performance began to falter. Now if we go to Mr. Pilkington's evidence on page 3, the same exhibit. Flip over to Mr. Pilkington, page 3 at the top there, the second paragraph.

Mr. Pilkington you say, although it wasn't recognized at the time precursors in declining performance were developing in the organization between 1992 and 1995. In the three year period before it was recognized that performance was starting to falter, is that correct?

MR. PILKINGTON: That is correct.

Q. - So that is to say then the -- to dealing -- precursors in declining performance at Point Lepreau as a new power

plant were developing as early as nine years into the life of that new power plant. Is that correct?

MR. PILKINGTON: That is correct.

Q. - And what was the engineered operating life for Point Lepreau? What was planned for?

MR. PILKINGTON: It was originally planned for 31 years.

Q. - 31 years. Problems began in nine years, or at least developed as early as nine years, okay. And the 31 years was planned for what capacity factor?

MR. PILKINGTON: That was planned for 80 percent capacity factor.

Q. - Over the 31 years.

MR. WHITE: Mr. Coon, just to be correct the original design is 80 percent at 30 years. The additional year comes because of the SLAR outage, so that's why Mr. Pilkington had referred to 31.

Q. - Thank you. Okay. So we can talk -- 80 percent at 30 years is a fair way to talk about it. Okay.

And now, I'm afraid, Mr. Pilkington, we are going to have leave you here because I want to ask what the plant operating life of the reconstructed Point Lepreau would be, and I guess that's Mr. White or Mr. Eagles, is it? Or you can answer if you like.

MR. WHITE: Yes, we are going for a 25 year extension from

2008 to 2032.

Q. - 25 years. And the planned capacity factor over that 25 year period, just to refresh my memory, was?

MR. PILKINGTON: 89 percent.

Q. - 89 percent, 25 years. Okay. And when we reach 2006 and Point Lepreau has to -- has to shutdown, my math tells me it would be 23 years old, is that right?

MR. PILKINGTON: That's correct.

Q. - So Point Lepreau is going to shutdown after 23 years of operation and we are proposing to operate a refurbished Lepreau for 25 years, two more than we got out of Point Lepreau?

MR. WHITE: The current life is based on the pressure tubes as per our earlier slides. And Mr. Groom explained the changes in the metallurgy and the manufacturing and the issues with pressure tubes and the spacers. So normally these pressure tubes are designed on the nominal basis of 30 years at 80 percent capacity factor, so targeting a 25 to 30 year life on these replacement pressure tubes is technically appropriate.

Q. - Now of course, the performance in the capacity factor in the -- in the life span of a refurbished reactor is critical to -- to its -- to its economics. Is that correct, Mr. Pilkington?

MR. PILKINGTON: Yes, it is important.

Q. - On page 21, Mr. Pilkington, of your evidence -- I'm not leaving you, there is a table, table 2. It has got two things in it, projected operating costs and capacity factor. But at this moment I want to look at the capacity factor. It's presented on an annual basis. And we will start at 2008, of course, where a refurbished Point Lepreau could kick in.

Now if we look 12 years into the operating life of the reconstructed Point Lepreau, which would take us to 2020, we don't see any particularly dramatic reduction in capacity factor. You are saying 86.7 percent there. Well, actually that's -- that's an anomaly, isn't it, a little bit. Let's skip to the next year, say 96.3 percent -- well, no, 86 -- we will stick with 86.7. 86.7 percent in 2020 is also what is projected in 2012 and with no decline.

Now given the operating experience at Point Lepreau why wouldn't we see some reduction in the capacity factor 12 or 13 years into a reconstructed Point Lepreau?

MR. PILKINGTON: Well there is really a couple of reasons. First of all, you have picked a number very close to the break point. If you use -- look at the years that follow, you will see that there is a slightly greater reduction in

capacity factor in the outage years to account for the aging plant.

But if you look at a comparison between the current Point Lepreau and the refurbished Point Lepreau there is really two key differences, one, is that we will have eliminated the design problem which has cost us significant production. And that being the correction of problems with fuel channels and feeders.

I said earlier that if one discounts the fuel channels and feeders, then the capacity factor at Point Lepreau to date is about 88.1 percent. So that has been a huge contributor to lost production at Point Lepreau.

The second thing is -- and again I brought it up in my presentation. In fact, you referred to precursors to declining performance. In that -- with Point Lepreau when we went through 10 years plus, a very strong performance. In fact being for a lot of that time number one in the world for production.

We did not adequately anticipate plant aging. And we did not put programs in place to address that. In fact we were in a period of declining budgets when we, in fact, should have been increasing spending. We have learned a lot from that. And as I mention in my presentation, we would move towards continuous improvement mode of

operation where we will, in fact, be making improvements as the station operates. And so we will not again get into this cycle of declining performance and requiring -- well, resulting in reduced capacity factors and requiring an improvement program.

Q. - Now just to understand this table, every second year out you have got 96.2 or 96.3 percent capacity factor basically constant through to the end of the projected life of a refurbished Point Lepreau. And so on those off years you are not projecting any decline in performance. In other words, any unplanned shutdowns?

MR. PILKINGTON: Well we in fact have put in contingencies for some unplanned outages. I, again, refer back to the presentation where we have put in 3.5 days each year and 10 days in the years that we have not scheduled a maintenance outage.

Q. - Yes. Thank you for clarifying that. So right through from day one to the end here, for years where there is no maintenance outage you have got 3.5 days for unplanned shutdowns at the plant?

MR. PILKINGTON: Plus 10, 13.5 days.

Q. - Plus 10 in the same year?

MR. PILKINGTON: Yes. Let me just -- let me just clarify.

Q. - That would be good.

MR. PILKINGTON: In every year whether there is a shutdown or not, there is a contingency of 3.5 days. In those years which do not -- the alternate years when there is no maintenance outage scheduled, there is an additional

contingency of 10 days.

Q. - Okay. So the years that you have got maintenance outage planned, you have got three and a half days per year budgeted for unplanned outages?

MR. PILKINGTON: That is correct. Now not to confuse the issue, but in all of those years when we have outages planned, we have also provided a contingency of 50 percent of the outage duration.

Q. - I was almost with you. When -- in the years where you have got planned outages what I heard you say was you have got 13.5 days unplanned for those years?

MR. PILKINGTON: Okay. Let me -- let me try one more time.

Q. - One more time.

MR. PILKINGTON: In a year when we have scheduled an outage we have provided a contingency of 50 percent of the outage duration. For instance, in the early years our outages are generally planned for 30 days every two years. So in an outage year where we plan 30 days, we would have a contingency on outage time of 15 days.

Q. - I got you.

MR. PILKINGTON: Okay. Now in an outage year we would also have a contingency of 3.5 days for a forced outage.

Q. - So it's 50 percent plus the 3.5 days?

MR. PILKINGTON: Right.

Q. - Got ya. Okay.

MR. PILKINGTON: Yes. If that's not clear, we have from the slide presentation there was one slide specifically devoted to this.

Q. - Yes. Well you could refer to it. Because it was a little unclear when that came up.

MR. PILKINGTON: Okay. It was slide number 83.

Q. - This is in A-16, I think --

MR. PILKINGTON: That's correct. Well just to point out the contents, first of all that the outages are every second year. And that in the first 13 years --

Q. - I lost it, sorry. Which slide number?

MR. PILKINGTON: 83.

Q. - Okay.

MR. PILKINGTON: Okay. First of all, outages will occur on the 24-month cycle. So every second year. That in the first 13 years of operation post-refurbishment, the outages are scheduled for 30 days with a 50 percent contingency on top of that. So we have allowed in fact 45

days.

And then in the years following to end of life, the outages are scheduled for 50 days again with a 50 percent contingency. So in fact they are scheduled as 75 days.

And on top of that, in every year of operation there is 3.5 days allowed for forced outage. And in alternate years with no planned outage, there is an additional 10 days allowed for forced outages or equivalent derate. And I might just point --

Q. - In the non-outage years you have got 3.5 days per year plus the 10 days. So it is like --

MR. PILKINGTON: That is correct.

Q. - -- 3.5 --

A. Yes.

Q. - -- for the non-outage years? All right. That is clear. Thank you, Mr. Pilkington.

Now my question on this was then in the non-outage years however, we don't see any increase in the planned outage -- forced plan, budgeted forced outages or unplanned outages in the years where you haven't got planned outages.

I feel like I'm talking in circles. But I think you get my drift here. The years where you haven't planned a shutdown for maintenance or what have you, you are not

increasing the budgeted years for unplanned outages over time?

MR. PILKINGTON: That is correct. And if we manage aging issues then we should not need to.

Q. - Okay. So you are accounting in a sense for aging issues in the years that -- every two years when you are shut down for maintenance, after 13 years of operation, increasing your planned outage, and therefore automatically increasing your budgeted unplanned outage, because it is a 50 percent portion of that.

But in the years where you are not planning an outage for maintenance purposes, you have maintained or are assuming a constant rate of outage or budgeted for a constant rate of unplanned outage over that time, over the 25 years?

MR. PILKINGTON: That is correct.

Q. - Okay. So untoward or unanticipated is budgeted for beyond the 13 1/2 days a year in those off-years?

MR. PILKINGTON: That is essentially correct.

Q. - I'm glad you said that. Okay. I'm sorry. Did you have something else you wanted to add?

MR. PILKINGTON: I would merely point out that the contingency time that is built in has been built in as an outage extension. That is not to say that it has to occur

that way.

Q. - I understand.

MR. PILKINGTON: If in year 27 there was an unexpected failure, then the contingency time could be applied to that. We had to put in some pattern for planning purposes.

Q. - Okay. Thank you. Well, now this gets to the nub of the matter here. And while we have these slides out, you are saying that one of the reasons for budgeting this way instead of basing your budgeting for unplanned outages on the experience today with Point Lepreau is the changes that will be made if the nuclear reactor is rebuilt in the refurbishment process.

And in those changes that would be different, a number of things in the slides were outlined. If I can find the right slide. Here it is. Okay.

So in exhibit A-16, the slide deck, slide 58 there is a --

MR. PILKINGTON: Okay. Got it.

Q. - -- design, manufacture and installation enhancement. So these are the things that are listed here, which you are assuming will ensure that we don't have a repeat performance of the experience with Point Lepreau this time?

MR. GROOM: Yes. These are the features that we have put into the fuel channel assemblies.

Q. - But the argument was made that well, if it is refurbished or rebuilt that the experience will be very different in terms of performance, because you won't be subject to the same problems such as actual growth in the pressure tubes and sagging and these things that you -- and corrosion in the feeder tubes, these problems that you outlined with Point Lepreau?

MR. PILKINGTON: We will not have loss of production similar to what we have had in this time around. We will not have these losses of production due to problems with fuel channels and feeders.

Q. - But would you still expect some of the same phenomena that led to that loss of production? In other words, in a reconstructed Lepreau would you get I think what you call axial creep or lengthening of pressure tubes?

MR. PILKINGTON: Yes.

Q. - It would still occur? And would you get sagging in the pressure tubes?

MR. PILKINGTON: Yes.

Q. - Okay. So you get axial creep. You get sagging. But you are going to avoid that causing downtime?

MR. PILKINGTON: We haven't lost any production time due to

elongation of fuel channels or due to sag of fuel channels.

Our loss of production has been due to movement of garter springs between the fuel channel and the Calandria tube, between the pressure tube and Calandria tube.

Q. - But what you have lost is seven years off the life of Point Lepreau, correct?

MR. PILKINGTON: Yes.

Q. - Because of those problems, axial creep and sagging and the feeder pipe corrosion?

MR. PILKINGTON: I'm sorry. I was speaking about the loss of production with the plant in service. You are correct that aging mechanisms have also reduced the total duration of the life of the plant.

Q. - Okay. So we have got these two issues. Will the aging mechanisms be therefore operative in a reconstructed Point Lepreau?

MR. PILKINGTON: I would pass that to a metallurgist.

MR. WHITE: Just before he moves there, just to be clear, seven years is a calendar time.

Q. - Yes.

MR. WHITE: But what is actually calculated is 30 years at an 80 percent capacity factor. As we reported, we are running at 83.6. So you don't get 30 years if you are

running above 80. You have less time than that.

So we are probably six years or so instead of seven that you --

Q. - Six?

MR. WHITE: -- referred to.

Q. - Thank you, Mr. White.

So yes, the question on the aging is why are we assuming we are going to get 25 years out of a reconstructed Point Lepreau given the same aging problems would occur here?

MR. GROOM: Well, I guess twofold. I think I made mention in my presentation yesterday that we do have operating experience with these new design features in operating reactors.

Two of the tubes that have been put in at Point Lepreau, one of which has been run since 1989, has the features of the tight fit garter spring. So we know that it behaves in the way that Mr. Pilkington has described.

We have good information about its creep growth performance and its sag, and are confident that it is capable of delivering the 30-year, 80 percent capacity factor target.

Q. - Sorry. What did you say?

MR. GROOM: Bearing in mind our design we set here is 25

years, we are confident we can exceed 25 years.

Q. - I'm sorry. What year did you say that pressure tube was installed?

MR. GROOM: 1989.

Q. - 1989. So that would mean it has had calendar years, what, 11, 12, 13 years -- 13 years?

MR. GROOM: Yes. But of course we can compare the first 13 years on this pressure tube with the first 13 years on its neighbours and on the basis of that begin to see the performance improvements.

Q. - Right. And it was about 12 years or so into the life of Point Lepreau when these kinds of problems first started to -- no, I guess that is performance, wasn't it, you were talking about? Let's not confuse the two.

MR. GROOM: Well, these performance features we have been measuring at Point Lepreau since it started up in 1983. For example, the issue on elongation is something we have been measuring.

So it is part of our routine monitoring on all the fuel channel performances to collect this data and monitor for any evidences of changes from the predicted design features.

Q. - So 13 years in with the single pressure tube, you are feeling confident with how it is performing so far?

MR. GROOM: Yes.

Q. - Now is this design the same as what is going into the Chinese reactor which is mentioned here?

MR. GROOM: There are some additional features that have been incorporated beyond that which was put in at Point Lepreau in 1989.

For example the procedure for controlling the metallurgy of the Zirconium material has been improved. These higher impurity features give better in-service performance, better resistance to creep growth effects.

We have also improved our hydrogen controls so there is less hydrogen pickup. These all buy extra margins against the kinds of problems we are currently seeing at Point Lepreau.

Q. - And the design going into the Chinese reactor, have these pressure tubes had any operating experience yet in Canadian reactors?

MR. GROOM: Well, the answer is yes. As I mentioned, for example, the feature of the tight fit garter spring has been in Point Lepreau since 1989. It has been in the Pickering reactors, in the Pickering-A units that were retubed since about 1983, '84.

Q. - I only asked because you said that this wasn't exactly the same. This was -- there were different features to

this particular design?

MR. GROOM: There are some new enhancements that have been built into the China reactors, which we think will give us additional margins, as I mentioned before.

Q. - Okay. So there are some enhanced design factors or whatever for the Chinese reactor. And you are going to adopt that for Point Lepreau?

MR. GROOM: That is affirmative.

Q. - But these enhanced factors, the design features have not been -- had any operating experience as it were, at this point?

MR. GROOM: Well, the answer I gave you is yes, most of them have. There are several here. So you would need to be specific to ask me which one is or which one isn't before I could answer directly.

Q. - Okay. Now you mentioned the experience -- sorry, if we move to slide 59 -- experience of tight fit spacers with small coil diameters.

And I'm assuming that this is designed to deal with the problem of moving around garter springs that you mentioned to us previously?

MR. GROOM: That is correct. Yes.

Q. - And so there has been some experience with that. Now what about with the seamless Calandria tube design has

there been operating experience with that?

MR. GROOM: The Calandria tube, of course, that we currently have is seamless through 390 degrees of its circumference. It has a small area of about 10 degrees where we currently have a weld bead down the center of the current design.

With the new design we are going to remove that so that the full tube will behave like the balancing tube. So we think we have a lot of experience at how well the seamless tube will behave in-service.

There have been operating tests done to demonstrate that this new design has higher strength. And higher strength is one of the features we are looking for in the long term.

Q. - But this new design will be the first time for an in-service reactor?

MR. GROOM: It will be the first time in an in-service reactor, yes.

Q. - Okay. Thank you. I just missed one on the pressure tubes, you asked about specifics. This new rolled joint design on the pressure tube, again is that something that's unique to the Chinese tube that is going to be used at Lepreau or is that something its had in service?

MR. GROOM: I'm sorry, David, would you repeat the question again?

Q. - Yes. It was back on slide 58. I meant to ask you about the new rolled joint design --

MR. GROOM: Yes.

Q. - -- for pressure tubes, and whether or not that was something -- well it says new, therefore I'm assuming that it will be new for at least a Chinese reactor in Point Lepreau?

MR. GROOM: The new -- all of the replacement pressure tubes that have been put in at Point Lepreau adopt this new rolled joint design and the replacement tubes would -- putting in for single channel events and all the other reactors incorporate that as well. And the feature about it is really the amount of roll expansion that takes place on the connection between the pressure tube and the end fitting.

Q. - Thank you. Now can you -- can we change to exhibit A-5, please. Those are the supplementaries -- some of the supplementaries, CCNB 12.

CHAIRMAN: It's not a supplemental, is it, Mr. Coon?

MR. COON: You are right. Thank you. It's just a plain old interrogatory, CCNB 12.

MR. DUMONT: What part are you referring to?

MR. COON: CCNB 12, page 70.

MR. DUMONT: Thank you.

Q. - Mr. White, in your response here you say that there have been no CANDU stations life extended beyond their original design life, which I guess just confirms what you had answered earlier in response to cross examination.

If we flip over to 13, we asked if you could address the issue of whether refurbishment projects similar to that of Point Lepreau have been done elsewhere. Because in your evidence relate to American experience and various things. And there you say refurbishment projects similar to the proposed for Point Lepreau have not been conducted elsewhere due to the unique design features of CANDU reactors. So that's correct?

MR. WHITE: Yes. As Mr. Groom explained, the key design feature of the CANDU reactor allows for removal and replacement of pressure tubes and Calandria tubes so that in fact it can be life extended. And so the original design for 80 percent for 30 years recognized that the pressure tubes would run out of their metallurgical life but could be replaced if the owner/operator chose to replace them and extend the design life at that time.

Q. - So with respect to the projections about 25 year life span for reconstruct at Point Lepreau operating at 89 percent capacity factor, you are therefore not drawing on experience from other reactors that have been refurbished

because you said that hasn't happened in a relevant way before in terms of life extension, is that correct?

MR. WHITE: A CANDU reactor has not been life extended at this time. As example in Britain, and of course it's an altogether different design, Calder Hall is running over 45 years now. So it's not any direct comparison but there are reactors that have long lives on them.

Q. - Correct. But you can't make a direct comparison because the CANDU unit is unique, is that correct?

MR. WHITE: Well as you pointed out quite accurately, we are at the leading edge with the most number of hours on an operating CANDU reactor, and therefore none have been extended beyond that at this stage.

Q. - So in -- you can turn to CUSJ 2 in this book. CUSJ 2, interrogatory. That's the very front. Okay. Got it? And am I correct -- in reviewing this table that summarizes capacity factors for all nuclear power plants in Canada, am I correct that not one of these reactors the first time through here has achieved an 89 capacity factor?

MR. GROOM: That is correct.

Q. - Correct. Even Darlington, which is the most recently built CANDU reactor in Canada in 1993, I guess units 3 and 4 failed to get out of the low 80 percent capacity factor in its first nine years of operation, is that correct?

MR. PILKINGTON: That is correct, and the I guess performance of Darlington has not followed the same pattern as other units, like Point Lepreau. Darlington had some design problems early and as a result their operating performance was poor in the early years.

We don't have the information here but one of the CANDU units of our vintage, being Quinshan, does have long-term high capacity factor. They also had some difficulties in their early years but since then have operated at continuous high capacity factors.

Q. - So none of these reactors have come close to 89 percent but you are assuming a reconstructed Point Lepreau would achieve 89 percent over its 25 year life?

MR. PILKINGTON: Well in fact most of the reactors listed here have had significantly long periods of capacity factors in the 85 to 90 percent range. By giving the capacity factors to date we are bringing in periods of poor operation as well.

Just to add on Quinshan, Quinshan unit 1 has had an 85 percent capacity factor since it went into service in 1983 and it also had some early life design difficulties that reduced the capacity factor in the early years.

Q. - But we are not going to have any difficulties at a reconstructed Point Lepreau, that's the plan.

MR. PILKINGTON: Well the wonderful thing about a reconstructed Point Lepreau is that in fact it went through its initial teething problems, and actually in the case of Lepreau there really weren't any significant ones. So we have a lot of operating experience on the plant as a whole.

We do have in recent years a lot of lost production as a result of fuel channel and feeder problems, but correcting those will allow us to operate at high capacity.

Q. - Can I just clarify this now. My understanding was the fuel channel and feeder problems was resulting in premature aging and meant we were losing effectively six years off the life at Point Lepreau, according to Mr. White. But now you are saying it's also contributed to down time. Can you explain?

MR. PILKINGTON: Absolutely. For instance in 1995 we took a six month-plus shut-down to do SLAR to initially move garter springs back to the design locations, and in essentially every year since then we have put a significant amount of the plant outage time into repositioning garter springs and taking measurements on fuel channels and feeders.

Q. - Now if we can go to CCNB 26 in the same volume, on page

83 --

MR. SOLLOWS: 25 or 26?

MR. COON: 26. March 25th I guess, page 85.

Q. - There is a table here, Pickering A annual capacity factors following retube. There are four units as I understand it at Pickering, four separate stations or plants.

And if we look at unit 1 following a retubing -- now I realize this is just retubing and it's not also -- doesn't -- didn't involve removal of the Calandria tubes but just the pressure tubes -- in -- but at considerable cost. That plant only operated for 10 years and it's capacity factor was 65 percent on average.

If we look at P-2, the second unit there, after it was retubed it operated well for nine years but also had a capacity factor of 65 percent. Unit 3 operated for seven years at a capacity factor of 63 percent. And unit 4 only operated at four years after being retubed at a capacity factor of 62 percent.

And as we saw in Ident. 2 those plants are still off-line waiting to get through their process to come back on line and are facing further delays to do so.

So my question is why here in the case where we had complete retubing of these four reactors did we get 10

years and less of operating life out of them thus far and capacity factors of 65 percent or less?

MR. PILKINGTON: Yes. First of all my first comment would be that the actual retubing of those reactors was successful. It's not relevant that they didn't change Calandria tubes, at least not in the short term.

And the fuel channels that they installed have had excellent performance ever since.

So where at Lepreau a significant amount of our loss capacity has been due to problems with fuel channels and feeders, since the retubes were done at Pickering they haven't lost significant capacity as a result of problems with fuel channels.

However, they have suffered the same kinds of operating problems as Point Lepreau in that they have not dealt with other aging issues. They in fact didn't do a broad refurbishment of the plant. And so they have suffered from other equipment problems and they have suffered from the kinds of human performance and process problems that we have also experienced at Lepreau.

Q. - So what you are saying, Mr. Pilkington, as I understand it is you would want to ensure the scope of a refurbishment or reconstruction project will be as broad as possible to replace as much of the old equipment as

possible to try and hedge your bets to ensure that you can achieve the highest possible capacity factor after coming back?

MR. PILKINGTON: Well it's not a case of replacing as much as possible. It's a case of doing a good assessment on what needs to be replaced, where the aging issues are with the equipment, and replacing all of the equipment that potentially could cause performance problems into the future.

Q. - Some of which as we heard earlier won't be known until you can actually look inside the reactor vessel and the thing is down and the fuel channels are out so you can have a peak?

MR. PILKINGTON: That actually applies to very few components. The vast majority of plant has been covered by the condition assessments that were done in Phase 1 of refurbishment, and by inspections that have already been carried out in the plant.

Q. - Yes, that's true. There was a few that were identified as having a high risk, high cost if they had to be replaced I think.

So then you are confident that these kinds of problems that arose at Pickering will be avoided by NB Power doing a much more thorough job than Ontario Hydro did at the

time?

MR. PILKINGTON: Well the problems that have occurred at Pickering will be avoided and they will be avoided by a broader assessment of the equipment that needs to be refurbished, and by the improvement programs that I talked about that will be ongoing up to the refurbishment outage at Lepreau, that being improvements in human performance, equipment performance and work processes.

MR. COON: Thank you.

CHAIRMAN: It's five to 5:00, is this a good spot for us to break for the evening?

MR. COON: It would be as good as any, Mr. Chairman.

CHAIRMAN: All right. We will reconvene tomorrow morning at 9:30.

(Adjourned)

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

Reporter

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