(9:32 a.m.)

CHAIRPERSON:

Q. Good morning, ladies and gentlemen. I think as Jim Furlong at NTV would say, it seems like only yesterday, you know. This hearing of the Public Utilities Board is convened this morning in the matter of an application by Newfoundland Power for approval of its 2004 Capital Budget, as well as application for an order of the Board for the purpose of fixing and determining Newfoundland Power's average rate base for the year 2002.

For the purpose of the record, at this time I'll introduce the panel. My name is William Finn and I have been delegated to chair this particular panel. Sitting with me, to my right is Commissioner Gerard Martin and to my left, Commissioner Don Powell. The Board will be assisted by several staff members throughout the hearing. To my immediate left is Ms. Cheryl Blundon, Board Secretary, Ms. Dwanda Newman, Board Solicitor, and Mr. Mark Kennedy, who will act as Board Hearing Counsel. I'd like to ask Ms. Newman, at this time, if she would indicate and

confirm, for the record, all appropriate matters preliminary to the commencement of the hearing, please.

MS. NEWMAN:

Q. Yes, good morning, Chair and Commissioners and other people in the room. I can confirm that an application was received on July 25th, 2003 from Newfoundland Power for, as you said, approval of their Capital Budget and their rate base. This application was amended on September 5th, 2003. They did also file some pre-filed evidence and several revisions were filed to that evidence late, I believe, as even this morning.

I can confirm that the Board published notice of the application and also this hearing date on its website first on August 1st and in several local papers on August 5th. The papers that it was published in include The Evening Telegram, The Western Star, The Shoreline, The Express, The Compass, The Packet, The Southern Gazette, The Beacon, The Pilot, The Advertiser, The Nor'wester, The Coaster, The Humber Log, The Georgian, The Gulf News, The Labradorian, The Charter and

The Northern Pen. I can therefore confirm for the Panel and those in the room that this matter is duly constituted.

We did receive, we being the Board, did receive an intervention from one party, which is Newfoundland and Labrador Hydro, and no other interventions were received. The Board did not receive any letters of comment, did not receive any requests to make oral presentations. There was some requests for information issued and I understand that they have all now been answered by the utility, so that matter is finished. The Board did not require electronic filing in this matter and therefore we will not be having our electronic system operating the length of this proceeding, although I do understand that the monitors will be in use this morning for a short presentation.

The sitting times for this hearing that I propose are from 9:00 a.m. to 1:30, note this morning, being the first day, we didn't start until 9:30, but tomorrow morning will be a 9:00 a.m. start proceeding until 1:30, with a half an hour break from 11 to 11:30. I

MS. NEWMAN:

understand the parties are willing to sit late on any day, if it is deemed to be appropriate in the circumstances, and that's fine with the Board.

Also, I would note that these matters are being transcribed, recorded and transcribed and as per the usual course of events, I believe that the transcripts will be available electronically in the evening of the day of the proceeding and in hard copy the next morning. Of course, if we sit late, then that might impact upon the schedule, but I have ultimate faith that the transcriber will do their best to get it to us as soon as possible, in the event that we do sit late.

I should also note that there's been one information request filed by the Board, and that is a letter from Grant Thornton, and that's Information Number 1. I have also circulated rules of procedure that I propose be used and respected in this proceeding, in addition to those set out in the Regulations 39 96. The rules were circulated by the parties, to the parties and I understand that

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they are in agreement with the same and I therefore propose that the Board adopt those rules in this proceeding.

Finally, I understand that Newfoundland Power does have one matter, one procedural matter that they want to address in terms of a filing, before we start here this morning.

CHAIRPERSON:

Q. Thank you. The Board will adopt the rules as circulated and perhaps at this time, I would ask the parties to introduce themselves, beginning with the applicant.

MR. MYLES:

Q. Good morning, Chairman Finn, Commissioner Powell, Commissioner Martin. My name is Brock Myles and beside me is Gerard Hayes. We are counsel to Newfoundland Power on its application before the Board today. I have an opening statement and I'll proceed with that.

There are two parts to the application, the first seeking the Board's approval, pursuant to Section 41 of The Public Utilities Act, of Newfoundland Power's 2004 Capital Budget of $53,909,000. The second part of the application, pursuant to Section 78 of The

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Act, asks the Board to fix and determine Newfoundland Power's average rate base for the year 2002 at $573,337,000.

As noted, the record of the application commenced with the initial four volumes, which were filed with the Board in July. Volume 1 contains the application itself, including four supporting schedules. Schedule A provides a summary of the 2004 Capital Budget. Schedule B contains a breakdown of the Budget categories and the projects in each category, as well as individual project descriptions. Schedule C sets out those projects for which there is a committed carryover into future years, of which, in fact, there's only one, which is the final payment in 2005 for the purchase of the Aliant poles. Schedule D sets out the calculation of Newfoundland Power's average rate base for the year 2002, which the Company is requesting the Board to fix and determine. To assist the Board, Schedule D also sets out the calculation of Newfoundland Power's average rate base for the year 2001, which was fixed and determined by the Board pursuant to Order No. P.U.36 (2002/2003).

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Volume 1 of the materials also contains four reports that Newfoundland Power was required to file with this application, pursuant to either of Order No. P.U.36 (2002/2003) or Order No. P.U.19 (2003). I'll just review those reports quickly.

The first is the 2003 Capital Expenditures Status Report. Now, Ms. Newman advised you there is an Exhibit. It is a update of the variances shown from May 31st, 2003 to July 31st, 2003, and Mr. Delaney will be speaking to the updated information, as well as the Status Report itself, and I would propose that this updated variance be entered as Exhibit PJD-1.

The second report in the information is the Information Technology Strategy Report 2004-2008, and the second panel, comprised of Mr. Mulcahy and Mr. Collins, will address this report. The third report is the 2004 Capital Budget Plan and it will be addressed by Mr. Ludlow.

Finally, the fourth report is the Changes and Deferred Charges 2003-2004, which was ordered to be filed by the Board with this

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MS. NEWMAN:

Capital Budget application in Order P.U. 19 (2003) which was the General Rate Order, and this report will be addressed by Mr. Perry.

Also contained in Volume 1 is pre-filed testimony of the three witness panels.

Volumes 2, 3, 4 contain supporting material for certain of the Capital Budget projects, being comprised largely of more detailed descriptions and reports. And then, as noted this morning, in addition to the material filed with the application and the subsequent revisions, there have been approximately 282 requests for information filed and responded to, and of course, the RFIs and responses will form a part of the record.

With respect to the witnesses, the pre-filed testimony in support of today's application has been provided by three panels of witnesses who are here today and who will be examined in chief by myself and then be available for cross-examination by other counsel and, of course, by the Board. Mr. Ludlow, Mr. Earl Ludlow and Mr. Phonse Delaney

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will address the 2004 Capital Budget, with the exception of the Information Systems category. Mr. Ludlow and Mr. Delaney will also address the 2003 Capital Expenditure Status Report and the Capital Budget Plan.

The second panel is Mr. Michael Mulcahy and Mr. Peter Collins, who will address the Information Systems projects in the 2004 Capital Budget, as well as the IT Strategy Report and the results of the Customer Service Replacement Study, including the issue relating to open BNS operating systems, which have been previously identified to this Board.

The third and final panel is comprised of Mr. Barry Perry and Ms. Lisa Hutchens, who will address the 2004 Average Rate Base, the Changes and Deferred Charges Report and the matter of financing the proposed capital expenditures.

Mr. Chairman, as well, I'd like to introduce to you Ms. Colleen Comden, who will be running our system during Mr. Ludlow and Mr. Delaney's presentation. However, we have the entire record on electronic copy, and so we would be in a position to refer to the

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documents as we go, if that's--we are actually, in fact, planning on doing that, so if that's acceptable to the Board, Ms. Comden will be available to move to the documents as they are referred to.

CHAIRPERSON:

Q. That's fine, certainly.

MR. MYLES:

Q. Mr. Chairman, unless you or either of the Commissioners have any questions, the first panel is now prepared to commence their examination-in-chief, which includes, as it has in the past, the Power Point presentation.

CHAIRPERSON:

Q. Thank you. Perhaps, for the record, I'll ask initially counsel for Hydro to introduce himself, for the record.

MR. YOUNG:

Q. Thank you, Mr. Chair, members of the Board. My name is Geoff Young. I'm counsel for the intervenor, Newfoundland and Labrador Hydro. Mr. Chairman, it may be--I have a brief opening statement also. This may be as soon a time as any.

CHAIRPERSON:

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Q. Certainly.

MR. YOUNG:

Q. Like Hydro's intervention in Newfoundland Power's 2003 Capital Budget hearing, our intervention in the present matter is largely driven by and directed to issues of policy and procedure regarding the regulation of the capital budgets of public utilities by this Board. The Order of this Board arising from last year's hearing, P.U. No. 36 (2002/2003), contained a Schedule C, which set out the conditions for future filings to be adhered to by Newfoundland Power. The same conditions apply to Hydro and decisions and Board policies that are made or formed in the regulation of Newfoundland Power's Capital Budget can be expected to have an effect upon the regulation of Hydro and its own Capital Budget process.

In this matter, Hydro is asked 89 information requests and will be conducting cross-examination of some of Newfoundland Power's witnesses, probably not all of them. Hydro will not be calling any direct evidence. The cross-examination, though intended

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MR. YOUNG:

primarily to deal with issues of regulatory policy, as opposed to challenging the prudence or the appropriateness of specific projects, will inevitably deal with the details of the application and supporting documentation, because, in our view, it is not terribly useful to deal with these matters totally in the abstract. It is hoped that the questions that Hydro raised in the request for information and it will raise in cross-examination will illuminate some of the issues referred to before and that the facts that arise in the present matter will come forward and will be of assistance to the Board. Thank you.

CHAIRPERSON:

Q. Fine. Thank you, Mr. Young. Mr. Myles.

MR. MYLES:

Q. Thank you, Mr. Chairman. Mr. Ludlow, are you a professional engineer and vice-president of engineering and operations with Newfoundland Power?

MR. LUDLOW:

A. Yes, I am.

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Q. I'm sorry, it just struck me, the witnesses need to be sworn.
CHAIRPERSON:
Q. Good thing somebody's thinking.
MR. EARL LUDLOW, SWORN
MR. PHONSE DELANEY, SWORN
CHAIRPERSON:
Q. Mr. Myles.
MR. MYLES:
Q. Thank you, Mr. Chairman. Mr. Ludlow, are you a professional engineer and vice-president of engineering and operations with Newfoundland Power?
MR. LUDLOW:
A. Yes, I am.
Q. And you have prepared pre-filed testimony in the exhibits. Do you adopt these as part of your sworn testimony today?
A. Yes, I do.
Q. Mr. Delaney, are you a professional engineer and manager of the western region with Newfoundland Power?
(9:47 a.m.)
MR. DELANEY:
A. Yes, I am.

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Q. And you have prepared pre-filed testimony in the exhibits. Do you adopt these as part of your sworn testimony today?
MR. DELANEY:
A. Yes, I do.
Q. Mr. Ludlow, what will be your focus today?
MR. LUDLOW:
A. Good morning, Mr. Chairman and fellow Commissioners. Today, I propose to use, as counsel suggested earlier, a Power Point presentation to provide the Board with an overview of our 2004 Capital Budget application and the details contained therein. First, I will provide the Board with a high-level general overview of Newfoundland Power and the provincial electrical system. And secondly, I will present the 2004 Capital Plan, and this was filed as part of the application. From there, I will pass along to Mr. Delaney, who will take you through the 2003 Capital Budget Variance and the specifics of the 2004 Capital Budget application. That is, with the exception of the Information Systems section and that will be dealt with by a later panel.

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MR. MYLES:
Q. Mr. Ludlow, in your prepared pre-filed testimony, at pages two to five, you provide a general overview of the 2004 Capital Budget. What highlights do you want to give to the Board today?
MR. LUDLOW:
A. Well, first of all, I'd like to start, and this is a standard chart that I've been using now for probably four or five years, but never hurts to bring it back up, I guess. What I have presented on the screen or in the screen in front of you is the service territory serviced by Newfoundland Power on the island portion of our province. It's important to note that this is clearly representative of a combination of rural and urban customers. As you can see by the orange or brown area on the chart, we service mainly from the southwest coast through the Port au Port up to Corner Brook, parts of the Baie Verte, cross into Central, Grand Falls-Windsor, Twillingate, Bonavista North, Burin, Bonavista Peninsulas and pretty much--well, not pretty much, all of the Avalon Peninsula. The areas not serviced

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MR. LUDLOW:
would include the Great Northern, again parts of the Baie Verte, Fogo Island, and there's a couple of areas not quite clear here and they would include St. Brendan's, Monkstown, and indeed, also on the south coast, the area of the Conaigre Peninsula, as well as, I guess, the areas over as far as Franchois and those areas on the south coast.
Also included on this map is it represents--the dots represent the locations of where we have staff and equipment positioned throughout the province. This is not a--the size of the dot is not indicative of the relative number of staff or crews we have. This would range from St. John's, where we would have by far the bulk of our technical and line, as well as vehicular resources, through to the other extreme, being Baie Verte, where we would have one person and a truck. So each of these basically have been designed and are continually monitored to provide new services, response to trouble, and indeed, what we've tried to do here is to position ourselves to respond to trouble calls

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and the like in a two-hour time frame, and that's the basis upon which we've been operating, and we try to run that consistently across all areas.

Q. Mr. Ludlow, could you please advise the Board what the main drivers are behind the 2004 Capital Budget of $53,900,000?

A. Our capital investments are driven by our commitment to meet customers' expectations for safe, reliable and low-cost electrical service. Therefore, the main drivers for this $53.9 million capital budget are reliability, safety, customer service, productivity and the environment. This is pretty much consistent with the previous capital budgets that I have addressed before this Board. Capital expenditures play a key role, indeed a vital role, in our ability to serve our customers.

Q. Mr. Ludlow, what does this slide show?

A. What you have in front of you here is a slide presenting the entire electrical system at a transmission and a generation level within the island portion of the province, and I use this purely to give a flavour of, I guess, the scope. An electrical system is made up of

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four distinct components. They would be generation, transmission, substations and distribution. Now it's clear, and I bring the Board's attention that this is not representative of Newfoundland Power's system. This is the electrical system. On the island portion, there's Newfoundland and Labrador Hydro who would run the bulk transmitters, as well as the Great Northern and the points I did before, as well as the major generators. We have Abitibi Consolidated and we have Deer Lake Power, and we also have Newfoundland Power, and that's basically a representation of a mix of all these.

The utility industry is very capital intensive. Reliable service requires significant investment in plants. Now put this in perspective. At Newfoundland Power, we have spent approximately one billion dollars to built our electrical system, and to further size this for you, Commissioners, this represents: in excess of 10,000 kilometres of lines, be it transmission or distribution; in excess of a quarter--sorry, quarter million poles, 250,000 poles. We have 137 substations

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within this island and 23 small hydro plants. So that will give you a flavour of the breadth and scope of what we're dealing with here. And that's in place to serve approximately 220,000 customers and they are residing in over 600 communities on the island portion of Newfoundland and Labrador, and that represents approximately 85 percent of the electrical customers, electrical service customers in our province.

Now when you stop and think about the size, the nature and the geography of our system, it is not difficult to understand the continued and ongoing investment that is required to keep this thing running. Combine that with the economics and that the growth is not always uniform across our service territory, we take our obligation to serve our customers very seriously. We must continue to invest in rural Newfoundland, despite the significant out migration that has been spoken at here in the GRA and in other hearings, while at the same time meeting the growth requirements in areas such as St. John's, Northeast Avalon, and also in places like

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MR. LUDLOW:

Corner Brook, and we're seeing some growth in that area now.

Now the quality and condition of the infrastructure on the island is vital for our ability to provide quality service, balanced with the lowest reasonable cost. A sound electrical system is increasingly important in today's technologically dependent economy. It's interesting, twenty odd years ago when I joined the utility, you go to a fish plant and you'd see splitting lines. Today you go, you see microprocessor based conveyor belts. You're seeing microwave thawing of fish product. You can go to the lumber mills, you'd find the same thing, the electronics, and it's that state of technology has ingressed throughout the service territory. That's at that end. You go to medical technology. Today you hear about the MRIs and the dialysis units being brought into more diverse centres than one major centre. It's all dependent. And finally, go to home and business computers. Sustained quality service is vital because today, the home in my

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hometown on Fogo Island, for example, is just as important that it's connected to the world economy, as it would be in downtown St. John's. So hence, it's the reliability that becomes important throughout this presentation.

Q. Could you provide general comments on the 2004 Capital Budget, Mr. Ludlow?

A. Approximately 56 percent or $30 million will be used for replacement and upgrading of older assets within our electrical system. This represents the proactive replacement of deteriorated or inefficient equipment and plant. Keeping in mind, Mr. Commissioners, that the replacement today is much more expensive than the original investment cost, due to inflation. These assets, many of them are thirty to forty years old.

Asecond category of new capital investment, largely for new growth areas, totals approximately 22 percent or $12 million. These are in place, or this allotment is there to add new customers, new services, and also for the addition of load capacity. As the system creeps at one to two

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percent growth, the capacity must be added to carry it.

The third section I'd reference is that of technology investments, representing seven percent or approximately $3.9 million of the budget. This level of investment is needed to support the electrical system and the processes required in the general operation of the business. Technology is also necessary to achieve productivity improvements and to sustain gains made to date in operational efficiency that will ultimately benefit all customers. An investment in technology is at the core of our interaction with our customers and is required to meet their changing level of expectations for flexible and more convenient ways of doing business with us.

Q. Mr. Ludlow, can you refer to the Capital Plan and provide the Board with an overview of the historical capital expenditures at Newfoundland Power?

A. The Capital Plan is contained in Volume 1 of the filing, and if I could draw the Board's attention to the graphic that is contained on page three of the plan and is also

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represented, reproduced here on the screen. We see a representation of the historical capital expenditures from 1988 to present. We took it back to 1988 to give a flavour of--to provide a realistic comparison over the time period. So--figure out how to use this thing now, I got technology. Here we go. So right here, you can see up to around this point, and I'm just flowing through, one thing I'd point to the Board is in the graphic in front of you, as well as on page three, we have shown the Aliant pole purchase separately. You can add them together and get the--you can pick it out in the graphs. That's the--what's the point I'm trying--we've pulled it out and highlighted it separately, I guess.

Since 1988, capital expenditures have ranged from a high of 67 million in 1990 to 29 million in 1996. We can all go back to 1992 when the cod moratorium hit, and that was indeed a time of unprecedented uncertainty in the Newfoundland economy. And if you look here, so we're in this range, for the next four to five years, we were down in the 30 million range, actually it's $32 million was

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MR. LUDLOW:

the average. Since 1997, excluding the Aliant pole purchase, capital expenditures have averaged $47.5 million. Now this is more than the '93 to '97 period, however less than the average of the five-year period prior to the cod moratorium, which was $51 million.

Q. Mr. Ludlow, would you comment on the changes in capital expenditures from 1993 to 2003?

A. Well, the changes in the expenditures from '93 to present were influenced by a number of factors. As I mentioned, the purchase of the Aliant poles, for approximately $41 million over a five-year period, has had an upward effect on capital expenditures. This purchase added approximately $21 million in 2001, $8. million in 2002 and $4 million in 2003. This acquisition of the Aliant poles is justified on the basis of economies of scale and has had the effect of reducing the amount of pole costs that had to be recovered in rates.

(10:02 a.m.)

In 1998, the Rose Blanche hydro plant was constructed at a capital cost of $13. 5 million. Then we have asset replacement has

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accounted for an increasing portion of capital expenditures since 1999, when Newfoundland Power began a focused effort to improve the reliability of its poorest performing feeders, and by feeders, I'm talking about the lower voltage, somewhere between the house voltage to transmission. So that would be in the 2400 to 14,000 volt range. During the period of '93 to '98, between 30 and 46 percent of capital expenditure was for capital, for plant replacement.

Since 1999, greater than 50 percent of capital expenditure has been focused on replacement, and Newfoundland Power has an obligation to serve new customers, that's another block. The customer demand is a direct function of economic conditions. Capital expenditures associated with customer demand declined from '93 to '98, and since 1998, have improved due to improved economy, and expenditures in this category have varied from a low of $5.3 million in 1995 to a high of $12.2 million in 2003. This category would include just the acts of transformers, street lights and tying wires and extensions into the

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housing.

The Information Systems capital expenditures, as a percentage of total, have gradually increased from 1993 to 2003. These expenditures are directed towards improving customer service and indeed, the overall efficiency of our company.

General expenses capital have declined from 1993 to 2003 and this decline flows from Order P.U. 3 ('95/96) that resulted in a decline in GEC from $10 million in '93 to $2.8 million in 2003. Finally, inflation is a factor that has been a key influence on the changes in capital expenditures over the past ten years. Utility assets are long-life assets so replacement costs will tend to be greater than the original costs, and over the past ten years, inflation alone has increased in excess of 20 percent.

Q. Mr. Ludlow, would you please describe the Company's plan for capital expenditures over the next five years?

A. The Company estimates that approximately $260 million will be invested in plant and equipment during the period of 2004 to 2008.

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Expenditures are expected to average $53 million per year and range from 49 million to 56 million. The Company plans to continue its effort to refurbish under performing distribution feeders with respect to the reliability and the safety of those feeders. We will also continue to inspect the balance of our feeders on a five-year cycle and correct resulting deficiencies identified.

In the substation category, the Company plans to continue its effort to replace aged and obsolete reclosers, many of which are at the end of their estimated life right now, as well as relays, and these will be replaced with new multi-function digital units that are remotely controlled from our system control centre. This will modernize our protection and control systems and result in improved productivity and reliability. This plan will also see an increased emphasis on the refurbishment of transmission lines. Many of these lines are older and deteriorated and by that, a lot of that is a direct relationship to age and the winds and weathers of our province. Transmission line expenditures are

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MR. LUDLOW:

expected to grow from 2.3 million in 2004 to an average of $6.2 million from 2005 to 2008.

MR. MYLES:

Q. Mr. Ludlow, there was much discussion on the issue of radial transmission lines during the 2003 Capital Budget application. Can you advise the Board whether the Capital Plan addresses this issue?

A. Again, what I've taken here, Mr. Chairman, is a map of the island, similar to what I used before, and included what we classify as radial transmission systems have been identified in the circled blocks. There's seven of them identified and namely, we have the southwest coast to Port aux Basques. This line is being worked on, I do believe, next June. Hydro and ourselves are working together now on the planning for that process. We move on up to the 138 line feeding the Baie Verte Peninsula. Then we have the Twillingate, which is a single feed out of Gander Bay--Gander Bay, I'm sorry, out of Boyd's Cove area. We have the Gambo to New West Valley area, Bonavista North. We also

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have the Old Perlican, Bay de Verde, Victoria area. We have the Placentia-Argentia back to Whitbourne, 55 L, and finally, we have 94-95 L, which simply transmission line numbers, servicing the area from Blaketown through to St. Catherine's, Riverhead and Trepassey.

Now, I've spoken to this Board on several occasions on these, and simply put, a radial transmission line is a single source of feed for high voltage. You get a generator on one end and you have customers on the other and a long span in between is what it boils down to, sometimes as much as 100 kilometres. We will continue to address these issues of radial lines and that's prevalent throughout this five-year plan. We are concerned about the future performance of these systems, given that these radial transmission lines continue to age and deteriorate and many are exposed to some of the most severe weather conditions. These aren't all the radial systems, by the way. I should make that clear as well. There's some not identified, 5L to Broad Cove is not there. Pulpit Rock out of Virginia Waters, which is Torbay area, is not there.

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So there's some that we have where we're located as short on our reaction time and accessibility would make those what I would call on a much less priority scale than the ones we're dealing with here.

Now the Capital Plan, as presented before this Board, includes projects that will address two of these radial systems, and that being Trepassey, with 94-95 L as I've highlighted, and also the Old Perlican area. In 2004, we plan to purchase a second portable diesel generator and position it in Trepassey. This will not provide complete backup for the Trepassey radial system, but it will provide a greater measure of security for the system in this area.

And what I'm getting to there, Commissioners, is to deal with issues of fire fighting. It can deal with water supplies and those types of basic needs. And we can cover a fair amount of the load with a two and a half megawatt generator in Trepassey. However, that's its stationary point. When it is needed for emergencies elsewhere, it would be also available on the east coast. And also,

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we would use it during construction. And I've spoken to this Board on those types of topics before.

In 2005 we are proposing a project to secure the radial transmission system in the Old Perlican area. Now, this system contains our oldest radial transmission line at 47 years. The Old Perlican project is roughly estimated at 5.1 million dollars. Now, at this point in time the detail is not completed, however, an engineering study will be completed and prepared and presented before this Board at next year's hearing. The Company intends to focus engineering efforts in the future to monitor the reliability performance of these radial systems, and we would plan accordingly.

Q. Mr. Ludlow, again, in the capital plan, if I could refer you to the next page, which would be page 2 of 11, Appendix C of the plan, I note that the capital plan contains several large expenditures in energy supply category. Could you please comment on these?

A. It's interesting, many of our hydro facilities were built pre 1960. And in fact, I don't

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MR. LUDLOW:

know if the average, but by far the majority is greater than 50 years old at this point-in-time. Hydro plant upgrades, particularly penstocks and surge tanks, both of which are presented in this picture. By the way, the surge tank here is in effect a pressure relief valve. In the event that you get a sudden rush of water or the valve closes on the end, it's a place for the water to go. And secondly, this, I'm going to call it a pipe, is, the wooden penstock, this one is in particular in Rattling Brook. These items are very costly in replacement and costs many millions of dollars.

Now, in our plan we have timed these projects keeping in the mind the Board's desire to levelize capital costs over the planning horizon. However, should circumstances change such that the safety or deterioration becomes such a concern, then adjustments may be required and we would have to revisit the plan with this Board.

The large energy supply projects planned include a four million dollar expenditure at

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New Chelsea in the 2004 Application before us here today which we'll describe later. Actually, Mr. Delaney will take you through a lot of that. And there is also a significant expenditure in 2006, you can see the peak in the graph, and that is, in fact, at the Rattling Brook, Norris Arm area. That's a plant we have that the penstock there as well as that surge tank is in need of work.

Q. Mr. Ludlow, what do you think are the major risks in the five year capital plan?

A. There are several risks associated with this plan. One of the first ones would be the area of customer and energy growth. Newfoundland Power has an obligation to serve the customers in our service territory. Should economic factors change such that customer or energy growth varies from our forecast, then so will the capital expenditures have to vary accordingly. We continue to be concerned about the reliability of radial transmission systems. Customers served by radial transmission systems continue to experience more and longer power interruptions than those served by loop systems. And that's the loop

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system basically is a system whereby you have multiple sources of supply. Usually they would be in highly populated areas, St. John's or Corner Brook and those types of areas. The 2004 capital plan combined with projects currently ongoing in 2003 to relocate a gas turbine to New West Valley and the purchase of a 2.5 megawatt portable diesel, which is already under way, will address some of those radial system, but not all of them. So we're working on some of them as we go forward. We will continue with our engineering efforts in this area to determine viable solutions. This may put upward pressure on the plan.

Another example is that of the customer service system, or you will sometimes hear it referred to as the CSS. It's eleven years old. Replacement of that system could be as high as 15 million dollars. Although we don't forecast a need to replace that system during the five year period presented before this Board in the plan, changing technology and/or a change in vendor support may cause a revisiting of this area.

Q. Mr. Ludlow, do you have any do you have any

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concluding remarks?

(10:17 a.m.)

A. Commissioners, as I've previously stated, the electricity business is premised on several fundamentals, reliability, safety of both employees and the general public, customer service, productivity and the environment. This industry is very capital intensive and it uses long life assets. A refurbishment of the electrical system to improve reliability, excuse me, and performance is a key central aspect of Newfoundland Power's 2004 Capital Budget and remains so throughout the five-year plan as presented. This plan is designed to provide the necessary budget stability, all while ensuring the strength and integrity of our electrical system. Our ability to provide the quality of service that our customers expect and deserve at the lowest reasonable cost will require continuous capital investment. By investing capital in the right places and at the right time we will optimize the asset lives, we're better able to respond to the demands of our new customers and we're able to improve our productivity and the

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MR. LUDLOW:

operational efficiency of our corporation. That is the overall goal of the capital plan.

Q. Thank you, Mr. Ludlow. Mr. Delaney, I would like to ask you some questions with respect to the 2003 Capital Expenditure Status Report found in Volume 1 and refer you to page 1 of 12. That would be the one with the first revisions. Would you please comment on the variances with respect to the 2003 Capital Budget?

MR. DELANEY:

A. Good morning, Mr. Chairman and Commissioners. The 2003 Capital Expenditure Status Report can be found in Volume 1 of the pre-filed Application and is summarized here on the screen. In the first column we have the asset category; the second column is the budget as approved by the Public Utilities Board; the third column shows the forecast as of May 31st; and the fourth column shows the variance as of May 31st. As of May 31st we were a total of 1.3 million or approximately 2.3 percent above budget. Variances from budget are unavoidable due to many circumstances such

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as changes in work due to third party requirements in field conditions, due to changes in priorities, due to ongoing reviews and reassessments of new events and price changes or delays in the delivery of material or in equipment. Now, detailed explanations of individual variances were pre-filed in Appendix A of the 2003 Capital Expenditure Status Report.

Q. Mr. Delaney, earlier in the morning we filed an exhibit PJD No. 1. And this shows the Company's forecast 2003 Capital Budget variances as of July 31st. Will you please comment on the changes in the variances between the May 31st forecast and the July 31st forecast?

A. Yes. This slide shows the most recent Company forecast as of July 31st. Again, the first column shows the asset category; the second column shows the approved budget; and the third column shows the forecast as of May 31st that was filed with the Application; the fourth column shows the most recent forecast as of July 31st; and the fifth column shows the variance between the July 31st forecast

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and the approved budget. The overall variance has increased by approximately $80,000 and now stands at approximately 1.37 million dollars or 2.4 percent above budget.

I'll now comment on the significant changes from the May 31st forecast as filed and our most current information as of July 31st.

The energy supply category has decreased 187,000 since May, and this is due primarily to the reduced cost associated with the penstock replacement at Lockston on the Bonavista Peninsula. We now have a forecast variance of $166,000 in the energy supply category.

The substation category has decreased by $209,000 from May to July. This is primarily due to the reduced cost for the Virgina Waters transformer in St. John's, that's a new installation, a reduction in the substation rebuild project at Blaketown substation and a reduction in a project we are undertaking to improve the protection and monitoring of our substations. We now have a variance of $547,000 below budget in the substations

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category.

The distribution category has increased $152,000 from May to July. And this is due to an increase in the extensions project and the Water Street underground switch replacement project. We now have variance of approximately 1.2 million dollars in this category. And I'll note that this variance is primarily driven by increased customer growth which has increased the extensions and street lighting projects, and there has been an increase in the Glovertown O2 feeder reliability project to accommodate a route that has been approved by Parks Canada through Terra Nova Park.

The transportation category has increased by $300,000 from May to July, and this is due to the replacement of a heavy duty fleet that was involved in an accident earlier this year. The total variance for this category now stands at $487,000.

In the remaining categories there have only been minor changes since the May 31st forecast. And this concludes my discussion on the 2003 capital expenditures.

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MR. MYLES:

Q. Mr. Delaney, would you please provide an overview of each of the categories of the 2004 Capital Budget for which you are responsible here today?

A. The 2004 Capital Budget is summarized in Schedule A of the Application where the budget is broken down by asset category. The total budget is $53,909,000. And I would describe to the Board the projects in the categories listed on the screen with the exception of the information systems category which will be dealt with by a--Michael Mulcahy and Peter Collins.

Q. All right. Looking first at energy supply in Schedule B, page 1. What can you tell us about this category?

A. The energy supply category lists those capital projects pertaining to the Company's hydroelectric and thermal plants. Newfoundland Power operates 23 hydroelectric plants. Our hydro plants provide a low cost and reliable source of electrical energy. Our thermal plants, which are gas turbines and diesels, are located strategically around the

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island to provide a valuable source of backup power. As well, we have portable thermal generation available to respond to emergencies and for construction projects. In 2004 we propose to spend $6,945,000 in the energy supply category, and this expenditure is broken down into four distinct projects. First, the hydro plants facility rehabilitation project is estimated at $1,122,000. And this project is necessary for the replacement or rehabilitation of deteriorated, defective and obsolete hydro plant components. Second, the New Chelsea hydro plant refurbishment project is estimated at $3,973,000. And this project involves the complete refurbishment of the New Chelsea hydro plant. Third, the purchased portable diesel generation project is estimated at $1,700,000. This project consists of the purchase of a second 2.5 megawatt portable diesel generator identical to a unit being purchased this year. And finally, major electrical equipment repairs estimated at $150,000 is necessary to provide for the cost of major equipment replacement due to

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deterioration and catastrophic failures.

Q. Mr. Delaney, could I refer you to Schedule B, page 10? This shows $1,122,000 for hydro plant facility rehabilitation. Could you advise the Board what is proposed here?

A. There are a number of hydro plants that require work in 2004. And I will focus on work proposed in two plants to explain to the Board the nature of this project.

Now, this is our Morris Plant on the southern shore. Our hydro plant operations employees are experiencing problems with the Morris Plant turbine. The wicket gates that perform the critical function of controlling the amount of water that flows through the turbine are not operating properly and we are not getting the amount of production we should from the water resource available, therefore the plant is operating inefficiently.

Now, if we can look at the screen, I can describe this in a little bit more detail. This is the turbine at Morris Plant. The water comes in this turbine, comes around this area, spins the turbine around which creates the rotational movement of the shaft which

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goes into the generator and the water exits through this pipe here. Now, this is inside the turbine. These stainless steel items are called wicket gates. They're not evil, they're wicket. They control the amount of water that goes through the turbine and they are supposed to be lined up in a more linear fashion, I would say. But what's happening is the wicket gates are getting stuck. This one here is clearly stuck, and they're not lining up properly so the water is not flowing as we desire and it's inefficient. It's getting stuck because these things around here, which are called stationary seals, are corroded and the stainless steel is getting just stuck against the corrosion of the stainless steel. So we have a project in next year's budget to improve the efficiency of this plant, to replace these stationary seals.

In Volume 2, Energy Supply, Appendix 1, attachment B of the Application we have filed a report entitled "Morris Plant, Turbine and Stationary Seal Inspection", that explains this item in greater detail.

Another item in this project is to rewind

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generator No. 1 at Rattling Brook plant. Now, Rattling Brook is our largest plant. It consists of two generators. And in 2002 we experienced an unexpected failure in generator No. 2 and the generator coils had to be rewound. That's a labour intensive process that took over eight months.

And just refer to the picture here. This is the generator at Rattling Brook and this generator is actually in a vertical alignment as opposed to the Morris the last time which was in a horizontal alignment. So this is the generator, this is the coils. This is inside the generator and these are the coils. And like I said, there's two generators at Rattling Brook. Last year generator No. 2 failed, and it failed, these coils actually short circuited and, you know, they were rendered useless due to the short circuit. So we had to rewind all this stuff, took about eight months on site to rewind this generator under the conditions we had to work.

Now, both generator No. 1 and generator No. 2 are identical units. Both are 45 years

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old, and it's seen the same duty, the same usage over the years, over the 45 years. The estimated life if a generator winding is 30 to 40 years, in the industry it's pretty well accepted. Given that generator No. 2 windings failed, we are obviously concerned about generator No. 1 and we plan to rewind generator No. 1 in 2004. And this project is discussed in further detail in Volume 2, Energy Supply, Appendix 1, page 3 of 5.

Q. Mr. Delaney, could I now refer you to Schedule B, page 12? This describes a project to refurbish the New Chelsea hydro plant costing approximately four million dollars. Can you please describe this project for the Board?

A. The New Chelsea plant is 47 years old. It's located in the Community of New Chelsea in the Trinity Bay South area. The expected service life of equipment in the plant is between 25 and 40 years. To ensure the continued safe, reliable, low cost and environmentally sound operation of this plant, we need to refurbish the plant. Now, I'll start first from a public and employee safety perspective. The penstock requires replacement. And here is

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the penstock, and here is an up close picture of the penstock here. There are 20,000 wooden wedges in the penstock, over 20,000 to plug holes where the penstock has leaked in the past. And there are over 200 metal plates like this here where more significant blowouts have occurred over the years. As well, we performed ultrasonic testing on a steel portion of that penstock. The penstock is a combination of wood and steel, and we found substantive corrosion on the inside, which leads us to conclude that the penstock has reached the end of its useful service life.

(10:32 a.m.)

As well, the electrical protection, control systems are all of an electromechanical nature, they're original to the plant, 47 years old and we plan to replace those in conjunction with this project, to do a complete refurbishment of this plant. Of particular note on the electrical end, the existing generator protection does not meet current minimum standards. The plant is not protected for stuff such as over voltage, over frequency and there are other electrical

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contingencies.

So, we plan a complete refurbishment of the New Chelsea plant while we have that penstock out of service, the electrical controls out of service, we hope to, you know, decrease our overall capital cost and be as productive as possible by modernizing the entire plant.

And this project is described in detail in an engineering report that has been filed with the Board in Volume 2, Energy Supply, Appendix 2, Attachment A.

Q. Mr. Delaney, what does this slide show?

A. This slide shows before and after pictures. Obviously this is before, and after, of the Seal Cove penstock. This is the new penstock and this is the old one. In 2002 we did this project in New Chelsea and on occasion the new--sorry. We did this job in Seal Cove in 2002. And on occasion the New Chelsea penstock looks like the old Seal Cove penstock. So we intend to repeat the success that we had in Seal Cove in New Chelsea in 2004.

Q. Mr. Delaney, could I now refer you to Schedule

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MR. MYLES:

B, page 14? This states that the Company plans to purchase a second 2.5 megawatt portable diesel generating unit. Can you discuss the reasons behind this project?

A. A backup generation is invaluable in times where there is large scale damage to the power system and customers could be without power for several days. This is especially true for those rural customers served by radial transmission systems that have only one source of supply. A report we filed with the Board in the 2003 capital budget application entitled "Portable Diesel Generation, Reliability Analysis, Sizing and Unit Location Review" recommended the purchase of a five megawatts of portable diesel generating capacity to serve the full load of the majority of our rural distribution lines. Now, due to physical size limitations a 2.5 megawatt diesel generator is the biggest that we can mount on a trailer and make it portable. So in 2003, this year, we've obtained approval from the Board for the purchase of the first portable diesel

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generator. And that unit will be located in Port aux Basques on the west coast, unless it's needed elsewhere for emergencies or construction projects. This project before the Board now for 2004 is for the purchase of the second 2.5 megawatt unit to bring our portable diesel generating capacity up to the recommended five megawatts for emergency backup for our customers on radial transmission systems. When it's not required for emergencies or construction projects, we propose to locate the second unit on the east coast of the province at Trepassey substation.

Q. Mr. Delaney, could I refer you back to page 2 of Schedule B? This shows the substation category. Can you give the Board the highlights of this category?

A. Newfoundland Power operates 137 substations. The fundamental purpose of a substation is to transform voltages from transmission level to distribution level and to protect and control the transmission and distribution of power. In 2004 we propose to spend $5,199,000 in the substations category. This expenditure is broken down into seven projects, as shown on

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the screen.

The rebuild substations project of $1,000,023 is necessary for the replacement of deteriorated and substandard substation infrastructure.

The replacement and standby substation equipment project estimated at $1,314,000 is required to replace obsolete and unreliable electrical equipment and to maintain an appropriate level of spares to use during emergencies.

The transformer cooling refurbishment project at $398,000 is required to replace corroded radiators on our substation transformers. This will prevent oil spills and the associated environmental clean up costs.

The protection and monitoring improvement project at $80,000 is needed to make small upgrades in our protection and control systems in substations.

The distribution feeder remote control project at $1,000,000 is a project initiated in 2002 to replace a number of aging, limited function electrical mechanical relays, feeder

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relays and oil filled reclosers with modern units that can be remote controlled island wide from our system control centre in St. John's.

The project for feeder additions due to low growth and reliability at $200,000 is necessary for upgrades at two substations to accommodate customer growth and reliability issues.

The increased Corner Brook transformer capacity project at $1,184,000 is necessary to prevent forecasted substation transformer overloads.

Q. Mr. Delaney, could you now refer to page 18 of Schedule B. Could you address the substation rebuild project at a cost of $1,023,000 and advise the Board what is proposed here?

A. There are a number of substations that will require work in 2004. And I'll focus on the work proposed in two substations to explain to the Board the nature of this project.

This is the Grand Bay substation in Port aux Basques. We are experiencing problems in this substation due to congestion. There is simply not enough room for the equipment

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that's stationed there. Our portable gas turbine is located at this substation and our 2.5 megawatt portable diesel generator will be stationed there when it arrives later this year. The substation must be modified to ensure that there are no delays when this portable equipment is required during emergencies to restore service to customers, as well, a better layout is required to avoid employee safety concerns associated with congestion at this substation. And this item is described in Volume 2, Substations, Appendix 1, page 1 of 6.

This is our Indian Cove substation on New World Island. The substation is 35 years old, it's a small substation, and it's at the end of its useful service life, must be upgraded. The substation transformer has severe rusting. There's a risk of an oil spill, which is an environmental concern. And our reliability concern is in that the wooden cross arms have burn marks and some are severely bent. As well, the switches, and I'll just point some of these things out here, the transformer here

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has rusting. Of course, we're concerned of an oil spill. And the cross arms, which are these timbers going across here, there's burn marks. There's one here, it's hard to see on the picture, but it shows that there's evidence that there's been trouble on this line and of course, the strength of this cross arm is severely reduced by that burn. And there's some severe bends in the cross arms. As well, the switches are out of alignment due to the torsional type of movement that's going on with the poles. And that makes some--it's a safety hazard for our employees, the switch that's out of alignment. And this item is described in further detail in Volume 2, Substations, Appendix 1, page 2 of 6.

Q. Mr. Delaney, could I now refer you to Schedule B, page 20? This is a project for $1,314,000 for replacement and standby substation equipment. Could you please describe this project to the Board?

A. The replacement and standby substation equipment project involves the purchase and installation of substation equipment to address issues of obsolescence and

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deterioration. As well, the project ensures we maintain an adequate level of spares in our inventory to address emergencies and to ensure that maintenance activities are carried out in an efficient manner. A typical item in this project is breaker replacement. Now, this is a 66,000 volt circuit breaker located at Pepperal substation in Pleasantville, St. John's. The breaker is 51 years old. It is a one of a kind in our system right now. The parts are obsolete. We can no longer purchase spare parts for this breaker. In 2004 we plan to replace it with a new SF6. So this is the old breaker here, it's 51 years old, like I say, and we just don't have spare parts for it any more and can't get them. It also has to operate quickly to get faults off the system and it's just not sufficient. This is the newer breaker, which is an SF6 breaker that we will replace the older breaker with. This project is described in further detail in Volume 2, Substations, Appendix 2, page 1.

Q. Mr. Delaney, could you now refer to page 26 of Schedule B? This addresses the distribution system feeder remote control project. Could

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you describe the one million dollar expenditure to the Board?

A. In 2004 we are continuing with a program started in 2002 to install distribution feeder remote control. Each of our 300 distribution feeders has a device to control and protect the feeder, either a relay or a recloser. Should a power line fail or should, like, energize wires fall to the ground, this is the equipment that we depend on to operate automatically to ensure that the power is disconnected. The screen shows old and new relays and reclosers. In 2004 we plan to install 25 new relays and six new reclosers. By the end of 2004 we expect to have a total of 65 new relays and 36 new reclosers installed in the system. And this project is timely due to the age of the equipment being replaced and there are several benefits.

And I'll go through some of the benefits with this new technology. The first is we're improving reliability. The new technology enables the system control centre to monitor and control distribution feeders. The system control centre operators can quickly pinpoint

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trouble spots and direct the field crews accordingly. And there are instances when the operators can restore power without dispatching anyone in the field, and this reduces outage durations for customers. Second, we're minimizing the risk due to oil spills. The old reclosers that we have, they utilize about 200 litres of oil, and oil is needed to extinguish the arc that occurs when the break happens in the electricity, opens the electricity. The newer reclosers have no oil, that activity, that breaking of the arc occurs in a vacuum chamber. Third, we are reducing operating costs by bringing in this new technology. And a very good example of that is tree trimming around power lines. Tree trimming is something we do every year. We continually have to monitor and trim the vegetation around power lines; it's an essential part of the operations. So, on feeders without this technology, we need to send somebody to the substation at the beginning of each day to adjust settings at the substations, then the contractor can go to

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work, do his tree trimming. And then at the end of the day, we have to go back to the substation and adjust settings back again. On feeders with this new technology, the tree trimming contractor would call into our system control centre and all those adjustments are all now done remotely. So, this is saving us a lot of time, going to substations and cutting down on our costs.

Q. Mr. Delaney, could I refer you to page 30 of Schedule B? This is a project to increase the Corner Brook transformer capacity, could you describe this project to the Board?

A. In Corner Brook, we have seen gradual customer growth. There are the new developments at the Sir Wilfred Grenfell College with the addition of several building, the Canada Games Centre is in this area as well. There is a big box retail development in Corner Brook at Murphy's Square which includes Wal-mart, Dominion, Canadian Tire, Staples and other strip malls. As well, there has been residential subdivision developments such as Sunnyslope. Now, customers in Corner Brook are served by three substations, Walbournes, Humber and

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Bayview. And each of these three substations is interconnected. Installing a new transformer is a big ticket item. It's a lot of money to put a new transformer in, as you see, it's over a million dollars. So, for the past number of years, we've been successful in deferring the need to put this new transformer in Corner Brook, in a substation. And we've done this by transferring the loads between substations. For example, as the Walbourne's transformer would approach overload due to developments up around, say, the Sunnyside subdivision, Sunnyslope subdivision, we'd install switches on the distribution feeders and redirect parts of the load to Humber, Bayview, that's a fairly small cost thing to do, to redirect the loads.

Now, we've now reached a point where that approach is no longer feasible. We're projecting this year that the peak load in Corner Brook will be slightly greater than the total combined capacity of all three substation transformers. So, now we have to add the additional capacity. We studied this situation, we looked at alternatives and

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decided that the least cost alternative is to install a new 25 MVA transformer at the Walbourne substation and as well, we have to relocate the smaller of the two units currently in service at Walbournes over the Bayview substation.

(10:47 a.m.)

And I'll refer the Board to Volume 2, substation, Appendix 4, Attachment A where this a report entitled power transformer study, city of Corner Brook which describes this project, the alternatives considered, the financial analysis, et cetera, describes it in detail.

Q. Mr. Delaney, could you refer back to page 3 of Schedule B? This shows the transmission category, could you describe this project to the Board?

A. Newfoundland Power operates 110 transmission lines that have an overall length of greater than 2000 kilometres. And 30 percent of our transmission lines are more than 40 years old. In 2004, Newfoundland Power proposes to spend $2,315,000.00 to upgrade its transmission line system. And this work is identified during

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the course of annual inspections carried out on transmission lines. Within this overall project there are several items and I'll discuss two in detail to give the Board information on this project. The first is a $380,000.00 expenditure to rebuild a 5.1 kilometre section of transmission line 403L. And this is a picture of transmission line 403L that runs from St. Georges to Robinsons to our Lookout Brook hydro plant on the west coast in the Bay St. George area. This line was built in 1958 and inspections have determined that there is significant deterioration of the poles, cross arms and other hardware. And extensive upgrading is needed to ensure the continuity of service for customers in this area. And this transmission line, as I said is 45 years old, has reached the end of its useful service life.

The second item is $197,000. 00 expenditure to increase the conductor or wire size on transmission line 16L. Now, this is 16L. I just want to point out that the transmission line is the top circuit, three

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wires, one of the wires is kind of hidden, they're small wires. And below, this is actually a distribution feeder. So, this is what we call underbuild. In St. John's, there is quite a bit of that. But this is a 16L, it's a short line, runs along the Boulevard from Pepperell substation in Pleasantville to King's Bridge substation near Memorial Stadium. Now, we've filed a report with this application in Volume 2, Transmission Appendix 1, Attachment A, entitled "The St. John's Transmission Capacity Review". And in that study, we used engineering models to analyze the St. John's transmission line system during contingencies. Now, a contingency is when one transmission line fails. Because the transmission system is all interconnected, when one transmission line fails, there's effects on other transmission lines. If the load that was normally flowing on a transmission line fail, the load would go different ways to get to the customers. So, this was a fairly complicated study; it's filed with the Board, analyze these contingencies. And we've determined that our

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contingencies that should another transmission line fail, 16L will overload and the risk there, 16L, the conductor is just not big enough to handle the load. So, that's a weakness, the small conductor size on 16L transmission line. And the risk there is overload conductor, the conductor can burn off and it could result in an outage on the entire east end of St. John's, from St. John's right down to Pouch Cove. So, we have to increase the conductor size on 16L.

Q. Mr. Delaney, could I now refer you to Schedule B, page 4? This shows the distribution category and can you describe these expenditures to the Board?

A. Newfoundland Power is primarily a distribution company. We operate over 8000 kilometres of distribution lines to serve approximately 220,000 customers. Capital expenditures in the distribution category amount to $27,636,000.00 or 51 percent of the entire budget. Approximately one half of the distribution category or one quarter of the entire budget is associated with providing service to new customers who wish to connect

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new homes and businesses to the power grids. And the cost to connect the new customers is included in the first five projects listed on the screen. These are extensions, meters, services, street lighting and transformers. In the distribution category we have listed as well, the Aliant pole purchase at approximately $4,000,000.00. This is an expenditure previously approved by the Board for the acquisition of Aliant joint use poles. As well, we have a $100,000.00 estimate for interest during construction and this is an amount calculated in accordance with order number P.U. 37 (1981).

Q. Mr. Delaney, could I now refer you to page 44 of Schedule B? Can you explain to the Board, the nature of the expenditure of about 2. 4 million dollars shown there for reconstruction?

A. Reconstruction expenditure is driven by a distribution feeder inspection program that works in a five-year cycle such that 20 percent of distribution system is inspected annually. We filed with the Board our Distribution Inspection Standard in Volume 3,

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Distribution Appendix 2, Attachment A. These inspections are required to ensure the safety and reliability of our system. During the course of these inspections, we identify numerous deficiencies and depending on the severity, the deficiencies are priorized in four categories; Emergency, Priority One, Priority Two and Priority Three. Emergency and Priority One deficiencies are covered in the reconstruction account in the current year. Priority Two and Priority Three deficiencies are identified for capital expenditure in the following year under a project called Rebuild Distribution Feeder Upgrades.

Now, this is a deficiency found during our inspections this year, it was in Caribou Road in Corner Brook. The pole is leaning on an angle such that we would classify it as a Priority One deficiency and we're now working on this project which may require the replacement of several poles under the reconstruction account. And it's a very--this may, because when you replace a pole, it

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usually has an effect on the adjacent pole. I actually visited this pole over the weekend in Corner Brook and this building has been torn down. So, it's going to make this job a lot easier to do, to correct this deficiency. Another aspect of the reconstruction expenditure is to address minor storm damage and items of imminent failure that come to our attention that are outside the inspection program.

Q. I'd like to refer you first to page four of Schedule B and then from there to page 47 of Schedule B. Can you describe the Distribution Trunk Feeders Project?

A. Yes, this project entails a variety of work we plan to do to upgrade the distribution system in 2004. The majority of the expenditure, approximately two thirds is for feeder upgrades and this ties into the reconstruction project described previously. Coming out of our annual inspection process, we'll identify numerous deficiencies on our distribution system. The Emergencies and the Priority One deficiencies are addressed under the reconstruction account in the current year, as

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I just noted. But those deficiencies deemed to be Priority Two or Three are completed in the following year under the Rebuild Distribution Project, Feeder Upgrades. As well, there are a number of safety, reliability and environmental concerns addressed in this project. These concerns are described in a number of reports that we have filed with the Board in Volume 3, Distribution Appendix 2, Attachments B through G. The picture shows three of these concerns we are addressing with the rebuild distribution project. The green box in the top picture is a pad mount transformer. These transformers are exposed to road salt, mechanical damage by snowploughs and there's a degree of undermining and back filling that happens by property owners in the course of landscaping their properties. These transformers are located in residential neighbourhoods and therefore, we have a concern for safety and the prevention of oil spills. We expect to replace about 300 of the 400 pad mount transformers we have in service in St. John's over the next five years as these units reach

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the end of their 30 year service life.

The middle picture is two broken cutouts, failure of porcelain cutouts is a safety and reliability problem. Cutouts are mechanical switches for distribution lines. They are used to disconnect and reconnect power to a distribution transformer and branch lines. Our line employees use hook sticks to manually open and close these cutouts. So, failure of the cutout is a safety concern for a line personnel who must be in close proximity when manually operating these devices.

The bottom picture is a deteriorated automatic sleeve. Automatic sleeves are used to connect two pieces of wire together. The problem with automatic sleeves is one of internal corrosion. In 2002, we have a sleeve failure and performed an investigation. We took 35 automatic sleeves out of service that were in the field and found 13 to be severely corroded. When an automatic sleeve fails, there's a possibility that the energized wires can fall to the ground which poses a serious safety hazard for employees and the general public. So, we've included automatic sleeve

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replacement in our five-year distribution inspection cycle.

Q. Mr. Delaney, can I refer you to page 52 of Schedule B? Can you describe the distribution reliability initiative?

A. In 2004, we plan to continue the distribution reliability initiation and focus on three areas of reliability concern in the distribution system. These are the Lumsden, Cape Freels area, Bonavista North served by distribution feeder Wesleyville 02, the Bay Roberts, Port de Grave area served by Bay Roberts 04 feeder; and finally the Torbay, Flatrock, Pouch Cover area which is served by the Pulpit Rock 01 and Pulpit Rock 02 feeders. I'll focus on the Wesleyville 02 item to explain to the Board the nature of this project. The Lumsden, Cape Freels, Bonavista North is served by the Wesleyville 02 distribution feeder. Now, this item is estimated at $699,000.00 in 2004 with a further $400,000.00 in 2005 to complete the feeder. We have filed with the Board a report with this application found in Volume 3,

Distribution Appendix 3, Attachment A, entitled, "A Review of reliability, Wesleyville 02 feeder". The feeder is 40 years old and as the line ages, it will not withstand the severe weather conditions in which it must operate. This is an area frequented by sleet and strong winds. Reliability performance has been well below the company average. This year, in fact, the reliability performance on Wesleyville 02 is eight times worse than that company average. 2002 was another bad year, we experienced eight outages on this feeder. Due to the distribution feeder, we experienced eight outages. This resulted in a letter of complaint, meeting with local municipal council. The lines should be rebuilt 2004/2005 to a heavier load design and to a stronger construction standard to withstand the environment in which it must operate. And by budgeting and planning this way, we will significantly improve the reliability in an organized and productive fashion. Otherwise, there's a risk that storms will continue to cause damage, costly damage that must be

repaired under rushed emergency conditions to get the power back on with no significant improvement in the long run.

(11:02 a.m.)

Q. Mr. Delaney, at page 54 of Schedule B, there is a project entitled, "Feeder Additions and Upgrades to Accommodate Growth", estimated cost of $677,000.00, can you describe this project to the Board?

A. The biggest item in this project is to construct a new feeder, Chamberlins 03 from the Chamberlins substation in Conception Bay South. This will cost $522,000.00 in the distribution category and will require a further expenditure of $106,000.00 in the substations category. I'll take the Board through the slide to explain what we're doing. Customers in Conception Bay South are served by three interconnected substations. They are Seal Cove, Kelligrews and Chamberlins. Now, the immediate problem here is the substation transformer is overloaded in Seal Cove and the substation transformer in Kelligrews is forecasted to overloaded this year, in Kelligrews. So, in order to determine the

best, least cost solution over the long-term to serve the growth in this area, we undertook a study of the entire area which has been filed with this application and is in Volume 3, Distribution Appendix 4, Attachment A. The least cost alternative to supply the growing needs in Conception Bay South is to construct this new feeder, Chamberlins 03 and we'll go along the CBS bypass road down towards Kelligrews.

Now, this alternative takes advantage of the additional transformer capacity that we're installing this year in Chamberlins. So, what's going to happen is we're going to off load Kelligrews onto this new feeder, Chamberlins 03 feeder. So, that will eliminate the overload in Kelligrews and cascading, we'll off load Seal Cove onto Kelligrews and that will do us well into the future to handle the growing needs.

Q. Mr. Delaney, if I could refer you now to page -

CHAIRPERSON:

Q. Mr. Myles, I think we were going to take a break at 11:00, we're a little bit past, so

CHAIRMAN:

unless you're going to be a short further time with Mr. Delaney?

MR. MYLES:

Q. I'm guessing 10 minutes, 15, 10 I'd say, I only have another eight pages here.

CHAIRPERSON:

Q. All right, we'll adjourn at this particular point in time and come back at 11:30.

MR. MYLES:

Q. Yes.

(RECESS - 11:04 A.M.)

(RESUME - 11:33 A.M.)

CHAIRPERSON:

Q. Mr. Myles, carry on, please.

MR. MYLES:

Q. Thank you, Mr. Chairman. Mr. Delaney, can I now refer you to page 56 of Schedule B? This refers to a project estimated at $750,000 for switch replacement and upgrade underground distribution on Water Street in St. John's. Can you describe this project to the Board?

MR. DELANEY:

A. This is a project which started in 2000 to upgrade the underground system along Water

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Street in St. John's, and 2004 will be the last year of this project. There are two concerns that we are addressing in this project. The first concern pertains to the safety, deterioration, obsolescence of the underground switches that are located in manholes under Water Street. These switches are no longer supported by the manufacturer and here we have a picture of one being taken up from underground and there's severe corrosion on these switches. So this is since 2000, seven of the thirteen switches had been replaced. Five are planned for this year and in 2004, the one remaining switch will be replaced.

A second concern in this area are the transformer banks that are mounted on platforms along several of the streets that connect Water Street and Harbour Drive. These transformer platforms are beyond their estimated service life of 30 years, and as well, there is safety concern when customers need to perform maintenance on the exterior of their buildings in close proximity to these platforms. This slide shows Baird's Cove in

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St. John's and if you go along Water Street and Harbour Drive, you notice going through these side streets, there's a lot of platforms. Now this is during construction here. The platform is being removed. You notice this platform, there are two poles, some crossarms, a platform and there'll be three transformers. In Baird's Cove, we had one on this side of the street and one on the other side of the street. Like I say, this is during construction. Obviously in close proximity to these buildings, actually opening up these windows, they're within arm's length of the platforms, and this is the situation on Baird's Cove now. The platforms have been removed. I'm advised that this streetlight pole is going to be removed as well. So we're continuing on with this work, upgrading a number of vaults in buildings to relocate these transformers off the platforms into vaults. In 2004, we plan to remove the remaining platform mounted transformers.

Q. Mr. Delaney, can I refer you back to page five of Schedule B? This shows the general property category and can you describe this

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project for the Board?

A. The general property category is $709,000 or just over one percent of the total budget. This category includes expenditures related to upgrading buildings, real property. For example, we are replacing the roof on our Stephenville building. A portion of this roof was damaged by high winds earlier in 2003. A second component of the general property category is the addition and replacement of tools and equipment. In this job in the picture here, we have our lineman performing what we call hot line maintenance, and they'll actually upgrading this structure while the line is still energized. This line is still carrying high voltage. So that avoids an outage to our customers and we can perform the capital maintenance. All this orange equipment is what we call hot line equipment. So it's obviously required for safety reasons. So should that equipment not comply to the high standards that we hold for that equipment, it must be replaced.

Q. Could you now refer to page six of Schedule B, and this shows the transportation category and

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MR. MYLES:

can you describe to the Board what this category includes?

A. The transportation category includes $3,487,000 or approximately six percent of the total budget. We will not be increasing the size of the fleet. However, we need to replace twelve of our heavy line vehicles, fifteen passenger vehicles and nine small all-terrain vehicles, such as snowmobiles and trailers. We continue to review the mix of vehicles to ensure--to increase our overall utilization and to reduce our costs. For a passenger vehicle, a replacement guideline is five years, 150,000 kilometres, and for a heavy fleet vehicle, the replacement guideline is ten years or 250,000 kilometres. Now this guideline initiates a review of the vehicle maintenance costs, its operating history and the condition of the vehicle before a decision is made to replace.

Q. Now can I refer you to page seven of your Schedule B, and this shows the telecommunications category, and can you advise the Board what this category includes?

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A. The telecommunications category is $120,000 and that's less than one percent of the total budget. We have 340 mobile VHF radios in service and we replace about 20 of those radios each year, as they become unreliable. As well, this project includes teleline isolation equipment at several of our substations, and this equipment is required to improve the safety for utility and telecommunications workers from the possibility of high voltages that may occur on telecommunications circuits in substations.

Q. Can you please give us an overview of the general expenses capital?

A. The general expenses capital is $2,800,000. General expenses capital is the amount of Newfoundland Power's administrative expenses that are charged to capital, and it is calculated in accordance with P.U. Order No. 3 (1995/96).

Q. Now could I ask you to refer to page nine of Schedule B? This shows an allowance for unforeseen items, and can you advise the Board of the purpose of this allowance?

A. The unforeseen allowance is $750,000. This

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allowance is necessary to cover any unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the allowance is to permit the Company to act quickly to deal with unforeseen events in advance of seeking the specific approval of the Board.

Q. Mr. Delaney, do you have any concluding remarks with regard to the 2004 Capital Budget?

A. I have described a number of capital projects that are needed to serve the new and existing customers with reliable power supply that is consistent with least cost. These projects have been developed and prioritized through a budget process that involves our front line employees, such as line persons, hydro plant operators and industrial electricians. The process involves our engineers and our technical personnel, as well as the managers and the executive of the Company.

And I'll close by referring the Board to the picture on the front cover of the application. This is a number of line crews; you can see six in the picture, and they're

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working in the Codroy Valley on the Doyles 01 feeder reliability project last year. This was a successful, safe and a very productive job, and as an anecdote, one of our linemen commented that we did six years of work in six weeks. So to have that good productivity on the job, we need good planning, and this budget application contains the planning necessary for the prudent and successful deployment of our capital resources in 2004. Thank you.

Q. Thank you. Mr. Chair, that's the conclusion of the presentation. I would propose to provide copies of the slides which have been a part of this presentation, and would propose to have them marked as Exhibit EAL-1.

Thank you, Mr. Chairman. Mr. Ludlow and Mr. Delaney are now available for cross-examination.

CHAIRPERSON:

Q. Thank you, Mr. Myles. Mr. Young.

MR. YOUNG:

Q. Thank you, Mr. Chair. Good morning, gentlemen, Mr. Ludlow and Mr. Delaney. I'd like to start, if I might, with a general

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MR. YOUNG:

question about the process Newfoundland Power goes through in the Capital Budget. Perhaps I could refer you to NLH-1, please.

CHAIRPERSON:

Q. What was that reference again, Mr. Young?

MR. YOUNG:

Q. NLH-1, request for information.

CHAIRPERSON:

Q. Fine.

MR. YOUNG:

Q. There's two concepts there which I'd like to discuss a little bit, and the first is the preliminary engineering reviews and design, and the other is detailed engineering. I wonder if either of you, and I'm really not fussy as to which one chooses to jump in and do this, but if either of you could please explain the difference, as you see it, as this works in your company?

MR. LUDLOW:

A. Mr. Chairman, there's a fundamental difference in both, and I would take you back to one of the projects that was described in--Mr. Delaney described it actually, was the Water

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Street underground as an example. If I were to go back to the early '90s, in particular '92/93, there was an identification of a concern starting to grow with respect to the condition of plant, with respect to the condition of the cabling, what we call the potheads to joiners and so on, and we knew that there was something had to be done in the Water Street area, and the initial thought process that we went through in subsequent years, until we filed--I do believe it was in 1999, we were doing what I would call general concepts in engineering at that point in time. More along the lines of we knew that we had an issue, the easy way out of this would be to simply pull out one switch and put another one back in. However, when we filed, we filed, and I do believe it was '99, it might have been 2000, but it was in that general range before this Board in a capital hearing, and we identified the problem and we basically laid out what we would see as the general cost parameters at that point in time to address the issue. Subsequent to the approval of the generic engineering and the project coming

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forward, we then would immediately roll into what I would call detailed engineering. And by that, what we would do is we would take the section that would be developed in the project that was put forward at that point, a multi-year project or multi stages. We would take the section, we would look at what is the best solution, what is the most cost effective solution, what is the most customer friendly solution, and what is the best engineering design that would fit that, and now you're down to CAD drawings, you're down to specifications, you know, on switch gear or civil works, and now I'm getting right down to what I would call, to use my terminology, the brass tacks of the task at hand, and that would occur sometime between, in this case, now and the actual construction, which would be next July. So that's the differential, Mr. Young, or Mr. Chairman, that I would use in that, and that's an example that we would go.

Q. So just want to clarify that, generally speaking then, the detailed engineering in projects of that sort is done after the capital budget item has been approved?

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(11:48 a.m.)

A. That's generally the case. We do not have, and we've stated this clearly here many times, that the line item detailed engineering has not been completed. However, we have done, I would take it to the feasibility level. I'd almost look at it as ranges of comfort. The job must be done. We know some of the solutions, but we haven't scoped in detail all of the respective solutions. Any capital project that we put before this Board, Mr. Chairman, again, is subject to continuous review prior to execution. Namely, if in fact it has to be done will be revisited at the time of any expenditures, and that's a statement that we've always gone forward with.

Q. Just a little further on that page you talked, and Mr. Delaney had mentioned this this morning, touched upon it at least, a couple of concepts we'd like to know a little bit more about. One is justification categories and the other is priority codes. I'm just wondering exactly what they are. I think we have some sense now of what the priority codes are, but how that fits into the process?

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MR. DELANEY:

A. If I could refer the Board, in terms of priority code, if I can refer the Board to Volume 3, distribution, Appendix 2, Attachment A.We have here our distribution inspection and maintenance procedures and this particular document drives a component of our reconstruction project and our feeder upgrading project, which is under "rebuild distribution line." In this document, on page five, we have our classifications of priorities and the people that do the inspection on the distribution feeder will identify deficiencies and list them in this order of emergency--the table indicates emergency, priority one, priority two, priority three, which with a recommended response time. Now in further detail, if we can go along in Appendix 1, we've broken that down. Appendix 1 in the same report, three pages on from there, to give our employees some indication, in terms of the different components of the distribution system, what we would consider an emergency, a priority one or priority two. For instance, in conductor

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damage, just to take one example out of the list, our guideline, if there is more than one quarter of the strains broke in a conductor, that's an emergency, let's get something done immediately. If there's less than a quarter of the strains--a conductor is made up of numerous strains--less than a quarter of those broken, priority one and priority two. So this is some indication of the priority that we put on some of our capital work.

Q. Question occurs to me about, if I can go back for a moment--sorry to bounce around here, but back on detailed engineering issue, and I don't think we need to turn to it, but the report in Volume 2 about the New Chelsea plant, there's a fair bit of money in that project and I understand that once this is done, there's supposed to be a significant number of years expected from New Chelsea without further capital expenditures of any great amount. I wonder if you could characterize that report? Is that detailed engineering or is that prior to that? That's the feasibility plus? I wonder if you could just give some real terms in that context?

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MR. LUDLOW:

A. Mr. Chairman, where I would categorize the report being referred to that's presented before this Board, this would be at the plant assessment and feasibility and acknowledgement of how we would, in fact, have to move with this plant to keep it viable to run. To take that and move it to detailed engineering, we'll get down to the decisions that are highlighted within this report. If you wish, it's energy supply, Appendix 1, is where the report is. Might be just as well to go there.

MR. DELANEY:

A. Appendix 2.

MR. LUDLOW:

A. Sorry, let me straighten that out. It's Appendix 2, Energy Supply, Volume 2.

Q. Attachment A.

A. Attachment A.

CHAIRPERSON:

Q. Appendix 2 you say?

A. That's correct, yes, sir, Mr. Chairman. Appendix 2, Energy Supply, Attachment A. This is the New Chelsea plant refurbishment 2004 report, which is a further consolidation of

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multiple reports, mechanical, civil, electrical. I think that would be the piece. That's basically, Mr. Chairman, is a condition assessment. It would be both on all those fronts. It would go into detailed assessments, for example, into ultrasonic testing of the steel portion of the penstock, showing that it's less than or approximately 50 percent of the steel remaining in places. So it's that condition assessment. The estimating that is done is based upon our past experience in work in hydro plants. But getting to the detailed engineering here, whether we use fibreglass, steel or woodstave and what the exact routing, the routing most likely would stay the same, and down to the drawings of that has not been completed at this stage. The governor, whether it's hydraulic, electric, electric hydraulic. We know that the decision must be made, but that fine detail has not been engineered at this point in time. Similarly, with the controls, that's been highlighted here as well. But the feasibility stage has taken us here. The judgment had led us to this point, and that's

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MR. LUDLOW:

the distinction between the two. If -

MR. YOUNG:

Q. No, I think that's a full explanation. I wonder if I could refer you next to a different area. It's NLH-3, and the project in question here is the hydro plant facility rehabilitation. I understood, Mr. Ludlow, in last year's hearing, Newfoundland Capital Budget hearing, we had a brief conversation from this format about the beauty of old hydro plants and that they usually are long paid for and the incremental capital costs required to keep them safe and reasonably reliable is small, incrementally small, and that provides good low cost power. I think you'll probably recall that conversation.

A. I agree with you.

Q. In this RFI, there is an example given here in relation to the question about sometimes the difficulty of dealing with projects of this sort in analysis in a quantitative basis, and the example given is Pierre's Brook. I understand that in Pierre's Brook, you know, the issue is the--at some point, at least,

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there's a safety issue because it's a penstock headgate. But I also notice that there is a reference to the number of gigawatt hours of annual production. I'm just wondering, is the reference to the annual production there for a particular reason, insofar as there's a concern if the penstock headgate is not repaired that you might lose production for a full year? Is that why the annual figure is given?

A. Specifics as to why the 25.3 gigawatt hour reference is made in NLH-3, it would not be for that reason. It would be here to give an example of this is the energy output of this plant. The headgate is a very vital part of this system. This headgate is--I've got the number. It escapes me right now. Just bear with me one second. That headgate is 1931 it was installed, and it is a vital part, from a safety perspective, for that area, for that plant. Now do I do my justification on a $91,000 headgate expenditure back against 25.3 gigawatt hours? No, but I would have to say that I've got some significant safety issues on a 70-year-old headgate that's not working,

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and that headgate is vital. You mentioned safety. I'm not willing to put a price on a person's life, and I don't think that's your indication, Mr. Young.

Q. No, certainly not.

A. And that becomes that balance. If we were to overhaul Pierre's Brook top to bottom, that being dammed, penstocked, the whole thing, we would do the same type of process through inspections, what we've seen, dam safety inspections, where this has come from, bring it forward and consolidate it into a report. So I don't know if I've answered your question, but it's there to give a level--this plant is a valuable plant to our system.

Q. So in this instance, did the number of gigawatt hours, that's really just a descriptor to give us some idea of the size of the plant. I'm just wondering if we can move to another one, by way of example, and we've already touched on it this morning, the Morris plant, and the questions that I had, I suppose if we want to have a reference, it's in Energy Supply, Appendix 1, Attachment B. This would be what Mr. Delaney spoke about this morning

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and showed us the pictures. The project is the turbine and stationary seal, little over $100,000. Just so I understand, this is a relatively recent plant. It's about 20 years old? Is that correct?

MR. DELANEY:

A. The date of manufacture, as shown in the report, of the turbine is 1983, so it's 20 years old, yes.

Q. Where is this located? This is on the Southern Shore, Morris?

A. That's on the Southern Shore, yes.

Q. Yes. Now in Attachment B, it says that the plant is about 1100 kilowatts capacity and you get 7.2 gigawatt hours annually. It's a fairly high capacity plant, around 75 percent, but that's not terribly germane to the issue. The justification on page 305, that would be in Schedule B--no, it would not.

CHAIRPERSON:

Q. Where did you reference, Mr. Young?

MR. YOUNG:

Q. I'm having a little bit of trouble finding my reference here, but I certainly remember the words, because, as is the case with a lot of

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MR. YOUNG:

these things, they're in one place or another. I don't need to go right to that reference right for the moment, but the justification relates to the reliable production of energy from this facility and I think this morning you spoke about the problems with the wicket gates operating sluggishly and not getting optimum production. Is that correct? Are the turbine runner seals critical to the safety in the same way that the penstock headgate is in the Pierre's Brook thing? I take it it's a different kind of an issue.

A. It would be, you know, a different kind of an issue with respect to safety, but I wouldn't feel too comfortable knowing that the wicket gates were sticking and we have problems with internal corrosion of the turbine, from a safety perspective.

Q. And I'm not suggesting that we shouldn't do otherwise but to make sure that the hydro plants operate efficiently. I just want to make sure it's that sort of an issue. Is there any concern about these seals failing completely or is it a matter of fixing them to

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optimize production? If they fail completely in some way, completely got stuck and caused a real problem for the way this work, would that essentially require the plant to be shut down and some sort of emergency basis?

A. If the seals, the wicket gates failed completely, yes, that would cause a shutdown of the plant.

Q. Okay. Do you have any idea how long that would take to repair?

A. How long it would take to repair if -

Q. Yes, you know, the job you're -

A. - a catastrophic failure or -

Q. Yes. No, I guess my question relates to, you know, you're planning to do this work to fix this problem and when you plan to do work, of course, you can optimize your schedule, you can do it at a time when the plant perhaps can be taken out of service with the least impact. If it was required to be done because it happened at a time which wasn't optimum and you had to go in and do that repair, would it be a different period of time?

(12:03 p.m.)

A. If the unit were to fail unexpectedly, it

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would take much longer to do it, under much more stressed conditions than if it were to be repaired in a planned, organized fashion.

MR. LUDLOW:

A. Mr. Chairman, one of the topics in this area in particular, if I may help, some point of clarification to add to this, is that if that wicket gate failed during spring run-off, depending on where that wicket gate went, an example being last year, we had a major catastrophic failure at a Seal Cove plant. We were out of commission. Just put the safety at one point, loss production at another point, the lost productivity of the workers, organization and planning being a third point, and Mr. Young, I don't know if those are the points.

Q. Yes.

A. But as you put all that together, this becomes a real serious problem. What we're dealing with with these seals here, I mean, it's been identified, we're putting water through. This is an upstream plant from a downstream producer, memory escapes me. It may even be Pierre's Brook actually or one of those

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plants.

MR. DELANEY:

A. It's upstream from Mobil.

MR. LUDLOW:

A. Mobil. And what's happening, that's a flow through plant. That's the reason the load factor is so high. Now if we're putting water through that plant and not maximizing the, I use the term electrical engineer speaking, value per gallon, but then, I think our efficiency loss as a result of this stuck headgate is a real issue for us, and hence, the reason that this has been put forward, and it is a concern. There's continuously people going back and forth to that plant as well.

Q. I was just trying to narrow in on the justification here and certainly the evidence you've given this morning is helpful. From the point of view of looking at this quantitatively, insofar as it can be done here, I notice in NLH-7, and I don't know if we need to refer to it, but you refer to a 5.13 cent per kilowatt hour value of increased Holyrood production that's avoided essentially every time you keep--that's per kilowatt hour

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MR. YOUNG:

figure, that's avoided every time you keep a hydro unit running and producing a kilowatt hour, and I accept your point about energy you produce prevents, or not prevents, that's certainly not the right word, allows Hydro to produce less at Holyrood and relatively equal amounts and almost whenever it occurs. Simple arithmetic for me, this is 7.2 gigawatt hours of annual production that this plant, roughly $350-370,000 a year. I don't know if I know yet whether or not an assessment has been done as to how much energy would be expected to be lost if, in fact, this project wasn't done and failed or, indeed, for that matter, how much would be expected to be lost with this project if it just has to be taken out of service for the job to be done.

A. Whether that has been done--Phonse, do you want to take this?

MR. DELANEY:

A. No, you go ahead.

MR. LUDLOW:

A. On that topic, I don't have that number with me, Mr. Chairman, but there's a combination of

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factors, as I did go forward and say a few minutes okay. This is in place. We're continuously fighting to reduce the oil consumption in this province. We have a plant in place that we know has an identified problem of a stuck wicket, and I watch the T and the D in that word all the time, wicket gate. We know there's an issue there and it should be dealt with. Now whether or not that gets replaced with stainless or with the extruded something or other, I forget the-- there's other types of metals, that may be decisions that would come at that point in time. That number may have been calculated. I just don't have it with me. I'm sorry.

Q. No, no, that's fair. Other thing I notice from the report which is at Attachment B to Energy Supply, Appendix 1, the report's dated April 12th, 2000, and that, I think, appears to be, when you read the report, that's about the same time that the problem was first noticed, and the report was done probably immediately, and here we are in the 2004 Capital Budget hearing and it's scheduled to be done. So obviously it wasn't done right

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away, it was deferred for a number of years. I'm just wondering if you could explain to me, from the point of view of capital budget process, how it is that this project became a 2004 project and not a 2003 or 2005 project, for that matter, an earlier project?

A. Well that being the case, I guess if we look at how we actually go through the Capital Budget process, that might be helpful, Mr. Young, if I may, and I'll take you--the reference, I do believe is NLH-1, is your key driver on that area. Let me just get myself straightened up here a bit. And from that, I may be able to throw some light onto how we proceed with this. As we run the business and a Capital Budget process is, I look at it as a dynamic exercise. It's ongoing continuously. It's ongoing while we sit here today. There are inspections occurring, there are projects being identified or deficiencies identified. Now, whether that's back to a priority where it fits, that would be based upon engineering judgment and would be based on the judgment of the independent, individual departments. Let me just take you back into the budget process,

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if I may. We start with the energy forecast, customer and energy forecast. That's one of the key drivers. Usually that's produced by the rate's group and so on, and actually it was filed in GRA in this first quarter. From that, we produce then the customer driven accounts, these being the services, meters, extensions and what have you. We also have a look at the system from a load capacity perspective; hence, the Corner Brook transformer, last year it would have been the Virginia transformer and the Fowler's Road transformer, Chamberlains, so that's the second piece of that exercise. On top of that we look at the system from a reliability and what is underperforming within the system, so that's a third block. And finally, we input the system inspections or observations that come through and hence, the field inspections and so on. This is where this one would have turned up. Now out of that then, these are basically brought together, formal process would go probably second quarter and is pulled together at the departmental level within the organization. And it is at those meetings of

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MR. LUDLOW:

the various departmental managers to see where it fits in relation to how do you weigh, for example, the runner at--or the wicket gates at Morris back against the Wesleyville 02. And those are the balances and all while trying to find the balance of the budget, and the request for budget stability, balance with price, safety and environment. And that becomes the challenge as it comes through. So with respect to its level and a priority number, there is no priority number assigned to it, but I would go so far to say that this in pursuit of water use, is water going down a pipe that we're not getting energy out of. The people of this province is not getting the use of that water. That's the general process from beginning to end, bringing in the market, bringing in inspections and what have you.

Q. Do you have any sense of how much--and I know this can be a difficult calculation sometimes, but do you have any sense of how much energy you're losing from this plant?

MR. DELANEY:

A. No, we have no calculation on that.

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Q. Okay, so it's difficult to justify, I guess, if you don't know exactly what you're losing as to how much you'd be saving if you do the work, correct? Now I recognize this is not a large plant.

MR. LUDLOW:

A. I didn't say we don't know what we're losing. I said I don't know what we're losing--excuse me for correcting you.

Q. Well let me put it this way, I don't know what you're losing either, and I don't know if the analysis here provides that.

A. The assessment of this project is based upon the original design that would have been put in place for the Morris development upstream from Mobil. We know they were having trouble and in the past few years getting the output that was designed. There is a lost production factor. I just don't know what it is.

Q. So does that mean when you're running at full gait, you're not getting name plate (phonetic)?

A. That, I would suggest to you, is that--I don't know if that's what it means, but what it means to me is that what we were getting in

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1985/86 at full gait, we're not getting in, say, 2003 at full gait because the wickets are stuck.

Q. So it's an inefficiency problem. But you don't have today for us what that number is -

A. I just don't have it here with me.

Q. - or to make an assessment as to what the loss production is. I'm just wondering, I touched upon this a moment ago, I'm not sure if I got an answer and I know it's another one you may not have at the top of your head, but perhaps you can discuss it in a qualitative sort of way to give the Board and the parties a sense of how this works. There is a difference doing a planned capital job and doing one when absolutely it becomes something has to be repaired. Normally, like planned capital jobs you can time it, you can phase it, you can do other work at the same time, you have crew mobilization advantages, et cetera. I'm just wondering can you give some indication of what that might be for a job like this, just to give us a flavour of it.

A. Job such as Morris?

Q. Well, yes, you know, as opposed to having to

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go in and sort of in the middle of the winter or having to go in at a time when the water is higher and you're spilling more, that sort of thing.

A. Okay, let me try.

Q. Morris might not be a good example for this, I realize.

A. Let me take Chelsea, if we go -

Q. Yes.

A. - and try that one. If we lost the penstock in Chelsea this afternoon, we've got one enormous series of issues to deal with. We have a roadway, we have houses, we have a building. I haven't even mentioned the energy on that end of the business, so if we go in and look at the civil works, the electrical, the mechanical and the civil I would put under the penstock and dam work under it as well. So now you organize and plan when you take your plant out of service. You set your contracts, you project manage, you have one, maybe two project supervisors on site. Now, if I were to run these as three or four separate projects, what I'm into is I'm into mobilization and demobilization, multiples of

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MR. LUDLOW:

supervision, plus the back office planning, scheduling and ordering, that gets all tangled up. When you go now, you do one job. In line work, I would suggest to you that the factors are multiples. Mr. Delaney referenced the line person in the Codroy, a quote was actually made to me and it was sort of an anecdotal comment. When a lineman goes to a job today, he goes to do line work. He do not go to do labour work or stores work or anything else. I want that person in the pole, wrench in hand; that's where he earns his keep. It is not driving back and forth to the job. It is not going to get a nut here or a bolt there, he should be packaged at the pole. That is what creates the productivity. In that case, I would put factors of up to three times as efficient, if not more. So there are multiples.

Q. Just before we leave the Morris project, I have one other question on that. And this is on page 3 of 5, by the way, there's a reference here, Appendix 1. I think this has already been explained. "Since therefore to

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ensure the reliable production of energy from this facility, the equipment must be replaced." I just want to clarify, there is no reliability issues for customers arising out of an outage at this plant, correct?

MR. DELANEY:

A. Which plant are you referring to?

Q. Morris plant, 1100 kilowatt plant.

A. No, there would be no outages to customers as a result of outage to the Morris -

Q. It's a reliability relating to the production from this plant and not in relation to interruptions of power quality.

A. The reliability of the plant itself, the plant producing power.

Q. I guess I just have a couple of more questions about this, just to clarify. This is a fairly young plant. Once this work has been done, do you expect to do much more on this plant in the foreseeable years? I think you had that answer somewhere else which suggests that there isn't an awful lot more forecast here, in this plant, is that right?

A. There is another RFI, I'm not sure if it was asked, but -

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Q. NLH-6, I think it is.

A. NLH-6, which I think indicates, if I get my numbering here, indicates a $50,000. 00 expenditure in 2006 and a $17,000. 00 expenditure in 2007.

Q. I'm just wondering, still on NLH-6, the $50,000.00 in 2006 and the 17 in 2007, I'm assuming they are problems or issues or matters--I won't call them problems or issues if in fact they're not, but they're probably just the future capital requirements in relation to this plant that have been either determined by inspections or by a concern of the useful life of something being known. Is that right? I'm just wondering how those future amounts would have been known at this point and isolated to those figures.

MR. LUDLOW:

A. I don't have the actual detail behind the 17 or the 50, but I will, Mr. Chairman, say very clearly that these plants, by their very nature, will require some level, I'm going to say capitalized maintenance on, I know I use the term "oxymoron" in this every time I say it, but a 20 year old plant that's running

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with moving parts, the only thing I can be guaranteed is something will go wrong with that plant, somewhere down the road. I do not have the details of the 50 or the 17. That could be road work or it might be a building door or something of that type, but it's not substantive that it would be brought to my attention at this point in time. The way we would typically do these, as we did with Chelsea, Mr. Chairman, is to take the future capital stream and any corresponding decrease in operating expense as a result of it and work those back into the pricing model as to how it affects the energy. And that's basically what's been done out over the 25 years back in Chelsea, as an example. And we test those on those types of basis.

Q. Just further on that RFI, there are other amounts for other projects mentioned there, and I'm not asking you to detail any of these, I'm just trying to get a sense of whether some of these might have also fallen into the category, as did Morris, of something that popped up from an inspection and you know you're going to have to deal with others,

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MR. YOUNG:

maybe, of the sort you just referred to. The general mix, I don't know if you can give us any flavour for it, would it contain all of those kinds of issues and all of those kinds of ways of determining capital projects?

(12:20 p.m.)

MR. DELANEY:

A. As we said, we don't have the exact details of every project in front of us, but I can speak at a higher level on some of what's going on here. If we take some of the bigger items through to 2005 onward, for instance the Cape Broyle expenditure, Petty Harbour, up around the 800,000 range, those are projects that we foresee in the future related to upgrading the protection and control systems at the Hydro plants, similar in nature to the protection and control system at the New Chelsea plant. You're dealing with 40 to 50 year old technology that's electrical and mechanical in nature and these two particular projects pertain to the replacement of hydraulic electrical mechanical equipment with digital and electronic equipment as it reaches the end

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of its useful service life, and in many cases, beyond its useful service life. So that's the nature of the bigger ticket items going out into the future.

Q. Just a point of clarification, I wonder if I could refer to NLH-5 for a second and the table that's attached to it. And the question from that--perhaps I can go back to the question--first I'll just read it. How much capital investment has been expended on each of Newfoundland Power's hydro electric generating plants and their associated terminal stations since 1992? And I just want to clarify, the table that's attached would give values which are similar to the general hydro plant facility rehabilitation. That doesn't include all the projects you've done on these plants, is that correct? For example the Lockston penstock is not there?

MR. LUDLOW:

A. That's correct.

Q. So if we were to ask that question, I don't know if we change the wording of the question, but we would need other numbers in relation to the larger projects which you single out for a

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special treatment in those years. Okay.

A. Mr. Chairman, this table presented in NLH-5 is a statement on the project of hydro plant facility rehabilitation and the way we have been presenting to this Board and as we have done today, some of these projects have been rolled up with subcategories within, which is the hydro plant facility rehabilitation being an example, but where there are large projects that requires attention to be brought to bear, such as New Chelsea, the Lockston, Cape Broyle, Horsechops, I can't remember the other ones offhand right now, that would be separate from this table.

Q. So this is not the total amount of expenditures, but it's the total under this category?

A. It's the total under the hydro plant facility rehabilitation project title as presented in the application.

Q. Thank you. They are distinct from refurbishment is the point you're making.

A. Exactly. And, you know, rather than just Petty Harbour itself, this is what's been under this project in Petty Harbour.

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Q. I wonder if I could refer you to NLH-7 for a moment. And the discussion there in relation to Rattling Brook, this is one we discussed to some degree this morning already in direct testimony. I understand there's a job there, a little over $400,000.00 for a generator pre-wind, correct?

MR. DELANEY:

A. That's correct, yes.

Q. Just to put this in context, Rattling Brook, that's in Central Newfoundland, located about where? Flows into the Exploit's, I think, does it not?

A. The Rattling Brook plant is located in Norris Arm in Central Newfoundland.

Q. And as Newfoundland Power plants go, this is a fairly large one, 11.4 megawatts and almost 70 kigawatt hours annually. And I notice the amount of money you stated in annual terms of the value of the energy is roughly three and a half million dollars. I'm just wondering, I think you mentioned that the rewind of the generator that's already failed took about 8 months, is that correct?

A. That's correct, the generator took 8 months to

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MR. DELANEY:

rewind, the one that's already failed.

MR. YOUNG:

Q. Do you have much storage at this plant?

A. Yes, there's a considerable amount of storage at Rattling Brook. I don't have the numbers right off, but it does have storage.

Q. Okay, and the load factor or the capacity factor is around 70 percent, so I assume that often times, but not all the time, one of the two generators could carry the--particularly where you have some storage, one of the two generators could carry the requirements by running that one, essentially flat out, perhaps not its most efficient loading, but you're not spilling an awful lot of water if you have one of the two generators up and running, is that correct?

A. For certain times of the year, we can run the plant with one generator, but that wouldn't be true for parts of the year when we have considerable water, say in the spring, when we would require two generators to produce energy at this plant.

Q. What's the nature of the operation of this

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plant? Is this a plant that is able to generate all the water it gets or is it some inevitable spill?

A. This plant, you know, again I don't have the full history of this plant in front of me, but our experience that I'm familiar with is this can basically use all the water that's available to it.

Q. Did you spill much when you did the other generator? The eight-month period that the other generator is out, do you know if you spilled much water at that time?

A. No, we didn't spill any water--any appreciable amount of water when the generator faulted last year. Now, -

CHAIRMAN:

Q. Did that take in the springtime?

A. It actually faulted right after the spring run off when we hit the dry season. So let's say we were fortunate.

Q. You got lucky.

A. Yeah, well--that it did not occur in the spring or in the tail part of the winter. The fault occurred during--after the spring, so we mobilized, got the rewind work done. It's

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probably--this is a good example of doing work under unanticipated conditions verses planned conditions as well, because the project costs associated with rewinding that generator under the emergency conditions was in the neighbourhood of $650,000, but our estimate here now in terms of doing it in a planned function, rewinding the sister unit, the identical unit, is in the $400,000.00 range.

MR. LUDLOW:

A. Mr. Chairman, I actually was in Rattling Brook when we were coming, pretty well ready to come back on line last December, and it would be, I would put it, might be off by a week, but I would suggest around the 10th to the 15th of December. And I know at that point in time, with the rains that had been coming on, we were pretty much at the top of the dam. And the question was now, if this don't come back, we're spilling water and that becomes the challenge. To carry it over, both January and February and we always get a January thaw anyway, seems to be, and coming through spring, that basically would have spilled water with one unit available. That's where

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MR. LUDLOW:

it would be.

MR. YOUNG:

Q. So you were--well I guess you're never fortunate when a generator needs to be rewound, but you were fortunate in that instance because of the timing, you didn't spill water, as it turned out. I guess the extra cost that hit you which you have just well explained, Mr. Delaney has well explained, was about a quarter of a million dollars of extra cost because it happened at a time that you weren't able to plan it and do it in an orderly fashion. The other numbers in NLH-7 that relate to the amount of money, I mean, I don't know if you can point to any of those numbers in relation to the energy generation from the plant that pertained to a particular out-of-pocket expense that the Company suffered due to loss generation or anything of that nature, is that correct? You know, for example, you're talking about the 1.8 million dollars in annual purchase cost that's saved because you have, you know, one of those units up and running or not.

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MR. LUDLOW:

A. I'm sorry, I'm misplacing, your question is not sinking with me, Mr. Young. If you could try once more for -

Q. Okay, let me try that again. In the third paragraph of the answer to RFI NLH-7, there's a number of dollar values thrown around there. One is the total amount of kigawatt hours and what that relates to in money, so at 69 kigawatt hours a hour, three and a half million dollars, and then you say that the generator that's going to be rewound is responsible for roughly half of that.

A. That's right.

Q. And the arithmetic is done for us there. And you also quoted the dollar figure you're using for energy that shows where the math comes from. But from the point of view of justification, in the generator rewind you did, and I'm not suggesting for a moment that you shouldn't do this on a planned orderly basis, but for the generator rewind you did, you can't demonstrate from these numbers what the real savings are to the customers from doing this rewind on the basis of a planned

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orderly way, verses doing it whenever it fails, which is the alternative which, I suppose, we wouldn't want to choose.

A. Well, Mr. Chairman, running any rotating equipment at the end of a six foot penstock run to failure, there's a big question of engineering judgment and prudent operation has to come into play. And the fact that we ran this at 47 years, you know, that's the reason I'm here today presenting this second winding. We have tested this second winding, we got caught, it failed, effectively is what happened. I've got another unit, same age, same duty cycle, up to this point. The testing is outside the parameters of the new coil, plus plants of similar vintage, is all indicating that we are heading towards eminent failure. So, to shut it down and run the spillage question, that, to me, is not the way to run that plant. We have an installed plant, that's, you know, the--well, that's producing 70 GWhs a year. It's a very valuable asset. That operating expense alone, on that plant, the operating cost of our plants is between .5 and .6. That's the

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operating, not the capital. All in, that would be much, much less. The number, I got it here somewhere, I can dig it out on Rattling Brook, is in comparison to the 5.1 and hence our ability to keep the cost down to our customers. As an engineer, I'll take my executive hat off for a minute, run to failure should not be the premise to operate. It is to find the right time to when you move in, when you don't go in. No one wants to replace equipment early. I certainly don't. I've been challenged an awful lot on that in the past. But I will say running something to the point that it fails and breaks, that's not my way of operating, I'm sorry.

Q. No, and I'm not suggesting it ought to be. I'm just curious on the, just further on that point, I suppose, I notice that the other generator rewind was done in 2002. It wasn't an emergency proposal for 2003, so it's engineering judgment that brings this into 2004, is something which you're trying to avoid, this eminent failure, is that correct?

A. What we have done on that end, Mr. Chairman, is the fact that this was identified, the

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testing is complete, instructions are out to our energy supply department to adjust the duty cycle on this second unit and to bring it in line, where possible, put the pressure on the other unit. That's the type of operating procedures we're trying to get in place to take us over the next year to levelize. It's that kind of balance to carry through. Can we do that? I don't know. But that's what we're going to try to do.

(12:34 p.m.)

Q. Further on the point you just raised. You mentioned about the--you had some readings done and I think the information provided is that the readings didn't provide conclusive proof of an eminent failure, so you supplemented that because of your recent experience with your engineering judgment, is that correct?

A. No question, that is correct, Mr. Chairman. The ultimate testament is a failure and we lost our coils, so what do we do? We then have to try and assess, test through non-destructive means the quality of the installed plant. Now, you take all of that and put it

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MR. LUDLOW:

together and a person or persons, professionals in that field that work with small hydro, aged hydro, you combine that with utility or production standards that are out there of 40 years on the coils. We're already at 47. We put all of that together, hence the decision. It is the judgment basis that comes into this one as well.

MR. YOUNG:

Q. I just wonder if we can, before we leave Rattling Brook, I wonder if we can put it in some context. It's a large, largish plant for a small hydro, 11.5 megawatts. Were one of the units to trip because of this problem in the middle of, you know, running at a time when the energy requirements were fairly high, would that cause, by itself, customer outages or would it likely just be absorbed as a bump?

A. If we were running the plant full out?

Q. Yes.

A. That would be about 11 megawatts -

Q. No, well I'm thinking that you would probably just lose half if one of the generators went, yeah.

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A. If we lose one, we lose say, whatever it is, half of 11, 5.7 I guess, whatever, that, in itself, should not result in lost customer uptime; however, it could have impact on the transmission line reliability in the area, but it would not result in sustained customer outage.

Q. I wonder if I could refer you to NLH-14, this is the New Chelsea protection and control equipment project that I'm interested in at this point, which is a project of, I think, it's just under a million dollars. And one of the, well the second paragraph there, the second full paragraph says, and I'll just read it, "The governor functions reasonably well when operated in parallel with the grid, but does not regulate well when operated in isolation from the grid; therefore the generator is less reliable during emergencies that arise when the transmission system is unavailable." I wonder how often the plant is called upon to serve customers in the New Chelsea area on an isolated basis? Has that occurred many times in the past?

MR. DELANEY:

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A. I don't have the figures in front of me as to how often, but I spent some time out there as manager of that area, in Avalon and I can assure you it happens at least once a year and it may--there may be more than that. What we had done in the New Chelsea area is a radial transmission line that serves two substations: New Chelsea and Old Perlican. And the line, this radial line is in the neighbourhood of 45, 47 years old, so it does require maintenance from time to time. So what we're able to do down there during the summer months is run our New Chelsea and Pittman Pond plants, keep the customers on, keep the power on and take our transmission line out and do some maintenance on it to keep the reliability up on the line. So as to exactly how many times that occurs per year, I'm not sure. It does and it does at least once because I know we've done maintenance on these transmission lines basically annually, and as well, if this transmission line were to fail unexpectedly, the New Chelsea plant would be available to keep power on to the New Chelsea, at least to a portion of the New Chelsea and Old Perlican

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systems, depending on the time of year and what loads were there.

Q. I'm not sure I fully understood your question (sic.). Did you say that you sometimes run these plants for planned maintenance?

A. Yes, we would run the plant, the New Chelsea plant for planned maintenance on a transmission line.

Q. So it avoids having to send, for example, a mobile there in those times. You have the plant, you're up and running and you can use that.

A. Exactly. It would avoid sending a mobile as well as it will enable us to do more work in the amount of time available. If you are able to take the line out of service, de-energize, take the voltage off the line, you can do much more work for the amount of time available as opposed to doing the work during energized conditions. I showed a slide in my presentation of linemen working on a job on a transmission line while it was energized, with all the orange hot line gear. So that's kind of much longer to do the same amount of work. So in New Chelsea that's one of the benefits

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MR. DELANEY:

of having the plant there.

MR. YOUNG:

Q. The protection control equipment that's sought to be replaced though, is it just being justified--I think the answer is no to this, perhaps you can just confirm it, it's not just being justified on the basis of running the system, an isolated basis, correct, this is essentially an added advantage to having it upgraded so that it could run in a stable way, appropriate levels of voltage and frequency when the system is running on an isolated basis.

A. Yes, it is an added advantage. This protection control system is being replaced on the basis that it's 48 years old and it's beyond its useful service life.

Q. NLH 15, I wonder if I could refer you to that and I'm not really sure what the answer means exactly. The question is, "Has there been plant outages caused by the New Chelsea Hydro Plant protection control equipment" and the answer is, "Yes, there's been 92 plant outages, trips and lockouts related to

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protection and control equipment over the last five years." Those 92, would some of those relate to the protection and control equipment operating correctly and isolating the plant in order to avoid a problem that had originated somewhere else, for example, on the transmission grid, or would they all be, essentially, failures of the equipment to operate properly?

A. These would be instances where the equipment did not operate properly. We had problems at the plant caused by the equipment that is installed there to protect and monitor the plant. These are not instances of, you know, the protection operating properly.

Q. Referring now to NLH 16 and the question relates to really customer outages caused by this equipment. My understanding of the answer is that customer outages are not really the problem, it's a power quality issue, is that correct? So you are able, generally speaking, it says no document on instances in recent history, causing customer outages but the concerns are raised and it's in the report about power quality, so it's that level of

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concern, is that right?

A. Yes, exactly. When the New Chelsea plant is required to operate what I would call isolated from the system, and so those instances are when we're doing planned maintenance on the radial transmission line that serves the area or in the event that we lost the radial transmission unexpectedly in a storm, and the New Chelsea plant operates separate from the grid and can provide some limited amount of power to the customers in the New Chelsea/Winterton area up to Old Perlican and Bay de Verde. But there is a problem of power quality when that happens. And the problem is in terms of the frequency, you know, all appliances. The electrical system is supposed to work on 60 hertz and the New Chelsea plant, because of its, you know, its old protection and monitoring system, its old electrical controls has trouble maintaining that 60 hertz cycle while it operates in isolated mode. Of course when New Chelsea is connected to the grid, then the 60 hertz frequency is provided by the grid.

Q. So I suppose if this problem deteriorated

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further, you would have no choice for planned maintenance, but to move a mobile to that site, is that correct?

A. If the -

Q. For example, it's sort of a hypothetical, but if this project wasn't approved and the PLT equipment wasn't changed and you had a planned maintenance situation somewhere down the road, you might be forced to move a mobile generator to that site in order to do that maintenance, which could probably cause you troubles in some other project you may be trying to carry out, is that the level of concern?

A. That would be a level of concern. If we were to determine that, you know, it would be impossible for New Chelsea to provide proper frequency while it operated isolated from the grid, we would in order to--we would have two alternatives; either do the maintenance hot, line of--or three alternatives really; do the maintenance hot while the line is energized; take the power off and have planned scheduled outages for the customers while we did the maintenance; or we could move portable generation. Now that would be after

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determining that New Chelsea could no longer

MR. DELANEY:

supply the local load, supply the proper power (unintelligible) for the local load.

MR. YOUNG:

Q. As I understand the answers to your RFI, the issue we've just been discussing about the way that the plant can operate to revive power in the local areas when isolated, is not the real reason that this protection controls equipment has to be fixed, it's actually a bigger problem isn't it? It's the obsolescence issue, is that correct?

A. That's correct. The justification for the replacement of the protection control at New Chelsea is based on the obsolescence. This is 48 year old equipment. We have protection equipment that's designed to protect the plant that's causing the plant to trip on 92 occasions in the last five years. It's beyond its useful life.

Q. In NLH 17, there's some discussion with some specific information about some problems you're running into, obtaining and maintaining appropriate spare parts. And there's a

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comment there, I'll just read it, the last sentence in the second paragraph, "It is the Newfoundland Power's experience that scavenged parts have very short life expectancy when they are re-installed in an existing governor." I wonder if you can provide a little bit more information about that, if you have a specific example.

A. We got quite a bit of experience with scavenged parts. It's part of, you know, maximizing the asset life of assets, getting maintenance done. Typically, the experience has been very poor. Scavenged parts have short life expectancy because when you think of where did the scavenged part come from, it came from something that was removed from service because it was considered to be obsolete or deteriorated or defective in the first place. So we do a lot of it to get--in terms of, you know, maximizing our asset lives in terms of getting projects pushed out a year or so to equalize and maintain the stability of the capital budget. But the experience with scavenged parts is one of short life expectancy.

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(12:49 p.m.)

MR. LUDLOW:

A. If I could give you an example of--I'll use the term scavenging as an example, I'm not particularly fond of the word but we use this and I'll take it away from the Hydro plant for a minute. Prior to replacement of our SCADA system in 1999 -2000, we almost became a collection point for the old--and I think it was Automatech (phonetic) whatever they are to use, remote terminal users. We would literally go out, buy, piece together, fit and sort of--what I would call the typical way of trying to muck something along to keep it going, keep ti going, keep it going, and it got to the point and a term we've used as well here is that much of it became so obsolete, it became dangerous. You take that back to Hydro plants, one of the other problems we're getting into in scavenged parts, if you can find them, the market by the way is pretty much North America. We deal with Woodward governors, which is here. You got wear and tear already on the scavenged parts. If you machine the parts, getting those tolerances to

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be close to the original design is at best, maybe, and that's the experiences we're getting into. Last year we got into the southern shore with--we were attempting greaseless pins. Well, it was maintenance free for about two years and then they stuck. So now we had to get them all machined. In getting those machined, there's no such thing as maintenance free. I've yet to find a free lunch, Mr. Chairman. And taking that, and then going back in, taking the plants down for multiple--I would--in that case, months and that's subject to check, but if it's two to three month change, repainting them, re-machining them and you still got a second hand piece of equipment. And when I look at a plant like New Chelsea that's been in operation for 40 odd years, 47 years, it's done its service. It was built at a time when it was the key provider for that area by united towns. Next built was Pittman's Pond tied into Heart's Content. Now it's a generator of energy, low cost. Hydro plants by their nature are reliable but they will not be reliable if we put in and maintain it in a

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MR. LUDLOW:

second class rate. That don't mean we need a Cadillac. I need something that's going to run and be there. These controls take into account over voltage for the customer. They talk in terms of equipment protection, which is missing--the term is missing, I had it here a minute ago. Bear with me one second.

MR. MYLES:

Q. NLH 14, Mr. Ludlow?

MR. LUDLOW:

A. The loss of excitation as an example. If we lose the excitation on the generator, thing keep spinning, it heats up, we got our coils gone. So we're right back to square one. So what have we got--if we're going to do this and it is our strong proposal, otherwise I wouldn't have gone before my own Board of Directors and subsequently here, that we have to protect this, protect the investment and protect the supply. Doing that with second hand equipment is not the way to run a professional system. Sorry the speech, but that's again, a philosophy.

MR. YOUNG:

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Q. I notice from your answer in NLH 17 there also seems to be a concern about the compatibility of the older technology and as you explained it, it is fairly old technology. With the other upgrades you're planning to do, so I'm just wondering can you elaborate on that a little bit further.

MR. LUDLOW:

A. As I said earlier, as we look at the detailed engineering and I look at Chelsea as an example, there are seven potential contracts that will be let from this, the bulk of which will go to local people or local Newfoundland companies. Electrical and mechanical, as the tie in between the governor and the governor controls the wicket gates which controls the speed which controls the water flows which controls how fast that turbine spins effectively is what it's doing. And how we tie all that together could be a concern. It's way over my intellectual capacity to get down in too much detail there, Mr. Young, on that one. But what happens--we wouldn't change it simply for the sake of changing it. If we can piece together two technologies and

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make it talk and work, we will. That can cause problems, have caused problems. As a matter of fact there's a project in this budget along that lines at Topsail. When we get to the detail engineering, if there's a part that's good, a part that we can keep, I'll scavenge it for that plant and keep it going, but I want 25 to 30 years out of it. I don't want to be back here in two years recoring or rewinding or redoing the bearings or something because there's a relay that I didn't put in or didn't talk properly. That's the connections between the complexities of technologies.

MR. YOUNG:

Q. Just further on that same project, NLH 18, if I could refer you to that, please. And the response to this question indicates fairly clearly that final design hasn't been done and these numbers are sort of round and rough and we're not sure which of these two types of governors we're likely to choose, is that correct?

MR. DELANEY:

A. Yes, that's correct. There's two alternatives

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we're looking at and like Earl said, this is something we will leave to the detailed engineering as we get into New Chelsea. And the two alternatives are approximately equal in cost. I think one is about 60,000 US and the other is about 70,000.

Q. I gather that there are--at first blush, and I understand these numbers are not final, but at first blush you appear to be favouring the $70,000 proposal even though it's not least cost and it's the other recommendations or these other comments that you're making that favour it that way, is that correct? I just want to get a flavour of what the purpose is because we understand the least cost is generally the rule unless there's a reason not to go least cost.

MR. LUDLOW:

A. Least cost is not cheapest. It's a point I'd like to make clear. And it is very important for everyone to recognize we're dealing with a hydro plant sitting on a former river that has a tail race that's going into Trinity Bay. Now, in looking at least cost versus price, there's a whole bunch of things going to have

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MR. LUDLOW:

to creep in here. We're going to have be talking maintenance, we're going to be talking environment and all those other strange factors, Mr. Chairman, that become very important in that decision. So I certainly wouldn't want to leave the Board with the impression that we're going with a $70,000 US item and not worry about the ten. That's not what this is. The whole piece of this would be taken into account. That governor has 26 gallons of oil in it. Now what value do I put on that 26 gallons of oil. I don't put much on it if I've got it contained and I'm sure that I can control it. But if it loses and gets into the bay, I'm in trouble. And that's the reality of where we have gone in sensitivity. So, sorry, to correct you, Mr. Young, but I it's a point that I think is necessary to be made.

MR. YOUNG:

Q. Okay, I'm not sure I was corrected because I'm not sure we disagree.

MR. LUDLOW:

A. We're finally agreeing.

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Q. Yes. I think the point I was trying to make and I think you've probably spoken to it is that, you know, these costs, as you say, and face value, they're not equal. And I'm not suggesting long term have the same value as we look at here on the page. One is 70, one is 60. And you said--you made a distinction between least cost and cheapest.
A. That's correct.
Q. I think I understand that, and the question I asked, Mr. Ludlow, was whether or not it was these other factors and I think you've just explained some of them, that would lead you to believe that perhaps what appears to be least cost in the long run won't be, and that's the sort of analysis that gets brought to this.
A. I think very well your synopsis of my piece is very well done.
Q. There's no disagreement on some of these points. I'm just wondering, and this is a small point really, but it goes back to the first thing I asked you this morning about the process and the stage in the work where the detailed engineering design will make this decision, just for further clarification on

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that. Right now you have two basic models to work with or two basic approaches you have for this governor. I believe one is sort of the older technology and one is the newer one. And the difference in dollar value is not huge. What sort of factors do you anticipate might swing it when you do the detail design, is that the fine tuning of the numbers or is it something else like an extraneous factor which will become more important?
A. Mr. Chairman, I think it's a combination of both. The way we have traditionally done these, particularly Tors Cove and some of the other plants is it's not a one of anything. We will engineer what our requirements are and we will go to market for that. From there though we learned that--I don't want to say the governor--but specific niche areas within the market has a lot more expertise in this area than probably anyone in our province. So we asked for a given design to be met, a specification, but we also go and ask for alternative options and bring to bear, in the case of this one--let's be hypothetical, Mr. Young, if I may. Let's say we went to

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Woodward governor, I mean what are my other options in today's technology that can mitigate these extraneous factors and can I get them in and down under these layers of dollar, where do they come. So it's a factor of actual cost, what am I getting for the price I'm paying and there could be, I'll use the word extraneous because I used it before, but they're real costs. Oil today is a real issue, particularly if you deal with hydro plants. So putting all that together, the value of that plant, as well in dealing, running remotely in New Chelsea, Hant's Harbour, Old Perlican areas, any governor is going to do that for us. So the combination we do the specifications up front but we would also go to market and ask for those to be verified and checked with alternate options that come back from the marketplace.
Q. I think my last question relates to--we'll have to go to NLH 5 to see it. Just bear with me for a second. Yes, that's where it is, on that table. A few moments ago, Mr. Ludlow, you mentioned that you ordered the oxymoron of capitalized maintenance, as you called it.

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MR. YOUNG:
And when I glance at this table, one number jumps out at me is--well I just don't expect to see a number that small. There's a couple. The one I'll focus on for now is 2001 Cape Broyle, capital investment is $25. And I'm just trying to make some sense of a number that small being deemed capital and how that pops up. What could possibly so small as to be $25 and not be just a routine maintenance issue. Must be US funds. You know, I don't know if this is perhaps a question we should put to Mr. Perry.
A. I'm not even sure I'd put that to Mr. Perry. Sorry, I have no idea what would be a $25 capital expenditure in a hydro plant. I can--you know, we look at these, we follow the rules that have been provided to us under capitalization and offering, you know, the units of property and all those things, tools greater than $1,000 or capital, that one don't fit. I'm running all these in my mind. I don't know. Unless it was a carry over from 2000 and got into a late invoice that was associated with that, that's a possibility,

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that got in 2001.
Q. I said it was my last question, I guess it was my second last. There's a similar issue, although it's a very different dollar value amount, I'm sure, which relates to the radiators on the transformers and I'm not going to turn to it because I don't know if I could find it right off the top. But in one of your projects you're replacing a lot of radiators that you're having significant trouble with and they're treating that as a separate capital project. I'm just curious and please tell me to defer this to another witness if you think it's appropriate for me to do so, but is the radiator different or a piece from the transformer which is separate as a unit of property? I would have thought a radiator is part of the transformer and that that would be under maintenance normally.
(1:04 p.m.)
A. Two things on that front, if I may, assist and I'll probably hand off the detail to Mr. Delaney because I'm getting, pardon the pun, a little rusty on this myself, Mr. Chairman. In the 60s and 70s there were substantive design

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changes went into the radiators on power transformers. Some of them used to be the big pipes that came out. Then in about the early 70s there were crest radiators or the radiators were flat pinned, much, you know, on a large scale, similar to a car radiator in that they were folded and pressed, thin metal. And that was through, say, I'll give it ten years for rough range to get the picture out. In 1980, late '79, '80, it became very evident that we were experiencing rust on these units. You can't grind them very far, obviously because of the very nature. You're extracting heat by blowing cold air through a radiator. In 1980 we changed our standard specifications for power transformer purchase to specify galvanized radiators. So I'll start there. Thirty years ago when we bought these transformers, they had pins on them and we've been maintaining them through, you know, monthly inspections, then we go in every three years and overhaul them. We're in there again in six years to keep them going. The radiators identified are at the end of their useful life. However, without a radiator, a

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transformer is useless. So I have two options. I can get rid of the transformer which to me would be not a prudent activity or alternatively, I can buy a new radiator, galvanized radiator, attach it and extend the life of my asset. And it will extend it quite substantially. And hence the reason we've capitalized those radiators and these would be pre 1980 units. If there's anything you can add -
MR. DELANEY:
A. No. What Earl said, the nature of a radiator is you just can't buy one component of the radiator. And the process we've gone through to repair them is we use sort of a plastic polybond type of thing to plug the leaks and monitor it. So, you know, the manufacturers provide the radiator as a complete package. And these are not small projects, to replace a radiator. We got four in the budget for 2004 in the capital application. They range in prices from 81,000 up to 122,000 and it's a complete component. It will extend the life of the substation transformer. It has an enduring benefit so we consider that a capital

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MR. DELANEY:
expenditure.
MR. YOUNG:
Q. Those are all my questions. Thank you Mr. Ludlow and Delaney.
CHAIRMAN:
Q. Thank you, Mr. Young. Mr. Kennedy?
MR. KENNEDY:
Q. Thank you, Chair. I wonder if we could just deal with one project in particular, I think that might take us close to the hour and a half and that's the New Chelsea project. And the best place to go to is Volume II under "Energy", Appendix II, Attachment A. And there's--this attachment has a number of sort of sub documents and the one I'm looking at first is I think the second one under the-- after the first blue page and it's Appendix A. So it's Volume II, "Energy", Appendix II, Attachment A, Appendix A and it's titled, "Site Assessment Protection and Control." For what will amount to a brief question it was-- the digging to get the document is going to be longer. On page two of that Protection and Control site assessment there's battery plant

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and charger and it's indicated that the batteries are in good condition, that the battery bank was replaced in 1996. Then he goes, "The charger was installed in 1975 and should be replaced due to unavailability of spare part." I guess that sort of triggered off the general question about what the policy is there for Newfoundland Power when considering whether to replace a piece of equipment of this nature. There's no indication there that the charger is not operating in accordance with required specifications. I'm wondering why thought wouldn't have been given to just maintaining the charger despite its age, instead of replacing it at this point?

A. I'm not use to working with a panel, Mr. Kennedy, I'm sorry. Okay, I'll start the answer, if I may. Mr. Chairman, just to give a little overlay, batteries run the power system. The alternating current does not run the power system. All controls, all instrumentation and those, all, that's definitive, but by far, the majority of relays and all of these, what I would call

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intricacies within a power plant or a substation is run on battery power. The reason being, you need it when the power goes out. You got to have some way to bring it back up, hence your batteries. Now, that's an explanation to why there's batteries. Now, we go to the fact that the battery charger is obviously an important part to keep the batteries charged up. Now, this here, we're saying there are no spare parts available, okay. So, if we're going in to complete--we'll keep the batteries, the batteries will stay, the charger, again, if we're going in to do this job which is our proposal, then why would we keep a vital piece of equipment that is no longer repairable, other than by scavenged part or scrounged parts, that does not make a whole lot of sense, to run your system in that way. That's the only point I would make. Do we have a policy on this? This might last another six months, it might last one year, but we know that it is already 28 years old and a battery charger operates 24 hours a day, it's continuously plugged in and running. So, when I leave that plant next

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year, the objective is to have the plant in excellent operating condition. So, I don't have to be back here in 2005, 2008 and 2010 with small--hopefully not $25.00 expenditures, but very low level expenditures back in that plant again. Hence, the reason that we change this point, Mr. Kennedy.

Q. Okay. So, there's no evidence that it's not operating properly?

A. If it was operating properly, we--improperly?

Q. Yes.

A. We would have it pulled out.

Q. Right. So, it is operating properly. The device is doing what it's supposed to do, charging the batteries.

A. Right now, that is correct.

Q. And you keep--I believe I saw that there's in your budget, you keep spare battery chargers on hand, do you not?

A. We do.

Q. I believe you've got four battery chargers in your budget for being purchased this year?

MR. DELANEY:

A. Let me just have a look.

Q. I had the reference and now, of course, that -

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MR. DELANEY:

A. Yes, it's substations, Appendix 2, page 2 of 7 which show the battery chargers that we plan for 2004.

Q. And how many is it?

A. There are three 48-volt battery chargers and two 120-volt battery chargers.

Q. Okay. So do you know which--what battery bank we're dealing with at the New Chelsea plant?

A. Which battery bank?

Q. What size? Is it the 120 or -

A. I'm not sure what that is.

Q. In either event, you would, I assume it would be one or the other?

A. Yes. I would hope, I would think.

Q. So you do have spares on hand in the sense of a spare battery charger on hand that you could use to replace the existing battery charger?

A. The battery chargers that we have in spare are there to provide some degree of security to us that should we have a battery go in any of our--a battery charger go -

Q. Wait now, we're speaking about chargers, yes, okay.

A. - battery charger go in any of our 137

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substations, all of which have battery chargers and 23 hydro plants, all that have at least one or multiple battery chargers. Batteries are something that we pay a lot of attention to in maintenance because as Earl said, when the power is out, the thing that's going to get the power back on is the batteries. A substation or a hydro plant is rendered useless without the batteries if the power is out, of course, right. So, given the contents of the amount of system that we have there, the parts that you're referring to with respect to spare battery charger is to handle the whole system. We frequently, we run tests on our battery chargers every month and those that don't need our specifications are hauled out of the system. We cannot have--particularly in substations--we can't have batter chargers that are not working.

Q. I understand and that's your hypothetical and I believe that Mr. Ludlow indicated if it hadn't been performing according to your requirements, it would have been taken out of service prior to this. So, we know that this charger is working properly up to this point.

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We know that it itself can't be repaired due to the fact that there's an unavailability of spare parts. I guess it begs the question of why not just leave it in service, let it live out its useful life and in the event that it does fail, you've got back ups on hand to replace it with already, so that there wouldn't even be any, presumably, delay in delivery.

MR. LUDLOW:

A. These spares are not--all that equipment is not simply sitting on a warehouse shelf waiting to be used. I think that's a point of clarification for this Board. This is a continuous rotating inventory. As we check these battery banks, check these--what do you call them--the chargers, we may, in fact, use these very quickly. I do not have a spare one sitting there waiting to be used, okay. It is that type of an inventory spare. If I took out the one out of Chelsea, as an example, that I know is 28 years old, would I put it spare? No, I would not. That is not--if it is operating today, the future viability of that unit is at best, suspect.

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So, again, I come back -

Q. Only because of its age though?

A. Well, I can't get parts, there's something wrong with it. It's 28 years old, obviously the market didn't give up making them, Mr. Chairman, simply because they are a great product. Okay. So, let's be realistic in that too. This stuff do wear out. So, if, in fact, that battery charger fails after that type of in-service life, my objective should be and is not to run it to failure because now, all of a sudden, I'm losing that equipment, I'm dispatching people and I'm again running my plant to breakdown. That do not make operating logic.

Q. Well, a failure of your battery charger won't cause breakdown of your plant though, correct?

MR. DELANEY:

A. You won't know that until, if you had an outage and you tried to bring your plant back up, then you find out if your battery charger is not operating properly.

Q. Yes, but your batteries would be charged at that point or if they weren't, you would have realized that. If your batteries weren't

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MR. KENNEDY:

charging, you would have gotten knowledge of that prior to your plant shutting down, correct?

MR. LUDLOW:

A. Possibly.

MR. DELANEY:

A. Not necessarily.

MR. LUDLOW:

A. This whole area of the battery charger, it is an insurance blanket that keeps your batteries running. That's what it boils down to, okay, in this case. The battery charger here, to boil this down, I have a 28-year old piece of equipment, it is functioning today, if it break tomorrow, I don't have any alternative, but to replace it. Would I challenge my two spares to put it into that, if I move this one and put that--I put another one in spares, then I'd be comfortable, then I would run comfortable not from being overly rich, leave that one there and give me another one for spares because I need those two spares to run my 138 substations and 23 hydro plants.

Q. One of which is New Chelsea?

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MR. LUDLOW:
A. Okay, well 22 hydro plants.
Q. If we could just go onto the next section, actually a few sections away, it's Appendix C under the same division that we're looking at, Civil Work Site Assessment. And this is a discussion about the condition of the woodstave, penstock and the steel penstock at New Chelsea. And over on page three in your concluding paragraph, it reads, "in conclusion, the woodstave, penstock has passed its reliable service life and needs to be replaced. It would have been expected that the steel penstock would be good for another 20 to 25 years, however, investigations reveal that the steel section has also deteriorated to a condition where it must be replaced before reliability or failure become an issue. Based on the above, the entire penstock should be replaced in the next year".

Now, if we look at the next document, however, Appendix B which is the steel penstock assessment, the second page of that memorandum from Gary Murray to Gary Humby dated June 16 of this year. And the third and

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second last paragraphs that I want to read from, third last paragraph on page two reads, "in conclusion the internal and external inspection of the penstock revealed that the penstock is severely corroded and the thickness is below the design requirements. The deterioration of the pipes seems to be more from the internal corrosion rather than the external corrosion". It continues, "the penstock may very well be pitted completely through and leaking in some areas with pressure rises in the pipe from normal and emergency shutdowns at the plant. Penstock leakage and resulting erosion of the bedding material could become problems into the future. While failure of the pipe is not a concern at this particular time, the penstock has passed its reliable service and should be replaced in the near future". I wonder if you could just comment on that first. I have another question concerning this, but I guess from a lay perspective, there seems to be almost like a contradiction within that last statement I read, "while a failure of the pipe is not a concern at this particular time, the

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penstock has passed its reliable service life", so how could the penstock have passed its reliable service life if there's no failure of a concern at that point in time?
MR. DELANEY:
A. Okay, then sentence is what it is in terms of the report, failure, but if I look at the context of the whole e-mail, I think it would be important--if we go back and look at what we actually did find in terms of the steel penstock and the measurements that we did were determined through ultrasonic testing. We did a number of pit holes along with steel penstock. Much of the penstock is actually buried. And we found places in the penstock where there was heavy pitting and wall thicknesses from 3 to 10 millimetres. Now, 3 millimetre wall thickness is well below the original 10 millimetre wall thickness that this pipe was designed for. And the average thickness--and I'm just picking up from the fourth paragraph in the first part of the e-mail, the average thickness reading in the section below the manhole was 5.74 millimetres and 4.43 millimetres above the manhole with

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MR. DELANEY:
the average of all the measurements being 5.09 millimetres. So, we're dealing with a pipe, a penstock steel pipe that has a wall thickness half of its original design. Now -
Q. If I could just interrupt you for a moment, I think if you read though the next two sentences out, it actually says, the number should not be interpreted as saying that only half of the wall thickness is remaining.
A. Okay, for the entire section of the pipe, I would assume that to be. I think if we look at the context of the e-mail in total and weave through the entire thing, we'll be left with the impression that this is a good project for 2004. And as a matter of fact, he does--let me just read it here for a second. The recommendation from the engineers is replacement of penstock in the near future.
Q. The feasibility study that follows again after that document, that Appendix E indicates that the replacement cost for this steel portion of the penstock is half a million dollars. However, it's also indicated that the penstock maintenance accounts for significant portions

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of the operating cost and the future costs after this penstock portion has been replaced would be reduced by $5,000.00 a year. So, we're going to reduce the operating maintenance by $5,000.00 a year with a half a million dollar capital expenditure.

A. This project is not being justified on the basis of the operating cost reduction.

Q. Well, I thought that's what the feasibility analysis was attempting to show, is that there's a net present value, if you will, to the project overall, but I'm just dealing with the penstock, the steel penstock itself.

MR. LUDLOW:

A. There's a couple of things happened here. First of all, I will speak to the steel, if I may, for a second and tie it back to what you were referring to, Mr. Kennedy. Mr. Chairman, when Mr. Murray investigated this penstock, with two things on mind, we've had a significant blowout of this pipeline, and actually while I was on the stand here last year, I actually was speaking in terms of Lockston and then we had one, I think it was November on the woodstave penstock at Chelsea

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that took a month to repair. The question that was being addressed regarding the reliability of the steel penstock here is the general condition. It's 48 years old, if this was pressing imminent rupture, that plant would be shut down today.

Q. Are we dealing with the wood penstock or this steel penstock?

A. I've gone to the steel now and I'm coming back to the others. We have not had a rupture in the steel, but the upstream wood has been one thing. As we investigated the steel and in the e-mail or the memo forwarded from Mr. Gary Murray to Mr. Gary Humby, both of which are professional civil engineers, well experienced in small hydro, they were asked to investigate the integrity of the steel. His reference, as I would interpret it, Mr. Kennedy, in your reference that there's no--where's it to there, just bear with me one second--"a failure of the pipe is not a concern at this particular time", that's the reference. I would hope not. At this particular time, if that was in failure, that plant would no longer be generating kilowatt hours and that's

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the first test that he will use. However, his assessment based on the findings and its pitting, I think, is the reference that they're doing, rather than the whole circumference, circumferential assessment, there is substantive pitting on the interior and hence at that state. Back to the Appendix E, its feasibility analysis, the feasibility analysis was put together to see whether or not this project passed a future life of this plant as we move out for another 25 years, I believe that's the number, over the span. And it should include all capital flows into the plant. You'll find a power transformer in there at some point, possibly 2010, 2015, wait, transformer, 2024, I'm sorry. So, this feasibility analysis was done on the premise that it tested the future viability of this plant back against where we are today. Included in that is the capital investment as well as any reduced operating expense that could be determine. The two are not directly linked between 500,000 capital and 5,000 operating expense reduction.

Q. Mr. Ludlow, I don't see any discussion in any

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MR. KENNEDY:

of this portion of planned refurbishment proposal on what alternative Newfoundland Power looked at as opposed to replacing some of the this equipment like the steel penstock. There's not discussion in the documentation about reviewing whether it made more sense to just continue maintaining that steel penstock for a time or whether repairs were possible to the steel penstock as opposed to fully replacing the steel penstock?

A. That's fair.

Q. Did Newfoundland Power consider those alternatives? And if so, why wasn't it included in the refurbishment report?

A. The answer to your first question, the first question, Mr. Chair, is yes, they have been considered. With 20,000 plugs in this penstock already -

MR. YOUNG:

Q. In the steel one?

A. No, this would be in the woodstave. The way they repair a leak is to use plugs to find plugs. I'm not sure what the right term is, but the term I use, they plim up and that

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means basically they swell up with the water and they seal. Plus the frequency of the blowouts that have been experienced on the wood section, so that has been assessed. It's the end of useful life, we cannot treat the wood, Penta is not a friendly item to use. I don't even know if you can get Penta, that's what traditionally has been used, tars and those type of wood preservatives on a woodstave pipes.

Now, with respect to the underground section of the steel, based upon what I have been provided by my professional staff, it is 47 years old, there is substantive pitting occurring and has occurred on the test fronts. The time is right now to do this. It is outside, it is 47--I don't have to repeat that--47 years old. Can we get a year? It makes no sense to split the project between two and the also I am not, upon his recommendation, willing to push this any further than we've already pushed it. That's the type of feel that I get across from it. Why it's not in a report, I can't tell you, sir, but I do know that before we go with

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this, we will assess steel, fibre and other alternatives that the market can bring to bear, whether it will be steel and wood, or will it be all wood or all steel, that I don't know because we have not completed the detailed engineering civil works on this project at this point.

Q. Thank you, Mr. Ludlow. Chair, that's a good place to stop for today, I think, we were scheduled to stop at 1:30. I have--there's enough material that we really need to call the panel back for tomorrow.

CHAIRMAN:

Q. Okay, thank you, Mr. Kennedy and I think as we indicated earlier, we'll reconvene tomorrow morning at 9:00 as opposed to 9:30. Thank you.

MR. KENNEDY:

Q. Thank you, Mr. Chairman.

Adjourned at 1:30.

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CERTIFICATE

I, Judy Moss Lauzon, hereby certify that the foregoing is a true and correct transcript in the matter of Newfoundland Power's 2004 Capital Budget Application, heard before the Board of Commissioners of Public Utilities, Prince Charles Building, St. John's, Newfoundland and Labrador on the 10th day of September, A.D., 2003 and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 10th day of September, A.D., 2003

Judy Moss Lauzon