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1 (9:32 a.m.) 2 CHAIRPERSON: 3 Q. Good morning, ladies and gentlemen. I think 4 as Jim Furlong at NTV would say, it seems like 5 only yesterday, you know. This hearing of the 6 Public Utilities Board is convened this 7 morning in the matter of an application by 8 Newfoundland Power for approval of its 2004 9 Capital Budget, as well as application for an 10 order of the Board for the purpose of fixing 11 and determining Newfoundland Power's average 12 rate base for the year 2002. 13 For the purpose of the record, at this 14 time I'll introduce the panel. My name is 15 William Finn and I have been delegated to 16 chair this particular panel. Sitting with me, 17 to my right is Commissioner Gerard Martin and 18 to my left, Commissioner Don Powell. The 19 Board will be assisted by several staff 20 members throughout the hearing. To my 21 immediate left is Ms. Cheryl Blundon, Board 22 Secretary, Ms. Dwanda Newman, Board Solicitor, 23 and Mr. Mark Kennedy, who will act as Board 24 Hearing Counsel. I'd like to ask Ms. Newman, 25 at this time, if she would indicate and	1 confirm, for the record, all appropriate 2 matters preliminary to the commencement of the 3 hearing, please. 4 MS. NEWMAN: 5 Q. Yes, good morning, Chair and Commissioners and 6 other people in the room. I can confirm that 7 an application was received on July 25th, 2003 8 from Newfoundland Power for, as you said, 9 approval of their Capital Budget and their 10 rate base. This application was amended on 11 September 5th, 2003. They did also file some 12 pre-filed evidence and several revisions were 13 filed to that evidence late, I believe, as 14 even this morning. 15 I can confirm that the Board published 16 notice of the application and also this 17 hearing date on its website first on August 18 1st and in several local papers on August 5th. 19 The papers that it was published in include 20 The Evening Telegram, The Western Star, The 21 Shoreline, The Express, The Compass, The 22 Packet, The Southern Gazette, The Beacon, The 23 Pilot, The Advertiser, The Nor'wester, The 24 Coaster, The Humber Log, The Georgian, The 25 Gulf News, The Labradorian, The Charter and
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1 The Northern Pen. I can therefore confirm for 2 the Panel and those in the room that this 3 matter is duly constituted. 4 We did receive, we being the Board, did 5 receive an intervention from one party, which 6 is Newfoundland and Labrador Hydro, and no 7 other interventions were received. The Board 8 did not receive any letters of comment, did 9 not receive any requests to make oral 10 presentations. There was some requests for 11 information issued and I understand that they 12 have all now been answered by the utility, so 13 that matter is finished. The Board did not 14 require electronic filing in this matter and 15 therefore we will not be having our electronic 16 system operating the length of this 17 proceeding, although I do understand that the 18 monitors will be in use this morning for a 19 short presentation. 20 The sitting times for this hearing that I 21 propose are from 9:00 a.m. to 1:30, note this 22 morning, being the first day, we didn't start 23 until 9:30, but tomorrow morning will be a 24 9:00 a.m. start proceeding until 1:30, with a 25 half an hour break from 11 to 11:30. I	1 MS. NEWMAN: 2 understand the parties are willing to sit late 3 on any day, if it is deemed to be appropriate 4 in the circumstances, and that's fine with the 5 Board. 6 Also, I would note that these matters are 7 being transcribed, recorded and transcribed 8 and as per the usual course of events, I 9 believe that the transcripts will be available 10 electronically in the evening of the day of 11 the proceeding and in hard copy the next 12 morning. Of course, if we sit late, then that 13 might impact upon the schedule, but I have 14 ultimate faith that the transcriber will do 15 their best to get it to us as soon as 16 possible, in the event that we do sit late. 17 I should also note that there's been one 18 information request filed by the Board, and 19 that is a letter from Grant Thornton, and 20 that's Information Number 1. I have also 21 circulated rules of procedure that I propose 22 be used and respected in this proceeding, in 23 addition to those set out in the Regulations 24 39 96. The rules were circulated by the 25 parties, to the parties and I understand that

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1 they are in agreement with the same and I 2 therefore propose that the Board adopt those 3 rules in this proceeding. 4 Finally, I understand that Newfoundland 5 Power does have one matter, one procedural 6 matter that they want to address in terms of a 7 filing, before we start here this morning. 8 CHAIRPERSON: 9 Q. Thank you. The Board will adopt the rules as 10 circulated and perhaps at this time, I would 11 ask the parties to introduce themselves, 12 beginning with the applicant. 13 MR. MYLES: 14 Q. Good morning, Chairman Finn, Commissioner 15 Powell, Commissioner Martin. My name is Brock 16 Myles and beside me is Gerard Hayes. We are 17 counsel to Newfoundland Power on its 18 application before the Board today. I have an 19 opening statement and I'll proceed with that. 20 There are two parts to the application, 21 the first seeking the Board's approval, 22 pursuant to Section 41 of The Public Utilities 23 Act, of Newfoundland Power's 2004 Capital 24 Budget of \$53,909,000. The second part of the 25 application, pursuant to Section 78 of The	1 Act, asks the Board to fix and determine 2 Newfoundland Power's average rate base for the 3 year 2002 at \$573,337,000. 4 As noted, the record of the application 5 commenced with the initial four volumes, which 6 were filed with the Board in July. Volume 1 7 contains the application itself, including 8 four supporting schedules. Schedule A 9 provides a summary of the 2004 Capital Budget. 10 Schedule B contains a breakdown of the Budget 11 categories and the projects in each category, 12 as well as individual project descriptions. 13 Schedule C sets out those projects for which 14 there is a committed carryover into future 15 years, of which, in fact, there's only one, 16 which is the final payment in 2005 for the 17 purchase of the Aliant poles. Schedule D sets 18 out the calculation of Newfoundland Power's 19 average rate base for the year 2002, which the 20 Company is requesting the Board to fix and 21 determine. To assist the Board, Schedule D 22 also sets out the calculation of Newfoundland 23 Power's average rate base for the year 2001, 24 which was fixed and determined by the Board 25 pursuant to Order No. P.U.36 (2002/2003).
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1 Volume 1 of the materials also contains 2 four reports that Newfoundland Power was 3 required to file with this application, 4 pursuant to either of Order No. P.U.36 5 (2002/2003) or Order No. P.U.19 (2003). I'll 6 just review those reports quickly. 7 The first is the 2003 Capital 8 Expenditures Status Report. Now, Ms. Newman 9 advised you there is an Exhibit. It is a 10 update of the variances shown from May 31st, 11 2003 to July 31st, 2003, and Mr. Delaney will 12 be speaking to the updated information, as 13 well as the Status Report itself, and I would 14 propose that this updated variance be entered 15 as Exhibit PJD-1. 16 The second report in the information is 17 the Information Technology Strategy Report 18 2004-2008, and the second panel, comprised of 19 Mr. Mulcahy and Mr. Collins, will address this 20 report. The third report is the 2004 Capital 21 Budget Plan and it will be addressed by Mr. 22 Ludlow. 23 Finally, the fourth report is the Changes 24 and Deferred Charges 2003-2004, which was 25 ordered to be filed by the Board with this	1 MS. NEWMAN: 2 Capital Budget application in Order P.U. 19 3 (2003) which was the General Rate Order, and 4 this report will be addressed by Mr. Perry. 5 Also contained in Volume 1 is pre-filed 6 testimony of the three witness panels. 7 Volumes 2, 3, 4 contain supporting 8 material for certain of the Capital Budget 9 projects, being comprised largely of more 10 detailed descriptions and reports. And then, 11 as noted this morning, in addition to the 12 material filed with the application and the 13 subsequent revisions, there have been 14 approximately 282 requests for information 15 filed and responded to, and of course, the 16 RFIs and responses will form a part of the 17 record. 18 With respect to the witnesses, the pre- 19 filed testimony in support of today's 20 application has been provided by three panels 21 of witnesses who are here today and who will 22 be examined in chief by myself and then be 23 available for cross-examination by other 24 counsel and, of course, by the Board. Mr. 25 Ludlow, Mr. Earl Ludlow and Mr. Phonse Delaney

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1 will address the 2004 Capital Budget, with the 2 exception of the Information Systems category. 3 Mr. Ludlow and Mr. Delaney will also address 4 the 2003 Capital Expenditure Status Report and 5 the Capital Budget Plan. 6 The second panel is Mr. Michael Mulcahy 7 and Mr. Peter Collins, who will address the 8 Information Systems projects in the 2004 9 Capital Budget, as well as the IT Strategy 10 Report and the results of the Customer Service 11 Replacement Study, including the issue 12 relating to open BNS operating systems, which 13 have been previously identified to this Board. 14 The third and final panel is comprised of 15 Mr. Barry Perry and Ms. Lisa Hutchens, who 16 will address the 2004 Average Rate Base, the 17 Changes and Deferred Charges Report and the 18 matter of financing the proposed capital 19 expenditures. 20 Mr. Chairman, as well, I'd like to 21 introduce to you Ms. Colleen Comden, who will 22 be running our system during Mr. Ludlow and 23 Mr. Delaney's presentation. However, we have 24 the entire record on electronic copy, and so 25 we would be in a position to refer to the	1 documents as we go, if that's--we are 2 actually, in fact, planning on doing that, so 3 if that's acceptable to the Board, Ms. Comden 4 will be available to move to the documents as 5 they are referred to. 6 CHAIRPERSON: 7 Q. That's fine, certainly. 8 MR. MYLES: 9 Q. Mr. Chairman, unless you or either of the 10 Commissioners have any questions, the first 11 panel is now prepared to commence their 12 examination-in-chief, which includes, as it 13 has in the past, the Power Point presentation. 14 CHAIRPERSON: 15 Q. Thank you. Perhaps, for the record, I'll ask 16 initially counsel for Hydro to introduce 17 himself, for the record. 18 MR. YOUNG: 19 Q. Thank you, Mr. Chair, members of the Board. 20 My name is Geoff Young. I'm counsel for the 21 intervenor, Newfoundland and Labrador Hydro. 22 Mr. Chairman, it may be--I have a brief 23 opening statement also. This may be as soon a 24 time as any. 25 CHAIRPERSON:
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1 Q. Certainly. 2 MR. YOUNG: 3 Q. Like Hydro's intervention in Newfoundland 4 Power's 2003 Capital Budget hearing, our 5 intervention in the present matter is largely 6 driven by and directed to issues of policy and 7 procedure regarding the regulation of the 8 capital budgets of public utilities by this 9 Board. The Order of this Board arising from 10 last year's hearing, P.U. No. 36 (2002/2003), 11 contained a Schedule C, which set out the 12 conditions for future filings to be adhered to 13 by Newfoundland Power. The same conditions 14 apply to Hydro and decisions and Board 15 policies that are made or formed in the 16 regulation of Newfoundland Power's Capital 17 Budget can be expected to have an effect upon 18 the regulation of Hydro and its own Capital 19 Budget process. 20 In this matter, Hydro is asked 89 21 information requests and will be conducting 22 cross-examination of some of Newfoundland 23 Power's witnesses, probably not all of them. 24 Hydro will not be calling any direct evidence. 25 The cross-examination, though intended	1 MR. YOUNG: 2 primarily to deal with issues of regulatory 3 policy, as opposed to challenging the prudence 4 or the appropriateness of specific projects, 5 will inevitably deal with the details of the 6 application and supporting documentation, 7 because, in our view, it is not terribly 8 useful to deal with these matters totally in 9 the abstract. It is hoped that the questions 10 that Hydro raised in the request for 11 information and it will raise in cross- 12 examination will illuminate some of the issues 13 referred to before and that the facts that 14 arise in the present matter will come forward 15 and will be of assistance to the Board. Thank 16 you. 17 CHAIRPERSON: 18 Q. Fine. Thank you, Mr. Young. Mr. Myles. 19 MR. MYLES: 20 Q. Thank you, Mr. Chairman. Mr. Ludlow, are you 21 a professional engineer and vice-president of 22 engineering and operations with Newfoundland 23 Power? 24 MR. LUDLOW: 25 A. Yes, I am.

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1 Q. I'm sorry, it just struck me, the witnesses 2 need to be sworn. 3 CHAIRPERSON: 4 Q. Good thing somebody's thinking. 5 MR. EARL LUDLOW, SWORN 6 MR. PHONSE DELANEY, SWORN 7 CHAIRPERSON: 8 Q. Mr. Myles. 9 MR. MYLES: 10 Q. Thank you, Mr. Chairman. Mr. Ludlow, are you 11 a professional engineer and vice-president of 12 engineering and operations with Newfoundland 13 Power? 14 MR. LUDLOW: 15 A. Yes, I am. 16 Q. And you have prepared pre-filed testimony in 17 the exhibits. Do you adopt these as part of 18 your sworn testimony today? 19 A. Yes, I do. 20 Q. Mr. Delaney, are you a professional engineer 21 and manager of the western region with 22 Newfoundland Power? 23 (9:47 a.m.) 24 MR. DELANEY: 25 A. Yes, I am.	1 Q. And you have prepared pre-filed testimony in 2 the exhibits. Do you adopt these as part of 3 your sworn testimony today? 4 MR. DELANEY: 5 A. Yes, I do. 6 Q. Mr. Ludlow, what will be your focus today? 7 MR. LUDLOW: 8 A. Good morning, Mr. Chairman and fellow 9 Commissioners. Today, I propose to use, as 10 counsel suggested earlier, a Power Point 11 presentation to provide the Board with an 12 overview of our 2004 Capital Budget 13 application and the details contained therein. 14 First, I will provide the Board with a high- 15 level general overview of Newfoundland Power 16 and the provincial electrical system. And 17 secondly, I will present the 2004 Capital 18 Plan, and this was filed as part of the 19 application. From there, I will pass along to 20 Mr. Delaney, who will take you through the 21 2003 Capital Budget Variance and the specifics 22 of the 2004 Capital Budget application. That 23 is, with the exception of the Information 24 Systems section and that will be dealt with by 25 a later panel.
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1 MR. MYLES: 2 Q. Mr. Ludlow, in your prepared pre-filed 3 testimony, at pages two to five, you provide a 4 general overview of the 2004 Capital Budget. 5 What highlights do you want to give to the 6 Board today? 7 MR. LUDLOW: 8 A. Well, first of all, I'd like to start, and 9 this is a standard chart that I've been using 10 now for probably four or five years, but never 11 hurts to bring it back up, I guess. What I 12 have presented on the screen or in the screen 13 in front of you is the service territory 14 serviced by Newfoundland Power on the island 15 portion of our province. It's important to 16 note that this is clearly representative of a 17 combination of rural and urban customers. As 18 you can see by the orange or brown area on the 19 chart, we service mainly from the southwest 20 coast through the Port au Port up to Corner 21 Brook, parts of the Baie Verte, cross into 22 Central, Grand Falls-Windsor, Twillingate, 23 Bonavista North, Burin, Bonavista Peninsulas 24 and pretty much--well, not pretty much, all of 25 the Avalon Peninsula. The areas not serviced	1 MR. LUDLOW: 2 would include the Great Northern, again parts 3 of the Baie Verte, Fogo Island, and there's a 4 couple of areas not quite clear here and they 5 would include St. Brendan's, Monkstown, and 6 indeed, also on the south coast, the area of 7 the Conaigre Peninsula, as well as, I guess, 8 the areas over as far as Franchois and those 9 areas on the south coast. 10 Also included on this map is it 11 represents--the dots represent the locations 12 of where we have staff and equipment 13 positioned throughout the province. This is 14 not a--the size of the dot is not indicative 15 of the relative number of staff or crews we 16 have. This would range from St. John's, where 17 we would have by far the bulk of our technical 18 and line, as well as vehicular resources, 19 through to the other extreme, being Baie 20 Verte, where we would have one person and a 21 truck. So each of these basically have been 22 designed and are continually monitored to 23 provide new services, response to trouble, and 24 indeed, what we've tried to do here is to 25 position ourselves to respond to trouble calls

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1 and the like in a two-hour time frame, and 2 that's the basis upon which we've been 3 operating, and we try to run that consistently 4 across all areas. 5 Q. Mr. Ludlow, could you please advise the Board 6 what the main drivers are behind the 2004 7 Capital Budget of \$53,900,000? 8 A. Our capital investments are driven by our 9 commitment to meet customers' expectations for 10 safe, reliable and low-cost electrical 11 service. Therefore, the main drivers for this 12 \$53.9 million capital budget are reliability, 13 safety, customer service, productivity and the 14 environment. This is pretty much consistent 15 with the previous capital budgets that I have 16 addressed before this Board. Capital 17 expenditures play a key role, indeed a vital 18 role, in our ability to serve our customers. 19 Q. Mr. Ludlow, what does this slide show? 20 A. What you have in front of you here is a slide 21 presenting the entire electrical system at a 22 transmission and a generation level within the 23 island portion of the province, and I use this 24 purely to give a flavour of, I guess, the 25 scope. An electrical system is made up of	1 four distinct components. They would be 2 generation, transmission, substations and 3 distribution. Now it's clear, and I bring the 4 Board's attention that this is not 5 representative of Newfoundland Power's system. 6 This is the electrical system. On the island 7 portion, there's Newfoundland and Labrador 8 Hydro who would run the bulk transmitters, as 9 well as the Great Northern and the points I 10 did before, as well as the major generators. 11 We have Abitibi Consolidated and we have Deer 12 Lake Power, and we also have Newfoundland 13 Power, and that's basically a representation 14 of a mix of all these. 15 The utility industry is very capital 16 intensive. Reliable service requires 17 significant investment in plants. Now put 18 this in perspective. At Newfoundland Power, 19 we have spent approximately one billion 20 dollars to build our electrical system, and to 21 further size this for you, Commissioners, this 22 represents: in excess of 10,000 kilometres of 23 lines, be it transmission or distribution; in 24 excess of a quarter--sorry, quarter million 25 poles, 250,000 poles. We have 137 substations
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1 within this island and 23 small hydro plants. 2 So that will give you a flavour of the breadth 3 and scope of what we're dealing with here. 4 And that's in place to serve approximately 5 220,000 customers and they are residing in 6 over 600 communities on the island portion of 7 Newfoundland and Labrador, and that represents 8 approximately 85 percent of the electrical 9 customers, electrical service customers in our 10 province. 11 Now when you stop and think about the 12 size, the nature and the geography of our 13 system, it is not difficult to understand the 14 continued and ongoing investment that is 15 required to keep this thing running. Combine 16 that with the economics and that the growth is 17 not always uniform across our service 18 territory, we take our obligation to serve our 19 customers very seriously. We must continue to 20 invest in rural Newfoundland, despite the 21 significant out migration that has been spoken 22 at here in the GRA and in other hearings, 23 while at the same time meeting the growth 24 requirements in areas such as St. John's, 25 Northeast Avalon, and also in places like	1 MR. LUDLOW: 2 Corner Brook, and we're seeing some growth in 3 that area now. 4 Now the quality and condition of the 5 infrastructure on the island is vital for our 6 ability to provide quality service, balanced 7 with the lowest reasonable cost. A sound 8 electrical system is increasingly important in 9 today's technologically dependent economy. 10 It's interesting, twenty odd years ago when I 11 joined the utility, you go to a fish plant and 12 you'd see splitting lines. Today you go, you 13 see microprocessor based conveyor belts. 14 You're seeing microwave thawing of fish 15 product. You can go to the lumber mills, 16 you'd find the same thing, the electronics, 17 and it's that state of technology has 18 ingressed throughout the service territory. 19 That's at that end. You go to medical 20 technology. Today you hear about the MRIs and 21 the dialysis units being brought into more 22 diverse centres than one major centre. It's 23 all dependent. And finally, go to home and 24 business computers. Sustained quality service 25 is vital because today, the home in my

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1 hometown on Fogo Island, for example, is just 2 as important that it's connected to the world 3 economy, as it would be in downtown St. 4 John's. So hence, it's the reliability that 5 becomes important throughout this 6 presentation. 7 Q. Could you provide general comments on the 2004 8 Capital Budget, Mr. Ludlow? 9 A. Approximately 56 percent or \$30 million will 10 be used for replacement and upgrading of older 11 assets within our electrical system. This 12 represents the proactive replacement of 13 deteriorated or inefficient equipment and 14 plant. Keeping in mind, Mr. Commissioners, 15 that the replacement today is much more 16 expensive than the original investment cost, 17 due to inflation. These assets, many of them 18 are thirty to forty years old. 19 A second category of new capital 20 investment, largely for new growth areas, 21 totals approximately 22 percent or \$12 22 million. These are in place, or this 23 allotment is there to add new customers, new 24 services, and also for the addition of load 25 capacity. As the system creeps at one to two	1 percent growth, the capacity must be added to 2 carry it. 3 The third section I'd reference is that 4 of technology investments, representing seven 5 percent or approximately \$3.9 million of the 6 budget. This level of investment is needed to 7 support the electrical system and the 8 processes required in the general operation of 9 the business. Technology is also necessary to 10 achieve productivity improvements and to 11 sustain gains made to date in operational 12 efficiency that will ultimately benefit all 13 customers. An investment in technology is at 14 the core of our interaction with our customers 15 and is required to meet their changing level 16 of expectations for flexible and more 17 convenient ways of doing business with us. 18 Q. Mr. Ludlow, can you refer to the Capital Plan 19 and provide the Board with an overview of the 20 historical capital expenditures at 21 Newfoundland Power? 22 A. The Capital Plan is contained in Volume 1 of 23 the filing, and if I could draw the Board's 24 attention to the graphic that is contained on 25 page three of the plan and is also
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1 represented, reproduced here on the screen. 2 We see a representation of the historical 3 capital expenditures from 1988 to present. We 4 took it back to 1988 to give a flavour of--to 5 provide a realistic comparison over the time 6 period. So--figure out how to use this thing 7 now, I got technology. Here we go. So right 8 here, you can see up to around this point, and 9 I'm just flowing through, one thing I'd point 10 to the Board is in the graphic in front of 11 you, as well as on page three, we have shown 12 the Aliant pole purchase separately. You can 13 add them together and get the--you can pick it 14 out in the graphs. That's the--what's the 15 point I'm trying--we've pulled it out and 16 highlighted it separately, I guess. 17 Since 1988, capital expenditures have 18 ranged from a high of 67 million in 1990 to 29 19 million in 1996. We can all go back to 1992 20 when the cod moratorium hit, and that was 21 indeed a time of unprecedented uncertainty in 22 the Newfoundland economy. And if you look 23 here, so we're in this range, for the next 24 four to five years, we were down in the 30 25 million range, actually it's \$32 million was	1 MR. LUDLOW: 2 the average. Since 1997, excluding the Aliant 3 pole purchase, capital expenditures have 4 averaged \$47.5 million. Now this is more than 5 the '93 to '97 period, however less than the 6 average of the five-year period prior to the 7 cod moratorium, which was \$51 million. 8 Q. Mr. Ludlow, would you comment on the changes 9 in capital expenditures from 1993 to 2003? 10 A. Well, the changes in the expenditures from '93 11 to present were influenced by a number of 12 factors. As I mentioned, the purchase of the 13 Aliant poles, for approximately \$41 million 14 over a five-year period, has had an upward 15 effect on capital expenditures. This purchase 16 added approximately \$21 million in 2001, \$8. 17 million in 2002 and \$4 million in 2003. This 18 acquisition of the Aliant poles is justified 19 on the basis of economies of scale and has had 20 the effect of reducing the amount of pole 21 costs that had to be recovered in rates. 22 (10:02 a.m.) 23 In 1998, the Rose Blanche hydro plant was 24 constructed at a capital cost of \$13. 5 25 million. Then we have asset replacement has

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1 accounted for an increasing portion of capital 2 expenditures since 1999, when Newfoundland 3 Power began a focused effort to improve the 4 reliability of its poorest performing feeders, 5 and by feeders, I'm talking about the lower 6 voltage, somewhere between the house voltage 7 to transmission. So that would be in the 2400 8 to 14,000 volt range. During the period of 9 '93 to '98, between 30 and 46 percent of 10 capital expenditure was for capital, for plant 11 replacement. 12 Since 1999, greater than 50 percent of 13 capital expenditure has been focused on 14 replacement, and Newfoundland Power has an 15 obligation to serve new customers, that's 16 another block. The customer demand is a 17 direct function of economic conditions. 18 Capital expenditures associated with customer 19 demand declined from '93 to '98, and since 20 1998, have improved due to improved economy, 21 and expenditures in this category have varied 22 from a low of \$5.3 million in 1995 to a high 23 of \$12.2 million in 2003. This category would 24 include just the acts of transformers, street 25 lights and tying wires and extensions into the	1 housing. 2 The Information Systems capital 3 expenditures, as a percentage of total, have 4 gradually increased from 1993 to 2003. These 5 expenditures are directed towards improving 6 customer service and indeed, the overall 7 efficiency of our company. 8 General expenses capital have declined 9 from 1993 to 2003 and this decline flows from 10 Order P.U. 3 ('95/96) that resulted in a 11 decline in GEC from \$10 million in '93 to \$2.8 12 million in 2003. Finally, inflation is a 13 factor that has been a key influence on the 14 changes in capital expenditures over the past 15 ten years. Utility assets are long-life 16 assets so replacement costs will tend to be 17 greater than the original costs, and over the 18 past ten years, inflation alone has increased 19 in excess of 20 percent. 20 Q. Mr. Ludlow, would you please describe the 21 Company's plan for capital expenditures over 22 the next five years? 23 A. The Company estimates that approximately \$260 24 million will be invested in plant and 25 equipment during the period of 2004 to 2008.
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1 Expenditures are expected to average \$53 2 million per year and range from 49 million to 3 56 million. The Company plans to continue its 4 effort to refurbish under performing 5 distribution feeders with respect to the 6 reliability and the safety of those feeders. 7 We will also continue to inspect the balance 8 of our feeders on a five-year cycle and 9 correct resulting deficiencies identified. 10 In the substation category, the Company 11 plans to continue its effort to replace aged 12 and obsolete reclosers, many of which are at 13 the end of their estimated life right now, as 14 well as relays, and these will be replaced 15 with new multi-function digital units that are 16 remotely controlled from our system control 17 centre. This will modernize our protection 18 and control systems and result in improved 19 productivity and reliability. This plan will 20 also see an increased emphasis on the 21 refurbishment of transmission lines. Many of 22 these lines are older and deteriorated and by 23 that, a lot of that is a direct relationship 24 to age and the winds and weathers of our 25 province. Transmission line expenditures are	1 MR. LUDLOW: 2 expected to grow from 2.3 million in 2004 to 3 an average of \$6.2 million from 2005 to 2008. 4 MR. MYLES: 5 Q. Mr. Ludlow, there was much discussion on the 6 issue of radial transmission lines during the 7 2003 Capital Budget application. Can you 8 advise the Board whether the Capital Plan 9 addresses this issue? 10 A. Again, what I've taken here, Mr. Chairman, is 11 a map of the island, similar to what I used 12 before, and included what we classify as 13 radial transmission systems have been 14 identified in the circled blocks. There's 15 seven of them identified and namely, we have 16 the southwest coast to Port aux Basques. This 17 line is being worked on, I do believe, next 18 June. Hydro and ourselves are working 19 together now on the planning for that process. 20 We move on up to the 138 line feeding the Baie 21 Verte Peninsula. Then we have the 22 Twillingate, which is a single feed out of 23 Gander Bay--Gander Bay, I'm sorry, out of 24 Boyd's Cove area. We have the Gambo to New 25 West Valley area, Bonavista North. We also

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1 have the Old Perlican, Bay de Verde, Victoria 2 area. We have the Placentia-Argentia back to 3 Whitbourne, 55 L, and finally, we have 94-95 4 L, which simply transmission line numbers, 5 servicing the area from Blaketown through to 6 St. Catherine's, Riverhead and Trepassey. 7 Now, I've spoken to this Board on several 8 occasions on these, and simply put, a radial 9 transmission line is a single source of feed 10 for high voltage. You get a generator on one 11 end and you have customers on the other and a 12 long span in between is what it boils down to, 13 sometimes as much as 100 kilometres. We will 14 continue to address these issues of radial 15 lines and that's prevalent throughout this 16 five-year plan. We are concerned about the 17 future performance of these systems, given 18 that these radial transmission lines continue 19 to age and deteriorate and many are exposed to 20 some of the most severe weather conditions. 21 These aren't all the radial systems, by the 22 way. I should make that clear as well. 23 There's some not identified, 5L to Broad Cove 24 is not there. Pulpit Rock out of Virginia 25 Waters, which is Torbay area, is not there.	1 So there's some that we have where we're 2 located as short on our reaction time and 3 accessibility would make those what I would 4 call on a much less priority scale than the 5 ones we're dealing with here. 6 Now the Capital Plan, as presented before 7 this Board, includes projects that will 8 address two of these radial systems, and that 9 being Trepassey, with 94-95 L as I've 10 highlighted, and also the Old Perlican area. 11 In 2004, we plan to purchase a second portable 12 diesel generator and position it in Trepassey. 13 This will not provide complete backup for the 14 Trepassey radial system, but it will provide a 15 greater measure of security for the system in 16 this area. 17 And what I'm getting to there, 18 Commissioners, is to deal with issues of fire 19 fighting. It can deal with water supplies and 20 those types of basic needs. And we can cover a 21 fair amount of the load with a two and a half 22 megawatt generator in Trepassey. However, 23 that's its stationary point. When it is 24 needed for emergencies elsewhere, it would be 25 also available on the east coast. And also,
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1 we would use it during construction. And I've 2 spoken to this Board on those types of topics 3 before. 4 In 2005 we are proposing a project to 5 secure the radial transmission system in the 6 Old Perlican area. Now, this system contains 7 our oldest radial transmission line at 47 8 years. The Old Perlican project is roughly 9 estimated at 5.1 million dollars. Now, at 10 this point in time the detail is not 11 completed, however, an engineering study will 12 be completed and prepared and presented before 13 this Board at next year's hearing. The 14 Company intends to focus engineering efforts 15 in the future to monitor the reliability 16 performance of these radial systems, and we 17 would plan accordingly. 18 Q. Mr. Ludlow, again, in the capital plan, if I 19 could refer you to the next page, which would 20 be page 2 of 11, Appendix C of the plan, I 21 note that the capital plan contains several 22 large expenditures in energy supply category. 23 Could you please comment on these? 24 A. It's interesting, many of our hydro facilities 25 were built pre 1960. And in fact, I don't	1 MR. LUDLOW: 2 know if the average, but by far the majority 3 is greater than 50 years old at this point-in- 4 time. Hydro plant upgrades, particularly 5 penstocks and surge tanks, both of which are 6 presented in this picture. By the way, the 7 surge tank here is in effect a pressure relief 8 valve. In the event that you get a sudden 9 rush of water or the valve closes on the end, 10 it's a place for the water to go. And 11 secondly, this, I'm going to call it a pipe, 12 is, the wooden penstock, this one is in 13 particular in Rattling Brook. These items are 14 very costly in replacement and costs many 15 millions of dollars. 16 Now, in our plan we have timed these 17 projects keeping in the mind the Board's 18 desire to levelize capital costs over the 19 planning horizon. However, should 20 circumstances change such that the safety or 21 deterioration becomes such a concern, then 22 adjustments may be required and we would have 23 to revisit the plan with this Board. 24 The large energy supply projects planned 25 include a four million dollar expenditure at

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1 New Chelsea in the 2004 Application before us 2 here today which we'll describe later. 3 Actually, Mr. Delaney will take you through a 4 lot of that. And there is also a significant 5 expenditure in 2006, you can see the peak in 6 the graph, and that is, in fact, at the 7 Rattling Brook, Norris Arm area. That's a 8 plant we have that the penstock there as well 9 as that surge tank is in need of work. 10 Q. Mr. Ludlow, what do you think are the major 11 risks in the five year capital plan? 12 A. There are several risks associated with this 13 plan. One of the first ones would be the area 14 of customer and energy growth. Newfoundland 15 Power has an obligation to serve the customers 16 in our service territory. Should economic 17 factors change such that customer or energy 18 growth varies from our forecast, then so will 19 the capital expenditures have to vary 20 accordingly. We continue to be concerned 21 about the reliability of radial transmission 22 systems. Customers served by radial 23 transmission systems continue to experience 24 more and longer power interruptions than those 25 served by loop systems. And that's the loop	1 system basically is a system whereby you have 2 multiple sources of supply. Usually they 3 would be in highly populated areas, St. John's 4 or Corner Brook and those types of areas. The 5 2004 capital plan combined with projects 6 currently ongoing in 2003 to relocate a gas 7 turbine to New West Valley and the purchase of 8 a 2.5 megawatt portable diesel, which is 9 already under way, will address some of those 10 radial system, but not all of them. So we're 11 working on some of them as we go forward. We 12 will continue with our engineering efforts in 13 this area to determine viable solutions. This 14 may put upward pressure on the plan. 15 Another example is that of the customer 16 service system, or you will sometimes hear it 17 referred to as the CSS. It's eleven years 18 old. Replacement of that system could be as 19 high as 15 million dollars. Although we don't 20 forecast a need to replace that system during 21 the five year period presented before this 22 Board in the plan, changing technology and/or 23 a change in vendor support may cause a 24 revisiting of this area. 25 Q. Mr. Ludlow, do you have any do you have any
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1 concluding remarks? 2 (10:17 a.m.) 3 A. Commissioners, as I've previously stated, the 4 electricity business is premised on several 5 fundamentals, reliability, safety of both 6 employees and the general public, customer 7 service, productivity and the environment. 8 This industry is very capital intensive and it 9 uses long life assets. A refurbishment of the 10 electrical system to improve reliability, 11 excuse me, and performance is a key central 12 aspect of Newfoundland Power's 2004 Capital 13 Budget and remains so throughout the five-year 14 plan as presented. This plan is designed to 15 provide the necessary budget stability, all 16 while ensuring the strength and integrity of 17 our electrical system. Our ability to provide 18 the quality of service that our customers 19 expect and deserve at the lowest reasonable 20 cost will require continuous capital 21 investment. By investing capital in the right 22 places and at the right time we will optimize 23 the asset lives, we're better able to respond 24 to the demands of our new customers and we're 25 able to improve our productivity and the	1 MR. LUDLOW: 2 operational efficiency of our corporation. 3 That is the overall goal of the capital plan. 4 Q. Thank you, Mr. Ludlow. Mr. Delaney, I would 5 like to ask you some questions with respect to 6 the 2003 Capital Expenditure Status Report 7 found in Volume 1 and refer you to page 1 of 8 12. That would be the one with the first 9 revisions. Would you please comment on the 10 variances with respect to the 2003 Capital 11 Budget? 12 MR. DELANEY: 13 A. Good morning, Mr. Chairman and Commissioners. 14 The 2003 Capital Expenditure Status Report can 15 be found in Volume 1 of the pre-filed 16 Application and is summarized here on the 17 screen. In the first column we have the asset 18 category; the second column is the budget as 19 approved by the Public Utilities Board; the 20 third column shows the forecast as of May 21 31st; and the fourth column shows the variance 22 as of May 31st. As of May 31st we were a 23 total of 1.3 million or approximately 2.3 24 percent above budget. Variances from budget 25 are unavoidable due to many circumstances such

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1 as changes in work due to third party 2 requirements in field conditions, due to 3 changes in priorities, due to ongoing reviews 4 and reassessments of new events and price 5 changes or delays in the delivery of material 6 or in equipment. Now, detailed explanations 7 of individual variances were pre-filed in 8 Appendix A of the 2003 Capital Expenditure 9 Status Report. 10 Q. Mr. Delaney, earlier in the morning we filed 11 an exhibit PJD No. 1. And this shows the 12 Company's forecast 2003 Capital Budget 13 variances as of July 31st. Will you please 14 comment on the changes in the variances 15 between the May 31st forecast and the July 16 31st forecast? 17 A. Yes. This slide shows the most recent Company 18 forecast as of July 31st. Again, the first 19 column shows the asset category; the second 20 column shows the approved budget; and the 21 third column shows the forecast as of May 31st 22 that was filed with the Application; the 23 fourth column shows the most recent forecast 24 as of July 31st; and the fifth column shows 25 the variance between the July 31st forecast	1 and the approved budget. The overall variance 2 has increased by approximately \$80,000 and now 3 stands at approximately 1.37 million dollars 4 or 2.4 percent above budget. 5 I'll now comment on the significant 6 changes from the May 31st forecast as filed 7 and our most current information as of July 8 31st. 9 The energy supply category has decreased 10 187,000 since May, and this is due primarily 11 to the reduced cost associated with the 12 penstock replacement at Lockston on the 13 Bonavista Peninsula. We now have a forecast 14 variance of \$166,000 in the energy supply 15 category. 16 The substation category has decreased by 17 \$209,000 from May to July. This is primarily 18 due to the reduced cost for the Virginia Waters 19 transformer in St. John's, that's a new 20 installation, a reduction in the substation 21 rebuild project at Blaketown substation and a 22 reduction in a project we are undertaking to 23 improve the protection and monitoring of our 24 substations. We now have a variance of 25 \$547,000 below budget in the substations
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1 category. 2 The distribution category has increased 3 \$152,000 from May to July. And this is due to 4 an increase in the extensions project and the 5 Water Street underground switch replacement 6 project. We now have variance of 7 approximately 1.2 million dollars in this 8 category. And I'll note that this variance is 9 primarily driven by increased customer growth 10 which has increased the extensions and street 11 lighting projects, and there has been an 12 increase in the Glovertown O2 feeder 13 reliability project to accommodate a route 14 that has been approved by Parks Canada through 15 Terra Nova Park. 16 The transportation category has increased 17 by \$300,000 from May to July, and this is due 18 to the replacement of a heavy duty fleet that 19 was involved in an accident earlier this year. 20 The total variance for this category now 21 stands at \$487,000. 22 In the remaining categories there have 23 only been minor changes since the May 31st 24 forecast. And this concludes my discussion on 25 the 2003 capital expenditures.	1 MR. MYLES: 2 Q. Mr. Delaney, would you please provide an 3 overview of each of the categories of the 2004 4 Capital Budget for which you are responsible 5 here today? 6 A. The 2004 Capital Budget is summarized in 7 Schedule A of the Application where the budget 8 is broken down by asset category. The total 9 budget is \$53,909,000. And I would describe 10 to the Board the projects in the categories 11 listed on the screen with the exception of the 12 information systems category which will be 13 dealt with by a--Michael Mulcahy and Peter 14 Collins. 15 Q. All right. Looking first at energy supply in 16 Schedule B, page 1. What can you tell us 17 about this category? 18 A. The energy supply category lists those capital 19 projects pertaining to the Company's 20 hydroelectric and thermal plants. 21 Newfoundland Power operates 23 hydroelectric 22 plants. Our hydro plants provide a low cost 23 and reliable source of electrical energy. Our 24 thermal plants, which are gas turbines and 25 diesels, are located strategically around the

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1 island to provide a valuable source of backup 2 power. As well, we have portable thermal 3 generation available to respond to emergencies 4 and for construction projects. In 2004 we 5 propose to spend \$6,945,000 in the energy 6 supply category, and this expenditure is 7 broken down into four distinct projects. 8 First, the hydro plants facility 9 rehabilitation project is estimated at 10 \$1,122,000. And this project is necessary for 11 the replacement or rehabilitation of 12 deteriorated, defective and obsolete hydro 13 plant components. Second, the New Chelsea 14 hydro plant refurbishment project is estimated 15 at \$3,973,000. And this project involves the 16 complete refurbishment of the New Chelsea 17 hydro plant. Third, the purchased portable 18 diesel generation project is estimated at 19 \$1,700,000. This project consists of the 20 purchase of a second 2.5 megawatt portable 21 diesel generator identical to a unit being 22 purchased this year. And finally, major 23 electrical equipment repairs estimated at 24 \$150,000 is necessary to provide for the cost 25 of major equipment replacement due to	1 deterioration and catastrophic failures. 2 Q. Mr. Delaney, could I refer you to Schedule B, 3 page 10? This shows \$1,122,000 for hydro 4 plant facility rehabilitation. Could you 5 advise the Board what is proposed here? 6 A. There are a number of hydro plants that 7 require work in 2004. And I will focus on 8 work proposed in two plants to explain to the 9 Board the nature of this project. 10 Now, this is our Morris Plant on the 11 southern shore. Our hydro plant operations 12 employees are experiencing problems with the 13 Morris Plant turbine. The wicket gates that 14 perform the critical function of controlling 15 the amount of water that flows through the 16 turbine are not operating properly and we are 17 not getting the amount of production we should 18 from the water resource available, therefore 19 the plant is operating inefficiently. 20 Now, if we can look at the screen, I can 21 describe this in a little bit more detail. 22 This is the turbine at Morris Plant. The 23 water comes in this turbine, comes around this 24 area, spins the turbine around which creates 25 the rotational movement of the shaft which
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1 goes into the generator and the water exits 2 through this pipe here. Now, this is inside 3 the turbine. These stainless steel items are 4 called wicket gates. They're not evil, 5 they're wicket. They control the amount of 6 water that goes through the turbine and they 7 are supposed to be lined up in a more linear 8 fashion, I would say. But what's happening is 9 the wicket gates are getting stuck. This one 10 here is clearly stuck, and they're not lining 11 up properly so the water is not flowing as we 12 desire and it's inefficient. It's getting 13 stuck because these things around here, which 14 are called stationary seals, are corroded and 15 the stainless steel is getting just stuck 16 against the corrosion of the station seal. 17 So we have a project in next year's budget to 18 improve the efficiency of this plant, to 19 replace these stationary seals. 20 In Volume 2, Energy Supply, Appendix 1, 21 attachment B of the Application we have filed 22 a report entitled "Morris Plant, Turbine and 23 Stationary Seal Inspection", that explains 24 this item in greater detail. 25 Another item in this project is to rewind	1 MR. DELANEY: 2 generator No. 1 at Rattling Brook plant. Now, 3 Rattling Brook is our largest plant. It 4 consists of two generators. And in 2002 we 5 experienced an unexpected failure in generator 6 No. 2 and the generator coils had to be 7 rewound. That's a labour intensive process 8 that took over eight months. 9 And just refer to the picture here. This 10 is the generator at Rattling Brook and this 11 generator is actually in a vertical alignment 12 as opposed to the Morris the last time which 13 was in a horizontal alignment. So this is the 14 generator, this is the coils. This is inside 15 the generator and these are the coils. And 16 like I said, there's two generators at 17 Rattling Brook. Last year generator No. 2 18 failed, and it failed, these coils actually 19 short circuited and, you know, they were 20 rendered useless due to the short circuit. So 21 we had to rewind all this stuff, took about 22 eight months on site to rewind this generator 23 under the conditions we had to work. 24 Now, both generator No. 1 and generator 25 No. 2 are identical units. Both are 45 years

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1 old, and it's seen the same duty, the same 2 usage over the years, over the 45 years. The 3 estimated life if a generator winding is 30 to 4 40 years, in the industry it's pretty well 5 accepted. Given that generator No. 2 windings 6 failed, we are obviously concerned about 7 generator No. 1 and we plan to rewind 8 generator No. 1 in 2004. And this project is 9 discussed in further detail in Volume 2, 10 Energy Supply, Appendix 1, page 3 of 5. 11 Q. Mr. Delaney, could I now refer you to Schedule 12 B, page 12? This describes a project to 13 refurbish the New Chelsea hydro plant costing 14 approximately four million dollars. Can you 15 please describe this project for the Board? 16 A. The New Chelsea plant is 47 years old. It's 17 located in the Community of New Chelsea in the 18 Trinity Bay South area. The expected service 19 life of equipment in the plant is between 25 20 and 40 years. To ensure the continued safe, 21 reliable, low cost and environmentally sound 22 operation of this plant, we need to refurbish 23 the plant. Now, I'll start first from a 24 public and employee safety perspective. The 25 penstock requires replacement. And here is	1 the penstock, and here is an up close picture 2 of the penstock here. There are 20,000 wooden 3 wedges in the penstock, over 20,000 to plug 4 holes where the penstock has leaked in the 5 past. And there are over 200 metal plates 6 like this here where more significant blowouts 7 have occurred over the years. As well, we 8 performed ultrasonic testing on a steel 9 portion of that penstock. The penstock is a 10 combination of wood and steel, and we found 11 substantive corrosion on the inside, which 12 leads us to conclude that the penstock has 13 reached the end of its useful service life. 14 (10:32 a.m.) 15 As well, the electrical protection, 16 control systems are all of an 17 electromechanical nature, they're original to 18 the plant, 47 years old and we plan to 19 replace those in conjunction with this 20 project, to do a complete refurbishment of 21 this plant. Of particular note on the 22 electrical end, the existing generator 23 protection does not meet current minimum 24 standards. The plant is not protected for 25 stuff such as over voltage, over frequency and
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1 there are other electrical contingencies. 2 So, we plan a complete refurbishment of 3 the New Chelsea plant while we have that 4 penstock out of service, the electrical 5 controls out of service, we hope to, you know, 6 decrease our overall capital cost and be as 7 productive as possible by modernizing the 8 entire plant. 9 And this project is described in detail 10 in an engineering report that has been filed 11 with the Board in Volume 2, Energy Supply, 12 Appendix 2, Attachment A. 13 Q. Mr. Delaney, what does this slide show? 14 A. This slide shows before and after pictures. 15 Obviously this is before, and after, of the 16 Seal Cove penstock. This is the new penstock 17 and this is the old one. In 2002 we did this 18 project in New Chelsea and on occasion the 19 new--sorry. We did this job in Seal Cove in 20 2002. And on occasion the New Chelsea 21 penstock looks like the old Seal Cove 22 penstock. So we intend to repeat the success 23 that we had in Seal Cove in New Chelsea in 24 2004. 25 Q. Mr. Delaney, could I now refer you to Schedule	1 MR. MYLES: 2 B, page 14? This states that the Company 3 plans to purchase a second 2.5 megawatt 4 portable diesel generating unit. Can you 5 discuss the reasons behind this project? 6 A. A backup generation is invaluable in times 7 where there is large scale damage to the power 8 system and customers could be without power 9 for several days. This is especially true for 10 those rural customers served by radial 11 transmission systems that have only one source 12 of supply. A report we filed with the Board in 13 the 2003 capital budget application entitled 14 "Portable Diesel Generation, Reliability 15 Analysis, Sizing and Unit Location Review" 16 recommended the purchase of a five megawatts 17 of portable diesel generating capacity to 18 serve the full load of the majority of our 19 rural distribution lines. Now, due to 20 physical size limitations a 2.5 megawatt 21 diesel generator is the biggest that we can 22 mount on a trailer and make it portable. So 23 in 2003, this year, we've obtained approval 24 from the Board for the purchase of the first 25 portable diesel generator. And that unit will

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1 be located in Port aux Basques on the west 2 coast, unless it's needed elsewhere for 3 emergencies or construction projects. This 4 project before the Board now for 2004 is for 5 the purchase of the second 2.5 megawatt unit 6 to bring our portable diesel generating 7 capacity up to the recommended five megawatts 8 for emergency backup for our customers on 9 radial transmission systems. When it's not 10 required for emergencies or construction 11 projects, we propose to locate the second unit 12 on the east coast of the province at Trepassey 13 substation. 14 Q. Mr. Delaney, could I refer you back to page 2 15 of Schedule B? This shows the substation 16 category. Can you give the Board the 17 highlights of this category? 18 A. Newfoundland Power operates 137 substations. 19 The fundamental purpose of a substation is to 20 transform voltages from transmission level to 21 distribution level and to protect and control 22 the transmission and distribution of power. 23 In 2004 we propose to spend \$5,199,000 in the 24 substations category. This expenditure is 25 broken down into seven projects, as shown on	1 the screen. 2 The rebuild substations project of 3 \$1,000,023 is necessary for the replacement of 4 deteriorated and substandard substation 5 infrastructure. 6 The replacement and standby substation 7 equipment project estimated at \$1,314,000 is 8 required to replace obsolete and unreliable 9 electrical equipment and to maintain an 10 appropriate level of spares to use during 11 emergencies. 12 The transformer cooling refurbishment 13 project at \$398,000 is required to replace 14 corroded radiators on our substation 15 transformers. This will prevent oil spills 16 and the associated environmental clean up 17 costs. 18 The protection and monitoring improvement 19 project at \$80,000 is needed to make small 20 upgrades in our protection and control systems 21 in substations. 22 The distribution theatre remote control 23 project at \$1,000,000 is a project initiated 24 in 2002 to replace a number of aging, limited 25 function electrical mechanical relays, feeder
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1 relays and oil filled reclosers with modern 2 units that can be remote controlled island 3 wide from our system control centre in St. 4 John's. 5 The project for feeder additions due to 6 low growth and reliability at \$200,000 is 7 necessary for upgrades at two substations to 8 accommodate customer growth and reliability 9 issues. 10 The increased Corner Brook transformer 11 capacity project at \$1,184,000 is necessary to 12 prevent forecasted substation transformer 13 overloads. 14 Q. Mr. Delaney, could you now refer to page 18 of 15 Schedule B. Could you address the substation 16 rebuild project at a cost of \$1,023,000 and 17 advise the Board what is proposed here? 18 A. There are a number of substations that will 19 require work in 2004. And I'll focus on the 20 work proposed in two substations to explain to 21 the Board the nature of this project. 22 This is the Grand Bay substation in Port 23 aux Basques. We are experiencing problems in 24 this substation due to congestion. There is 25 simply not enough room for the equipment	1 MR. DELANEY: 2 that's stationed there. Our portable gas 3 turbine is located at this substation and our 4 2.5 megawatt portable diesel generator will be 5 stationed there when it arrives later this 6 year. The substation must be modified to 7 ensure that there are no delays when this 8 portable equipment is required during 9 emergencies to restore service to customers, 10 as well, a better layout is required to avoid 11 employee safety concerns associated with 12 congestion at this substation. And this item 13 is described in Volume 2, Substations, 14 Appendix 1, page 1 of 6. 15 This is our Indian Cove substation on New 16 World Island. The substation is 35 years old, 17 it's a small substation, and it's at the end 18 of its useful service life, must be upgraded. 19 The substation transformer has severe rusting. 20 There's a risk of an oil spill, which is an 21 environmental concern. And our reliability 22 concern is in that the wooden cross arms have 23 burn marks and some are severely bent. As 24 well, the switches, and I'll just point some 25 of these things out here, the transformer here

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1 has rusting. Of course, we're concerned of an 2 oil spill. And the cross arms, which are 3 these timbers going across here, there's burn 4 marks. There's one here, it's hard to see on 5 the picture, but it shows that there's 6 evidence that there's been trouble on this 7 line and of course, the strength of this cross 8 arm is severely reduced by that burn. And 9 there's some severe bends in the cross arms. 10 As well, the switches are out of alignment due 11 to the torsional type of movement that's going 12 on with the poles. And that makes some--it's 13 a safety hazard for our employees, the switch 14 that's out of alignment. And this item is 15 described in further detail in Volume 2, 16 Substations, Appendix 1, page 2 of 6. 17 Q. Mr. Delaney, could I now refer you to Schedule 18 B, page 20? This is a project for \$1,314,000 19 for replacement and standby substation 20 equipment. Could you please describe this 21 project to the Board? 22 A. The replacement and standby substation 23 equipment project involves the purchase and 24 installation of substation equipment to 25 address issues of obsolescence and	1 deterioration. As well, the project ensures 2 we maintain an adequate level of spares in our 3 inventory to address emergencies and to ensure 4 that maintenance activities are carried out in 5 an efficient manner. A typical item in this 6 project is breaker replacement. Now, this is 7 a 66,000 volt circuit breaker located at 8 Pepperal substation in Pleasantville, St. 9 John's. The breaker is 51 years old. It is a 10 one of a kind in our system right now. The 11 parts are obsolete. We can no longer purchase 12 spare parts for this breaker. In 2004 we plan 13 to replace it with a new SF6. So this is the 14 old breaker here, it's 51 years old, like I 15 say, and we just don't have spare parts for it 16 any more and can't get them. It also has to 17 operate quickly to get faults off the system 18 and it's just not sufficient. This is the 19 newer breaker, which is an SF6 breaker that we 20 will replace the older breaker with. This 21 project is described in further detail in 22 Volume 2, Substations, Appendix 2, page 1. 23 Q. Mr. Delaney, could you now refer to page 26 of 24 Schedule B? This addresses the distribution 25 system feeder remote control project. Could
Page 55	Page 56
1 you describe the one million dollar 2 expenditure to the Board? 3 A. In 2004 we are continuing with a program 4 started in 2002 to install distribution 5 theatre remote control. Each of our 300 6 distribution theatres has a device to control 7 and protect the feeder, either a relay or a 8 recloser. Should a power line fail or should, 9 like, energize wires fall to the ground, this 10 is the equipment that we depend on to operate 11 automatically to ensure that the power is 12 disconnected. The screen shows old and new 13 relays and reclosers. In 2004 we plan to 14 install 25 new relays and six new reclosers. 15 By the end of 2004 we expect to have a total 16 of 65 new relays and 36 new reclosers 17 installed in the system. And this project is 18 timely due to the age of the equipment being 19 replaced and there are several benefits. 20 And I'll go through some of the benefits 21 with this new technology. The first is we're 22 improving reliability. The new technology 23 enables the system control centre to monitor 24 and control distribution theatres. The system 25 control centre operators can quickly pinpoint	1 MR. DELANEY: 2 trouble spots and direct the field crews 3 accordingly. And there are instances when the 4 operators can restore power without 5 dispatching anyone in the field, and this 6 reduces outage durations for customers. 7 Second, we're minimizing the risk due to oil 8 spills. The old reclosers that we have, they 9 utilize about 200 litres of oil, and oil is 10 needed to extinguish the arc that occurs when 11 the break happens in the electricity, opens 12 the electricity. The newer reclosers have no 13 oil, that activity, that breaking of the arc 14 occurs in a vacuum chamber. Third, we are 15 reducing operating costs by bringing in this 16 new technology. And a very good example of 17 that is tree trimming around power lines. 18 Tree trimming is something we do every year. 19 We continually have to monitor and trim the 20 vegetation around power lines; it's an 21 essential part of the operations. So, on 22 feeders without this technology, we need to 23 send somebody to the substation at the 24 beginning of each day to adjust settings at 25 the substations, then the contractor can go to

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1 work, do his tree trimming. And then at the 2 end of the day, we have to go back to the 3 substation and adjust settings back again. On 4 feeders with this new technology, the tree 5 trimming contractor would call into our system 6 control centre and all those adjustments are 7 all now done remotely. So, this is saving us 8 a lot of time, going to substations and 9 cutting down on our costs. 10 Q. Mr. Delaney, could I refer you to page 30 of 11 Schedule B? This is a project to increase the 12 Corner Brook transformer capacity, could you 13 describe this project to the Board? 14 A. In Corner Brook, we have seen gradual customer 15 growth. There are the new developments at the 16 Sir Wilfred Grenfell College with the addition 17 of several building, the Canada Games Centre 18 is in this area as well. There is a big box 19 retail development in Corner Brook at Murphy's 20 Square which includes Wal-mart, Dominion, 21 Canadian Tire, Staples and other strip malls. 22 As well, there has been residential 23 subdivision developments such as Sunnyslope. 24 Now, customers in Corner Brook are served by 25 three substations, Walbournes, Humber and	1 Bayview. And each of these three substations 2 is interconnected. Installing a new 3 transformer is a big ticket item. It's a lot 4 of money to put a new transformer in, as you 5 see, it's over a million dollars. So, for the 6 past number of years, we've been successful in 7 deferring the need to put this new transformer 8 in Corner Brook, in a substation. And we've 9 done this by transferring the loads between 10 substations. For example, as the Walbourne's 11 transformer would approach overload due to 12 developments up around, say, the Sunnyside 13 subdivision, Sunnyslope subdivision, we'd 14 install switches on the distribution feeders 15 and redirect parts of the load to Humber, 16 Bayview, that's a fairly small cost thing to 17 do, to redirect the loads. 18 Now, we've now reached a point where that 19 approach is no longer feasible. We're 20 projecting this year that the peak load in 21 Corner Brook will be slightly greater than the 22 total combined capacity of all three 23 substation transformers. So, now we have to 24 add the additional capacity. We studied this 25 situation, we looked at alternatives and
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1 decided that the least cost alternative is to 2 install a new 25 MVA transformer at the 3 Walbourne substation and as well, we have to 4 relocate the smaller of the two units 5 currently in service at Walbournes over the 6 Bayview substation. 7 (10:47 a.m.) 8 And I'll refer the Board to Volume 2, 9 substation, Appendix 4, Attachment A where 10 this a report entitled power transformer 11 study, city of Corner Brook which describes 12 this project, the alternatives considered, the 13 financial analysis, et cetera, describes it in 14 detail. 15 Q. Mr. Delaney, could you refer back to page 3 of 16 Schedule B? This shows the transmission 17 category, could you describe this project to 18 the Board? 19 A. Newfoundland Power operates 110 transmission 20 lines that have an overall length of greater 21 than 2000 kilometres. And 30 percent of our 22 transmission lines are more than 40 years old. 23 In 2004, Newfoundland Power proposes to spend 24 \$2,315,000.00 to upgrade its transmission line 25 system. And this work is identified during	1 MR. DELANEY: 2 the course of annual inspections carried out 3 on transmission lines. Within this overall 4 project there are several items and I'll 5 discuss two in detail to give the Board 6 information on this project. The first is a 7 \$380,000.00 expenditure to rebuild a 5.1 8 kilometre section of transmission line 403L. 9 And this is a picture of transmission line 10 403L that runs from St. Georges to Robinsons 11 to our Lookout Brook hydro plant on the west 12 coast in the Bay St. George area. This line 13 was built in 1958 and inspections have 14 determined that there is significant 15 deterioration of the poles, cross arms and 16 other hardware. And extensive upgrading is 17 needed to ensure the continuity of service for 18 customers in this area. And this transmission 19 line, as I said is 45 years old, has reached 20 the end of its useful service life. 21 The second item is \$197,000. 00 22 expenditure to increase the conductor or wire 23 size on transmission line 16L. Now, this is 24 16L. I just want to point out that the 25 transmission line is the top circuit, three

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1 wires, one of the wires is kind of hidden, 2 they're small wires. And below, this is 3 actually a distribution feeder. So, this is 4 what we call underbuild. In St. John's, there 5 is quite a bit of that. But this is a 16L, 6 it's a short line, runs along the Boulevard 7 from Pepperell substation in Pleasantville to 8 King's Bridge substation near Memorial 9 Stadium. Now, we've filed a report with this 10 application in Volume 2, Transmission Appendix 11 1, Attachment A, entitled "The St. John's 12 Transmission Capacity Review". And in that 13 study, we used engineering models to analyze 14 the St. John's transmission line system during 15 contingencies. Now, a contingency is when one 16 transmission line fails. Because the 17 transmission system is all interconnected, 18 when one transmission line fails, there's 19 effects on other transmission lines. If the 20 load that was normally flowing on a 21 transmission line fail, the load would go 22 different ways to get to the customers. So, 23 this was a fairly complicated study; it's 24 filed with the Board, analyze these 25 contingencies. And we've determined that our	1 contingencies that should another transmission 2 line fail, 16L will overload and the risk 3 there, 16L, the conductor is just not big 4 enough to handle the load. So, that's a 5 weakness, the small conductor size on 16L 6 transmission line. And the risk there is 7 overload conductor, the conductor can burn off 8 and it could result in an outage on the entire 9 east end of St. John's, from St. John's right 10 down to Pouch Cove. So, we have to increase 11 the conductor size on 16L. 12 Q. Mr. Delaney, could I now refer you to Schedule 13 B, page 4? This shows the distribution 14 category and can you describe these 15 expenditures to the Board? 16 A. Newfoundland Power is primarily a distribution 17 company. We operate over 8000 kilometres of 18 distribution lines to serve approximately 19 220,000 customers. Capital expenditures in 20 the distribution category amount to 21 \$27,636,000.00 or 51 percent of the entire 22 budget. Approximately one half of the 23 distribution category or one quarter of the 24 entire budget is associated with providing 25 service to new customers who wish to connect
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1 new homes and businesses to the power grids. 2 And the cost to connect the new customers is 3 included in the first five projects listed on 4 the screen. These are extensions, meters, 5 services, street lighting and transformers. 6 In the distribution category we have listed as 7 well, the Aliant pole purchase at 8 approximately \$4,000,000.00. This is an 9 expenditure previously approved by the Board 10 for the acquisition of Aliant joint use poles. 11 As well, we have a \$100,000.00 estimate for 12 industry construction and this is an amount 13 calculated in accordance with order number 14 P.U. 37 (1981). 15 Q. Mr. Delaney, could I now refer you to page 44 16 of Schedule B? Can you explain to the Board, 17 the nature of the expenditure of about 2.4 18 million dollars shown there for 19 reconstruction? 20 A. Reconstruction expenditure is driven by a 21 distribution feeder inspection program that 22 works in a five-year cycle such that 20 23 percent of distribution system is inspected 24 annually. We filed with the Board our 25 Distribution Inspection Standard in Volume 3,	1 MR. DELANEY: 2 Distribution Appendix 2, Attachment A. These 3 inspections are required to ensure the safety 4 and reliability of our system. During the 5 course of these inspections, we identify 6 numerous deficiencies and depending on the 7 severity, the deficiencies are prioritized in 8 four categories; Emergency, Priority One, 9 Priority Two and Priority Three. Emergency 10 and Priority One deficiencies are covered in 11 the reconstruction account in the current 12 year. Priority Two and Priority Three 13 deficiencies are identified for capital 14 expenditure in the following year under a 15 project called Rebuild Distribution Feeder 16 Upgrades. 17 Now, this is a deficiency found during 18 our inspections this year, it was in Caribou 19 Road in Corner Brook. The pole is leaning on 20 an angle such that we would classify it as a 21 Priority One deficiency and we're now working 22 on this project which may require the 23 replacement of several poles under the 24 reconstruction account. And it's a very--this 25 may, because when you replace a pole, it

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1 usually has an effect on the adjacent pole. I 2 actually visited this pole over the weekend in 3 Corner Brook and this building has been torn 4 down. So, it's going to make this job a lot 5 easier to do, to correct this deficiency. 6 Another aspect of the reconstruction 7 expenditure is to address minor storm damage 8 and items of imminent failure that come to our 9 attention that are outside the inspection 10 program. 11 Q. I'd like to refer you first to page four of 12 Schedule B and then from there to page 47 of 13 Schedule B. Can you describe the Distribution 14 Trunk Feeders Project? 15 A. Yes, this project entails a variety of work we 16 plan to do to upgrade the distribution system 17 in 2004. The majority of the expenditure, 18 approximately two thirds is for feeder 19 upgrades and this ties into the reconstruction 20 project described previously. Coming out of 21 our annual inspection process, we'll identify 22 numerous deficiencies on our distribution 23 system. The Emergencies and the Priority One 24 deficiencies are addressed under the 25 reconstruction account in the current year, as	1 I just noted. But those deficiencies deemed 2 to be Priority Two or Three are completed in 3 the following year under the Rebuild 4 Distribution Project, Feeder Upgrades. As 5 well, there are a number of safety, 6 reliability and environmental concerns 7 addressed in this project. These concerns are 8 described in a number of reports that we have 9 filed with the Board in Volume 3, Distribution 10 Appendix 2, Attachments B through G. The 11 picture shows three of these concerns we are 12 addressing with the rebuild distribution 13 project. The green box in the top picture is 14 a pad mount transformer. These transformers 15 are exposed to road salt, mechanical damage by 16 snowploughs and there's a degree of 17 undermining and back filling that happens by 18 property owners in the course of landscaping 19 their properties. These transformers are 20 located in residential neighbourhoods and 21 therefore, we have a concern for safety and 22 the prevention of oil spills. We expect to 23 replace about 300 of the 400 pad mount 24 transformers we have in service in St. John's 25 over the next five years as these units reach
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1 the end of their 30 year service life. 2 The middle picture is two broken cutouts, 3 failure of porcelain cutouts is a safety and 4 reliability problem. Cutouts are mechanical 5 switches for distribution lines. They are 6 used to disconnect and reconnect power to a 7 distribution transformer and branch lines. 8 Our line employees use hook sticks to manually 9 open and close these cutouts. So, failure of 10 the cutout is a safety concern for a line 11 personnel who must be in close proximity when 12 manually operating these devices. 13 The bottom picture is a deteriorated 14 automatic sleeve. Automatic sleeves are used 15 to connect two pieces of wire together. The 16 problem with automatic sleeves is one of 17 internal corrosion. In 2002, we have a sleeve 18 failure and performed an investigation. We 19 took 35 automatic sleeves out of service that 20 were in the field and found 13 to be severely 21 corroded. When an automatic sleeve fails, 22 there's a possibility that the energized wires 23 can fall to the ground which poses a serious 24 safety hazard for employees and the general 25 public. So, we've included automatic sleeve	1 MR. DELANEY: 2 replacement in our five-year distribution 3 inspection cycle. 4 Q. Mr. Delaney, can I refer you to page 52 of 5 Schedule B? Can you describe the distribution 6 reliability initiative? 7 A. In 2004, we plan to continue the distribution 8 reliability initiation and focus on three 9 areas of reliability concern in the 10 distribution system. These are the Lumsden, 11 Cape Freels area, Bonavista North served by 12 distribution feeder Wesleyville 02, the Bay 13 Roberts, Port de Grave area served by Bay 14 Roberts 04 feeder; and finally the Torbay, 15 Flatrock, Pouch Cover area which is served by 16 the Pulpit Rock 01 and Pulpit Rock 02 feeders. 17 I'll focus on the Wesleyville 02 item to 18 explain to the Board the nature of this 19 project. The Lumsden, Cape Freels, Bonavista 20 North is served by the Wesleyville 02 21 distribution feeder. Now, this item is 22 estimated at \$699,000.00 in 2004 with a 23 further \$400,000.00 in 2005 to complete the 24 feeder. We have filed with the Board a report 25 with this application found in Volume 3,

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1 Distribution Appendix 3, Attachment A, 2 entitled, "A Review of reliability, 3 Wesleyville 02 feeder". The feeder is 40 4 years old and as the line ages, it will not 5 withstand the severe weather conditions in 6 which it must operate. This is an area 7 frequented by sleet and strong winds. 8 Reliability performance has been well below 9 the company average. This year, in fact, the 10 reliability performance on Wesleyville 02 is 11 eight times worse than that company average. 12 2002 was another bad year, we experienced 13 eight outages on this feeder. Due to the 14 distribution feeder, we experienced eight 15 outages. This resulted in a letter of 16 complaint, meeting with local municipal 17 council. The lines should be rebuilt 18 2004/2005 to a heavier load design and to a 19 stronger construction standard to withstand 20 the environment in which it must operate. And 21 by budgeting and planning this way, we will 22 significantly improve the reliability in an 23 organized and productive fashion. Otherwise, 24 there's a risk that storms will continue to 25 cause damage, costly damage that must be	1 repaired under rushed emergency conditions to 2 get the power back on with no significant 3 improvement in the long run. 4 (11:02 a.m.) 5 Q. Mr. Delaney, at page 54 of Schedule B, there 6 is a project entitled, "Feeder Additions and 7 Upgrades to Accommodate Growth", estimated 8 cost of \$677,000.00, can you describe this 9 project to the Board? 10 A. The biggest item in this project is to 11 construct a new feeder, Chamberlins 03 from 12 the Chamberlins substation in Conception Bay 13 South. This will cost \$522,000.00 in the 14 distribution category and will require a 15 further expenditure of \$106,000.00 in the 16 substations category. I'll take the Board 17 through the slide to explain what we're doing. 18 Customers in Conception Bay South are served 19 by three interconnected substations. They are 20 Seal Cove, Kelligrews and Chamberlins. Now, 21 the immediate problem here is the substation 22 transformer is overloaded in Seal Cove and the 23 substation transformer in Kelligrews is 24 forecasted to overloaded this year, in 25 Kelligrews. So, in order to determine the
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1 best, least cost solution over the long-term 2 to serve the growth in this area, we undertook 3 a study of the entire area which has been 4 filed with this application and is in Volume 5 3, Distribution Appendix 4, Attachment A. The 6 least cost alternative to supply the growing 7 needs in Conception Bay South is to construct 8 this new feeder, Chamberlins 03 and we'll go 9 along the CBS bypass road down towards 10 Kelligrews. 11 Now, this alternative takes advantage of 12 the additional transformer capacity that we're 13 installing this year in Chamberlins. So, 14 what's going to happen is we're going to off 15 load Kelligrews onto this new feeder, 16 Chamberlins 03 feeder. So, that will 17 eliminate the overload in Kelligrews and 18 cascading, we'll off load Seal Cove onto 19 Kelligrews and that will do us well into the 20 future to handle the growing needs. 21 Q. Mr. Delaney, if I could refer you now to page 22 - 23 CHAIRPERSON: 24 Q. Mr. Myles, I think we were going to take a 25 break at 11:00, we're a little bit past, so	1 CHAIRMAN: 2 unless you're going to be a short further time 3 with Mr. Delaney? 4 MR. MYLES: 5 Q. I'm guessing 10 minutes, 15, 10 I'd say, I 6 only have another eight pages here. 7 CHAIRPERSON: 8 Q. All right, we'll adjourn at this particular 9 point in time and come back at 11:30. 10 MR. MYLES: 11 Q. Yes. 12 (RECESS - 11:04 A.M.) 13 (RESUME - 11:33 A.M.) 14 CHAIRPERSON: 15 Q. Mr. Myles, carry on, please. 16 MR. MYLES: 17 Q. Thank you, Mr. Chairman. Mr. Delaney, can I 18 now refer you to page 56 of Schedule B? This 19 refers to a project estimated at \$750,000 for 20 switch replacement and upgrade underground 21 distribution on Water Street in St. John's. 22 Can you describe this project to the Board? 23 MR. DELANEY: 24 A. This is a project which started in 2000 to 25 upgrade the underground system along Water

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1 Street in St. John's, and 2004 will be the 2 last year of this project. There are two 3 concerns that we are addressing in this 4 project. The first concern pertains to the 5 safety, deterioration, obsolescence of the 6 underground switches that are located in 7 manholes under Water Street. These switches 8 are no longer supported by the manufacturer 9 and here we have a picture of one being taken 10 up from underground and there's severe 11 corrosion on these switches. So this is since 12 2000, seven of the thirteen switches had been 13 replaced. Five are planned for this year and 14 in 2004, the one remaining switch will be 15 replaced. 16 A second concern in this area are the 17 transformer banks that are mounted on 18 platforms along several of the streets that 19 connect Water Street and Harbour Drive. These 20 transformer platforms are beyond their 21 estimated service life of 30 years, and as 22 well, there is safety concern when customers 23 need to perform maintenance on the exterior of 24 their buildings in close proximity to these 25 platforms. This slide shows Baird's Cove in	1 St. John's and if you go along Water Street 2 and Harbour Drive, you notice going through 3 these side streets, there's a lot of 4 platforms. Now this is during construction 5 here. The platform is being removed. You 6 notice this platform, there are two poles, 7 some crossarms, a platform and there'll be 8 three transformers. In Baird's Cove, we had 9 one on this side of the street and one on the 10 other side of the street. Like I say, this is 11 during construction. Obviously in close 12 proximity to these buildings, actually opening 13 up these windows, they're within arm's length 14 of the platforms, and this is the situation on 15 Baird's Cove now. The platforms have been 16 removed. I'm advised that this streetlight 17 pole is going to be removed as well. So we're 18 continuing on with this work, upgrading a 19 number of vaults in buildings to relocate 20 these transformers off the platforms into 21 vaults. In 2004, we plan to remove the 22 remaining platform mounted transformers. 23 Q. Mr. Delaney, can I refer you back to page five 24 of Schedule B? This shows the general 25 property category and can you describe this
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1 project for the Board? 2 A. The general property category is \$709,000 or 3 just over one percent of the total budget. 4 This category includes expenditures related to 5 upgrading buildings, real property. For 6 example, we are replacing the roof on our 7 Stephenville building. A portion of this roof 8 was damaged by high winds earlier in 2003. A 9 second component of the general property 10 category is the addition and replacement of 11 tools and equipment. In this job in the 12 picture here, we have our lineman performing 13 what we call hot line maintenance, and they'll 14 actually upgrading this structure while the 15 line is still energized. This line is still 16 carrying high voltage. So that avoids an 17 outage to our customers and we can perform the 18 capital maintenance. All this orange 19 equipment is what we call hot line equipment. 20 So it's obviously required for safety reasons. 21 So should that equipment not comply to the 22 high standards that we hold for that 23 equipment, it must be replaced. 24 Q. Could you now refer to page six of Schedule B, 25 and this shows the transportation category and	1 MR. MYLES: 2 can you describe to the Board what this 3 category includes? 4 A. The transportation category includes 5 \$3,487,000 or approximately six percent of the 6 total budget. We will not be increasing the 7 size of the fleet. However, we need to 8 replace twelve of our heavy line vehicles, 9 fifteen passenger vehicles and nine small all- 10 terrain vehicles, such as snowmobiles and 11 trailers. We continue to review the mix of 12 vehicles to ensure--to increase our overall 13 utilization and to reduce our costs. For a 14 passenger vehicle, a replacement guideline is 15 five years, 150,000 kilometres, and for a 16 heavy fleet vehicle, the replacement guideline 17 is ten years or 250,000 kilometres. Now this 18 guideline initiates a review of the vehicle 19 maintenance costs, its operating history and 20 the condition of the vehicle before a decision 21 is made to replace. 22 Q. Now can I refer you to page seven of your 23 Schedule B, and this shows the 24 telecommunications category, and can you 25 advise the Board what this category includes?

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1 A. The telecommunications category is \$120,000 2 and that's less than one percent of the total 3 budget. We have 340 mobile VHF radios in 4 service and we replace about 20 of those 5 radios each year, as they become unreliable. 6 As well, this project includes teleline 7 isolation equipment at several of our 8 substations, and this equipment is required to 9 improve the safety for utility and 10 telecommunications workers from the 11 possibility of high voltages that may occur on 12 telecommunications circuits in substations. 13 Q. Can you please give us an overview of the 14 general expenses capital? 15 A. The general expenses capital is \$2,800,000. 16 General expenses capital is the amount of 17 Newfoundland Power's administrative expenses 18 that are charged to capital, and it is 19 calculated in accordance with P.U. Order No. 3 20 (1995/96). 21 Q. Now could I ask you to refer to page nine of 22 Schedule B? This shows an allowance for 23 unforeseen items, and can you advise the Board 24 of the purpose of this allowance? 25 A. The unforeseen allowance is \$750,000. This	1 allowance is necessary to cover any unforeseen 2 capital expenditures which have not been 3 budgeted elsewhere. The purpose of the 4 allowance is to permit the Company to act 5 quickly to deal with unforeseen events in 6 advance of seeking the specific approval of 7 the Board. 8 Q. Mr. Delaney, do you have any concluding 9 remarks with regard to the 2004 Capital 10 Budget? 11 A. I have described a number of capital projects 12 that are needed to serve the new and existing 13 customers with reliable power supply that is 14 consistent with least cost. These projects 15 have been developed and prioritized through a 16 budget process that involves our front line 17 employees, such as line persons, hydro plant 18 operators and industrial electricians. The 19 process involves our engineers and our 20 technical personnel, as well as the managers 21 and the executive of the Company. 22 And I'll close by referring the Board to 23 the picture on the front cover of the 24 application. This is a number of line crews; 25 you can see six in the picture, and they're
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1 working in the Codroy Valley on the Doyles 01 2 feeder reliability project last year. This 3 was a successful, safe and a very productive 4 job, and as an anecdote, one of our linemen 5 commented that we did six years of work in six 6 weeks. So to have that good productivity on 7 the job, we need good planning, and this 8 budget application contains the planning 9 necessary for the prudent and successful 10 deployment of our capital resources in 2004. 11 Thank you. 12 Q. Thank you. Mr. Chair, that's the conclusion 13 of the presentation. I would propose to 14 provide copies of the slides which have been a 15 part of this presentation, and would propose 16 to have them marked as Exhibit EAL-1. 17 Thank you, Mr. Chairman. Mr. Ludlow and 18 Mr. Delaney are now available for cross- 19 examination. 20 CHAIRPERSON: 21 Q. Thank you, Mr. Myles. Mr. Young. 22 MR. YOUNG: 23 Q. Thank you, Mr. Chair. Good morning, 24 gentlemen, Mr. Ludlow and Mr. Delaney. I'd 25 like to start, if I might, with a general	1 MR. YOUNG: 2 question about the process Newfoundland Power 3 goes through in the Capital Budget. Perhaps I 4 could refer you to NLH-1, please. 5 CHAIRPERSON: 6 Q. What was that reference again, Mr. Young? 7 MR. YOUNG: 8 Q. NLH-1, request for information. 9 CHAIRPERSON: 10 Q. Fine. 11 MR. YOUNG: 12 Q. There's two concepts there which I'd like to 13 discuss a little bit, and the first is the 14 preliminary engineering reviews and design, 15 and the other is detailed engineering. I 16 wonder if either of you, and I'm really not 17 fussy as to which one chooses to jump in and 18 do this, but if either of you could please 19 explain the difference, as you see it, as this 20 works in your company? 21 MR. LUDLOW: 22 A. Mr. Chairman, there's a fundamental difference 23 in both, and I would take you back to one of 24 the projects that was described in--Mr. 25 Delaney described it actually, was the Water

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1 Street underground as an example. If I were 2 to go back to the early '90s, in particular 3 '92/93, there was an identification of a 4 concern starting to grow with respect to the 5 condition of plant, with respect to the 6 condition of the cabling, what we call the 7 potheads to joiners and so on, and we knew 8 that there was something had to be done in the 9 Water Street area, and the initial thought 10 process that we went through in subsequent 11 years, until we filed--I do believe it was in 12 1999, we were doing what I would call general 13 concepts in engineering at that point in time. 14 More along the lines of we knew that we had an 15 issue, the easy way out of this would be to 16 simply pull out one switch and put another one 17 back in. However, when we filed, we filed, 18 and I do believe it was '99, it might have 19 been 2000, but it was in that general range 20 before this Board in a capital hearing, and we 21 identified the problem and we basically laid 22 out what we would see as the general cost 23 parameters at that point in time to address 24 the issue. Subsequent to the approval of the 25 generic engineering and the project coming	1 forward, we then would immediately roll into 2 what I would call detailed engineering. And 3 by that, what we would do is we would take the 4 section that would be developed in the project 5 that was put forward at that point, a multi- 6 year project or multi stages. We would take 7 the section, we would look at what is the best 8 solution, what is the most cost effective 9 solution, what is the most customer friendly 10 solution, and what is the best engineering 11 design that would fit that, and now you're 12 down to CAD drawings, you're down to 13 specifications, you know, on switch gear or 14 civil works, and now I'm getting right down to 15 what I would call, to use my terminology, the 16 brass tacks of the task at hand, and that 17 would occur sometime between, in this case, 18 now and the actual construction, which would 19 be next July. So that's the differential, Mr. 20 Young, or Mr. Chairman, that I would use in 21 that, and that's an example that we would go. 22 Q. So just want to clarify that, generally 23 speaking then, the detailed engineering in 24 projects of that sort is done after the 25 capital budget item has been approved?
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1 (11:48 a.m.) 2 A. That's generally the case. We do not have, 3 and we've stated this clearly here many times, 4 that the line item detailed engineering has 5 not been completed. However, we have done, I 6 would take it to the feasibility level. I'd 7 almost look at it as ranges of comfort. The 8 job must be done. We know some of the 9 solutions, but we haven't scoped in detail all 10 of the respective solutions. Any capital 11 project that we put before this Board, Mr. 12 Chairman, again, is subject to continuous 13 review prior to execution. Namely, if in fact 14 it has to be done will be revisited at the 15 time of any expenditures, and that's a 16 statement that we've always gone forward with. 17 Q. Just a little further on that page you talked, 18 and Mr. Delaney had mentioned this this 19 morning, touched upon it at least, a couple of 20 concepts we'd like to know a little bit more 21 about. One is justification categories and 22 the other is priority codes. I'm just 23 wondering exactly what they are. I think we 24 have some sense now of what the priority codes 25 are, but how that fits into the process?	1 MR. DELANEY: 2 A. If I could refer the Board, in terms of 3 priority code, if I can refer the Board to 4 Volume 3, distribution, Appendix 2, Attachment 5 A. We have here our distribution inspection 6 and maintenance procedures and this particular 7 document drives a component of our 8 reconstruction project and our feeder 9 upgrading project, which is under "rebuild 10 distribution line." In this document, on page 11 five, we have our classifications of 12 priorities and the people that do the 13 inspection on the distribution feeder will 14 identify deficiencies and list them in this 15 order of emergency--the table indicates 16 emergency, priority one, priority two, 17 priority three, which with a recommended 18 response time. Now in further detail, if we 19 can go along in Appendix 1, we've broken that 20 down. Appendix 1 in the same report, three 21 pages on from there, to give our employees 22 some indication, in terms of the different 23 components of the distribution system, what we 24 would consider an emergency, a priority one or 25 priority two. For instance, in conductor

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1 damage, just to take one example out of the 2 list, our guideline, if there is more than one 3 quarter of the strains broke in a conductor, 4 that's an emergency, let's get something done 5 immediately. If there's less than a quarter 6 of the strains--a conductor is made up of 7 numerous strains--less than a quarter of those 8 broken, priority one and priority two. So 9 this is some indication of the priority that 10 we put on some of our capital work. 11 Q. Question occurs to me about, if I can go back 12 for a moment--sorry to bounce around here, but 13 back on detailed engineering issue, and I 14 don't think we need to turn to it, but the 15 report in Volume 2 about the New Chelsea 16 plant, there's a fair bit of money in that 17 project and I understand that once this is 18 done, there's supposed to be a significant 19 number of years expected from New Chelsea 20 without further capital expenditures of any 21 great amount. I wonder if you could 22 characterize that report? Is that detailed 23 engineering or is that prior to that? That's 24 the feasibility plus? I wonder if you could 25 just give some real terms in that context?	1 MR. LUDLOW: 2 A. Mr. Chairman, where I would categorize the 3 report being referred to that's presented 4 before this Board, this would be at the plant 5 assessment and feasibility and acknowledgement 6 of how we would, in fact, have to move with 7 this plant to keep it viable to run. To take 8 that and move it to detailed engineering, 9 we'll get down to the decisions that are 10 highlighted within this report. If you wish, 11 it's energy supply, Appendix 1, is where the 12 report is. Might be just as well to go there. 13 MR. DELANEY: 14 A. Appendix 2. 15 MR. LUDLOW: 16 A. Sorry, let me straighten that out. It's 17 Appendix 2, Energy Supply, Volume 2. 18 Q. Attachment A. 19 A. Attachment A. 20 CHAIRPERSON: 21 Q. Appendix 2 you say? 22 A. That's correct, yes, sir, Mr. Chairman. 23 Appendix 2, Energy Supply, Attachment A. This 24 is the New Chelsea plant refurbishment 2004 25 report, which is a further consolidation of
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1 multiple reports, mechanical, civil, 2 electrical. I think that would be the piece. 3 That's basically, Mr. Chairman, is a condition 4 assessment. It would be both on all those 5 fronts. It would go into detailed 6 assessments, for example, into ultrasonic 7 testing of the steel portion of the penstock, 8 showing that it's less than or approximately 9 50 percent of the steel remaining in places. 10 So it's that condition assessment. The 11 estimating that is done is based upon our past 12 experience in work in hydro plants. But 13 getting to the detailed engineering here, 14 whether we use fibreglass, steel or woodstave 15 and what the exact routing, the routing most 16 likely would stay the same, and down to the 17 drawings of that has not been completed at 18 this stage. The governor, whether it's 19 hydraulic, electric, electric hydraulic. We 20 know that the decision must be made, but that 21 fine detail has not been engineered at this 22 point in time. Similarly, with the controls, 23 that's been highlighted here as well. But the 24 feasibility stage has taken us here. The 25 judgment had led us to this point, and that's	1 MR. LUDLOW: 2 the distinction between the two. If - 3 MR. YOUNG: 4 Q. No, I think that's a full explanation. I 5 wonder if I could refer you next to a 6 different area. It's NLH-3, and the project 7 in question here is the hydro plant facility 8 rehabilitation. I understood, Mr. Ludlow, in 9 last year's hearing, Newfoundland Capital 10 Budget hearing, we had a brief conversation 11 from this format about the beauty of old hydro 12 plants and that they usually are long paid for 13 and the incremental capital costs required to 14 keep them safe and reasonably reliable is 15 small, incrementally small, and that provides 16 good low cost power. I think you'll probably 17 recall that conversation. 18 A. I agree with you. 19 Q. In this RFI, there is an example given here in 20 relation to the question about sometimes the 21 difficulty of dealing with projects of this 22 sort in analysis in a quantitative basis, and 23 the example given is Pierre's Brook. I 24 understand that in Pierre's Brook, you know, 25 the issue is the--at some point, at least,

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1 there's a safety issue because it's a penstock 2 headgate. But I also notice that there is a 3 reference to the number of gigawatt hours of 4 annual production. I'm just wondering, is the 5 reference to the annual production there for a 6 particular reason, insofar as there's a 7 concern if the penstock headgate is not 8 repaired that you might lose production for a 9 full year? Is that why the annual figure is 10 given? 11 A. Specifics as to why the 25.3 gigawatt hour 12 reference is made in NLH-3, it would not be 13 for that reason. It would be here to give an 14 example of this is the energy output of this 15 plant. The headgate is a very vital part of 16 this system. This headgate is--I've got the 17 number. It escapes me right now. Just bear 18 with me one second. That headgate is 1931 it 19 was installed, and it is a vital part, from a 20 safety perspective, for that area, for that 21 plant. Now do I do my justification on a 22 \$91,000 headgate expenditure back against 25.3 23 gigawatt hours? No, but I would have to say 24 that I've got some significant safety issues 25 on a 70-year-old headgate that's not working,	1 and that headgate is vital. You mentioned 2 safety. I'm not willing to put a price on a 3 person's life, and I don't think that's your 4 indication, Mr. Young. 5 Q. No, certainly not. 6 A. And that becomes that balance. If we were to 7 overhaul Pierre's Brook top to bottom, that 8 being dammed, penstocked, the whole thing, we 9 would do the same type of process through 10 inspections, what we've seen, dam safety 11 inspections, where this has come from, bring 12 it forward and consolidate it into a report. 13 So I don't know if I've answered your 14 question, but it's there to give a level--this 15 plant is a valuable plant to our system. 16 Q. So in this instance, did the number of 17 gigawatt hours, that's really just a 18 descriptor to give us some idea of the size of 19 the plant. I'm just wondering if we can move 20 to another one, by way of example, and we've 21 already touched on it this morning, the Morris 22 plant, and the questions that I had, I suppose 23 if we want to have a reference, it's in Energy 24 Supply, Appendix 1, Attachment B. This would 25 be what Mr. Delaney spoke about this morning
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1 and showed us the pictures. The project is 2 the turbine and stationary seal, little over 3 \$100,000. Just so I understand, this is a 4 relatively recent plant. It's about 20 years 5 old? Is that correct? 6 MR. DELANEY: 7 A. The date of manufacture, as shown in the 8 report, of the turbine is 1983, so it's 20 9 years old, yes. 10 Q. Where is this located? This is on the 11 Southern Shore, Morris? 12 A. That's on the Southern Shore, yes. 13 Q. Yes. Now in Attachment B, it says that the 14 plant is about 1100 kilowatts capacity and you 15 get 7.2 gigawatt hours annually. It's a 16 fairly high capacity plant, around 75 percent, 17 but that's not terribly germane to the issue. 18 The justification on page 305, that would be 19 in Schedule B--no, it would not. 20 CHAIRPERSON: 21 Q. Where did you reference, Mr. Young? 22 MR. YOUNG: 23 Q. I'm having a little bit of trouble finding my 24 reference here, but I certainly remember the 25 words, because, as is the case with a lot of	1 MR. YOUNG: 2 these things, they're in one place or another. 3 I don't need to go right to that reference 4 right for the moment, but the justification 5 relates to the reliable production of energy 6 from this facility and I think this morning 7 you spoke about the problems with the wicket 8 gates operating sluggishly and not getting 9 optimum production. Is that correct? Are the 10 turbine runner seals critical to the safety in 11 the same way that the penstock headgate is in 12 the Pierre's Brook thing? I take it it's a 13 different kind of an issue. 14 A. It would be, you know, a different kind of an 15 issue with respect to safety, but I wouldn't 16 feel too comfortable knowing that the wicket 17 gates were sticking and we have problems with 18 internal corrosion of the turbine, from a 19 safety perspective. 20 Q. And I'm not suggesting that we shouldn't do 21 otherwise but to make sure that the hydro 22 plants operate efficiently. I just want to 23 make sure it's that sort of an issue. Is 24 there any concern about these seals failing 25 completely or is it a matter of fixing them to

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1 optimize production? If they fail completely 2 in some way, completely got stuck and caused a 3 real problem for the way this work, would that 4 essentially require the plant to be shut down 5 and some sort of emergency basis? 6 A. If the seals, the wicket gates failed 7 completely, yes, that would cause a shutdown 8 of the plant. 9 Q. Okay. Do you have any idea how long that 10 would take to repair? 11 A. How long it would take to repair if - 12 Q. Yes, you know, the job you're - 13 A. - a catastrophic failure or - 14 Q. Yes. No, I guess my question relates to, you 15 know, you're planning to do this work to fix 16 this problem and when you plan to do work, of 17 course, you can optimize your schedule, you 18 can do it at a time when the plant perhaps can 19 be taken out of service with the least impact. 20 If it was required to be done because it 21 happened at a time which wasn't optimum and 22 you had to go in and do that repair, would it 23 be a different period of time? 24 (12:03 p.m.) 25 A. If the unit were to fail unexpectedly, it	1 would take much longer to do it, under much 2 more stressed conditions than if it were to be 3 repaired in a planned, organized fashion. 4 MR. LUDLOW: 5 A. Mr. Chairman, one of the topics in this area 6 in particular, if I may help, some point of 7 clarification to add to this, is that if that 8 wicket gate failed during spring run-off, 9 depending on where that wicket gate went, an 10 example being last year, we had a major 11 catastrophic failure at a Seal Cove plant. We 12 were out of commission. Just put the safety 13 at one point, loss production at another 14 point, the lost productivity of the workers, 15 organization and planning being a third point, 16 and Mr. Young, I don't know if those are the 17 points. 18 Q. Yes. 19 A. But as you put all that together, this becomes 20 a real serious problem. What we're dealing 21 with with these seals here, I mean, it's been 22 identified, we're putting water through. This 23 is an upstream plant from a downstream 24 producer, memory escapes me. It may even be 25 Pierre's Brook actually or one of those
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1 plants. 2 MR. DELANEY: 3 A. It's upstream from Mobil. 4 MR. LUDLOW: 5 A. Mobil. And what's happening, that's a flow 6 through plant. That's the reason the load 7 factor is so high. Now if we're putting water 8 through that plant and not maximizing the, I 9 use the term electrical engineer speaking, 10 value per gallon, but then, I think our 11 efficiency loss as a result of this stuck 12 headgate is a real issue for us, and hence, 13 the reason that this has been put forward, and 14 it is a concern. There's continuously people 15 going back and forth to that plant as well. 16 Q. I was just trying to narrow in on the 17 justification here and certainly the evidence 18 you've given this morning is helpful. From 19 the point of view of looking at this 20 quantitatively, insofar as it can be done 21 here, I notice in NLH-7, and I don't know if 22 we need to refer to it, but you refer to a 23 5.13 cent per kilowatt hour value of increased 24 Holyrood production that's avoided essentially 25 every time you keep--that's per kilowatt hour	1 MR. YOUNG: 2 figure, that's avoided every time you keep a 3 hydro unit running and producing a kilowatt 4 hour, and I accept your point about energy you 5 produce prevents, or not prevents, that's 6 certainly not the right word, allows Hydro to 7 produce less at Holyrood and relatively equal 8 amounts and almost whenever it occurs. Simple 9 arithmetic for me, this is 7.2 gigawatt hours 10 of annual production that this plant, roughly 11 \$350-370,000 a year. I don't know if I know 12 yet whether or not an assessment has been done 13 as to how much energy would be expected to be 14 lost if, in fact, this project wasn't done and 15 failed or, indeed, for that matter, how much 16 would be expected to be lost with this project 17 if it just has to be taken out of service for 18 the job to be done. 19 A. Whether that has been done--Phonse, do you 20 want to take this? 21 MR. DELANEY: 22 A. No, you go ahead. 23 MR. LUDLOW: 24 A. On that topic, I don't have that number with 25 me, Mr. Chairman, but there's a combination of

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1 factors, as I did go forward and say a few 2 minutes okay. This is in place. We're 3 continuously fighting to reduce the oil 4 consumption in this province. We have a plant 5 in place that we know has an identified 6 problem of a stuck wicket, and I watch the T 7 and the D in that word all the time, wicket 8 gate. We know there's an issue there and it 9 should be dealt with. Now whether or not that 10 gets replaced with stainless or with the 11 extruded something or other, I forget the-- 12 there's other types of metals, that may be 13 decisions that would come at that point in 14 time. That number may have been calculated. 15 I just don't have it with me. I'm sorry. 16 Q. No, no, that's fair. Other thing I notice 17 from the report which is at Attachment B to 18 Energy Supply, Appendix 1, the report's dated 19 April 12th, 2000, and that, I think, appears 20 to be, when you read the report, that's about 21 the same time that the problem was first 22 noticed, and the report was done probably 23 immediately, and here we are in the 2004 24 Capital Budget hearing and it's scheduled to 25 be done. So obviously it wasn't done right	1 away, it was deferred for a number of years. 2 I'm just wondering if you could explain to me, 3 from the point of view of capital budget 4 process, how it is that this project became a 5 2004 project and not a 2003 or 2005 project, 6 for that matter, an earlier project? 7 A. Well that being the case, I guess if we look 8 at how we actually go through the Capital 9 Budget process, that might be helpful, Mr. 10 Young, if I may, and I'll take you--the 11 reference, I do believe is NLH-1, is your key 12 driver on that area. Let me just get myself 13 straightened up here a bit. And from that, I 14 may be able to throw some light onto how we 15 proceed with this. As we run the business and 16 a Capital Budget process is, I look at it as a 17 dynamic exercise. It's ongoing continuously. 18 It's ongoing while we sit here today. There 19 are inspections occurring, there are projects 20 being identified or deficiencies identified. 21 Now, whether that's back to a priority where 22 it fits, that would be based upon engineering 23 judgment and would be based on the judgment of 24 the independent, individual departments. Let 25 me just take you back into the budget process,
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1 if I may. We start with the energy forecast, 2 customer and energy forecast. That's one of 3 the key drivers. Usually that's produced by 4 the rate's group and so on, and actually it 5 was filed in GRA in this first quarter. From 6 that, we produce then the customer driven 7 accounts, these being the services, meters, 8 extensions and what have you. We also have a 9 look at the system from a load capacity 10 perspective; hence, the Corner Brook 11 transformer, last year it would have been the 12 Virginia transformer and the Fowler's Road 13 transformer, Chamberlains, so that's the 14 second piece of that exercise. On top of that 15 we look at the system from a reliability and 16 what is underperforming within the system, so 17 that's a third block. And finally, we input 18 the system inspections or observations that 19 come through and hence, the field inspections 20 and so on. This is where this one would have 21 turned up. Now out of that then, these are 22 basically brought together, formal process 23 would go probably second quarter and is pulled 24 together at the departmental level within the 25 organization. And it is at those meetings of	1 MR. LUDLOW: 2 the various departmental managers to see where 3 it fits in relation to how do you weigh, for 4 example, the runner at--or the wicket gates at 5 Morris back against the Wesleyville 02. And 6 those are the balances and all while trying to 7 find the balance of the budget, and the 8 request for budget stability, balance with 9 price, safety and environment. And that 10 becomes the challenge as it comes through. So 11 with respect to its level and a priority 12 number, there is no priority number assigned 13 to it, but I would go so far to say that this 14 in pursuit of water use, is water going down a 15 pipe that we're not getting energy out of. 16 The people of this province is not getting the 17 use of that water. That's the general process 18 from beginning to end, bringing in the market, 19 bringing in inspections and what have you. 20 Q. Do you have any sense of how much--and I know 21 this can be a difficult calculation sometimes, 22 but do you have any sense of how much energy 23 you're losing from this plant? 24 MR. DELANEY: 25 A. No, we have no calculation on that.

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1 Q. Okay, so it's difficult to justify, I guess, 2 if you don't know exactly what you're losing 3 as to how much you'd be saving if you do the 4 work, correct? Now I recognize this is not a 5 large plant. 6 MR. LUDLOW: 7 A. I didn't say we don't know what we're losing. 8 I said I don't know what we're losing--excuse 9 me for correcting you. 10 Q. Well let me put it this way, I don't know what 11 you're losing either, and I don't know if the 12 analysis here provides that. 13 A. The assessment of this project is based upon 14 the original design that would have been put 15 in place for the Morris development upstream 16 from Mobil. We know they were having trouble 17 and in the past few years getting the output 18 that was designed. There is a lost production 19 factor. I just don't know what it is. 20 Q. So does that mean when you're running at full 21 gait, you're not getting name plate 22 (phonetic)? 23 A. That, I would suggest to you, is that--I don't 24 know if that's what it means, but what it 25 means to me is that what we were getting in	1 1985/86 at full gait, we're not getting in, 2 say, 2003 at full gait because the wickets are 3 stuck. 4 Q. So it's an inefficiency problem. But you 5 don't have today for us what that number is - 6 A. I just don't have it here with me. 7 Q. - or to make an assessment as to what the loss 8 production is. I'm just wondering, I touched 9 upon this a moment ago, I'm not sure if I got 10 an answer and I know it's another one you may 11 not have at the top of your head, but perhaps 12 you can discuss it in a qualitative sort of 13 way to give the Board and the parties a sense 14 of how this works. There is a difference 15 doing a planned capital job and doing one when 16 absolutely it becomes something has to be 17 repaired. Normally, like planned capital jobs 18 you can time it, you can phase it, you can do 19 other work at the same time, you have crew 20 mobilization advantages, et cetera. I'm just 21 wondering can you give some indication of what 22 that might be for a job like this, just to 23 give us a flavour of it. 24 A. Job such as Morris? 25 Q. Well, yes, you know, as opposed to having to
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1 go in and sort of in the middle of the winter 2 or having to go in at a time when the water is 3 higher and you're spilling more, that sort of 4 thing. 5 A. Okay, let me try. 6 Q. Morris might not be a good example for this, I 7 realize. 8 A. Let me take Chelsea, if we go - 9 Q. Yes. 10 A. - and try that one. If we lost the penstock 11 in Chelsea this afternoon, we've got one 12 enormous series of issues to deal with. We 13 have a roadway, we have houses, we have a 14 building. I haven't even mentioned the energy 15 on that end of the business, so if we go in 16 and look at the civil works, the electrical, 17 the mechanical and the civil I would put under 18 the penstock and dam work under it as well. 19 So now you organize and plan when you take 20 your plant out of service. You set your 21 contracts, you project manage, you have one, 22 maybe two project supervisors on site. Now, 23 if I were to run these as three or four 24 separate projects, what I'm into is I'm into 25 mobilization and demobilization, multiples of	1 MR. LUDLOW: 2 supervision, plus the back office planning, 3 scheduling and ordering, that gets all tangled 4 up. When you go now, you do one job. In line 5 work, I would suggest to you that the factors 6 are multiples. Mr. Delaney referenced the 7 line person in the Codroy, a quote was 8 actually made to me and it was sort of an 9 anecdotal comment. When a lineman goes to a 10 job today, he goes to do line work. He do not 11 go to do labour work or stores work or 12 anything else. I want that person in the 13 pole, wrench in hand; that's where he earns 14 his keep. It is not driving back and forth to 15 the job. It is not going to get a nut here or 16 a bolt there, he should be packaged at the 17 pole. That is what creates the productivity. 18 In that case, I would put factors of up to 19 three times as efficient, if not more. So 20 there are multiples. 21 Q. Just before we leave the Morris project, I 22 have one other question on that. And this is 23 on page 3 of 5, by the way, there's a 24 reference here, Appendix 1. I think this has 25 already been explained. "Since therefore to

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1 ensure the reliable production of energy from 2 this facility, the equipment must be 3 replaced." I just want to clarify, there is 4 no reliability issues for customers arising 5 out of an outage at this plant, correct? 6 MR. DELANEY: 7 A. Which plant are you referring to? 8 Q. Morris plant, 1100 kilowatt plant. 9 A. No, there would be no outages to customers as 10 a result of outage to the Morris - 11 Q. It's a reliability relating to the production 12 from this plant and not in relation to 13 interruptions of power quality. 14 A. The reliability of the plant itself, the plant 15 producing power. 16 Q. I guess I just have a couple of more questions 17 about this, just to clarify. This is a fairly 18 young plant. Once this work has been done, do 19 you expect to do much more on this plant in 20 the foreseeable years? I think you had that 21 answer somewhere else which suggests that 22 there isn't an awful lot more forecast here, 23 in this plant, is that right? 24 A. There is another RFI, I'm not sure if it was 25 asked, but -	1 Q. NLH-6, I think it is. 2 A. NLH-6, which I think indicates, if I get my 3 numbering here, indicates a \$50,000. 00 4 expenditure in 2006 and a \$17,000. 00 5 expenditure in 2007. 6 Q. I'm just wondering, still on NLH-6, the 7 \$50,000.00 in 2006 and the 17 in 2007, I'm 8 assuming they are problems or issues or 9 matters--I won't call them problems or issues 10 if in fact they're not, but they're probably 11 just the future capital requirements in 12 relation to this plant that have been either 13 determined by inspections or by a concern of 14 the useful life of something being known. Is 15 that right? I'm just wondering how those 16 future amounts would have been known at this 17 point and isolated to those figures. 18 MR. LUDLOW: 19 A. I don't have the actual detail behind the 17 20 or the 50, but I will, Mr. Chairman, say very 21 clearly that these plants, by their very 22 nature, will require some level, I'm going to 23 say capitalized maintenance on, I know I use 24 the term "oxymoron" in this every time I say 25 it, but a 20 year old plant that's running
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1 with moving parts, the only thing I can be 2 guaranteed is something will go wrong with 3 that plant, somewhere down the road. I do not 4 have the details of the 50 or the 17. That 5 could be road work or it might be a building 6 door or something of that type, but it's not 7 substantive that it would be brought to my 8 attention at this point in time. The way we 9 would typically do these, as we did with 10 Chelsea, Mr. Chairman, is to take the future 11 capital stream and any corresponding decrease 12 in operating expense as a result of it and 13 work those back into the pricing model as to 14 how it affects the energy. And that's 15 basically what's been done out over the 25 16 years back in Chelsea, as an example. And we 17 test those on those types of basis. 18 Q. Just further on that RFI, there are other 19 amounts for other projects mentioned there, 20 and I'm not asking you to detail any of these, 21 I'm just trying to get a sense of whether some 22 of these might have also fallen into the 23 category, as did Morris, of something that 24 popped up from an inspection and you know 25 you're going to have to deal with others,	1 MR. YOUNG: 2 maybe, of the sort you just referred to. The 3 general mix, I don't know if you can give us 4 any flavour for it, would it contain all of 5 those kinds of issues and all of those kinds 6 of ways of determining capital projects? 7 (12:20 p.m.) 8 MR. DELANEY: 9 A. As we said, we don't have the exact details of 10 every project in front of us, but I can speak 11 at a higher level on some of what's going on 12 here. If we take some of the bigger items 13 through to 2005 onward, for instance the Cape 14 Broyle expenditure, Petty Harbour, up around 15 the 800,000 range, those are projects that we 16 foresee in the future related to upgrading the 17 protection and control systems at the Hydro 18 plants, similar in nature to the protection 19 and control system at the New Chelsea plant. 20 You're dealing with 40 to 50 year old 21 technology that's electrical and mechanical in 22 nature and these two particular projects 23 pertain to the replacement of hydraulic 24 electrical mechanical equipment with digital 25 and electronic equipment as it reaches the end

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1 of its useful service life, and in many cases, 2 beyond its useful service life. So that's the 3 nature of the bigger ticket items going out 4 into the future. 5 Q. Just a point of clarification, I wonder if I 6 could refer to NLH-5 for a second and the 7 table that's attached to it. And the question 8 from that--perhaps I can go back to the 9 question--first I'll just read it. How much 10 capital investment has been expended on each 11 of Newfoundland Power's hydro electric 12 generating plants and their associated 13 terminal stations since 1992? And I just want 14 to clarify, the table that's attached would 15 give values which are similar to the general 16 hydro plant facility rehabilitation. That 17 doesn't include all the projects you've done 18 on these plants, is that correct? For example 19 the Lockston penstock is not there? 20 MR. LUDLOW: 21 A. That's correct. 22 Q. So if we were to ask that question, I don't 23 know if we change the wording of the question, 24 but we would need other numbers in relation to 25 the larger projects which you single out for a	1 special treatment in those years. Okay. 2 A. Mr. Chairman, this table presented in NLH-5 is 3 a statement on the project of hydro plant 4 facility rehabilitation and the way we have 5 been presenting to this Board and as we have 6 done today, some of these projects have been 7 rolled up with subcategories within, which is 8 the hydro plant facility rehabilitation being 9 an example, but where there are large projects 10 that requires attention to be brought to bear, 11 such as New Chelsea, the Lockston, Cape 12 Broyle, Horsechops, I can't remember the other 13 ones offhand right now, that would be separate 14 from this table. 15 Q. So this is not the total amount of 16 expenditures, but it's the total under this 17 category? 18 A. It's the total under the hydro plant facility 19 rehabilitation project title as presented in 20 the application. 21 Q. Thank you. They are distinct from 22 refurbishment is the point you're making. 23 A. Exactly. And, you know, rather than just 24 Petty Harbour itself, this is what's been 25 under this project in Petty Harbour.
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1 Q. I wonder if I could refer you to NLH-7 for a 2 moment. And the discussion there in relation 3 to Rattling Brook, this is one we discussed to 4 some degree this morning already in direct 5 testimony. I understand there's a job there, 6 a little over \$400,000.00 for a generator pre- 7 wind, correct? 8 MR. DELANEY: 9 A. That's correct, yes. 10 Q. Just to put this in context, Rattling Brook, 11 that's in Central Newfoundland, located about 12 where? Flows into the Exploit's, I think, 13 does it not? 14 A. The Rattling Brook plant is located in Norris 15 Arm in Central Newfoundland. 16 Q. And as Newfoundland Power plants go, this is a 17 fairly large one, 11.4 megawatts and almost 70 18 kigawatt hours annually. And I notice the 19 amount of money you stated in annual terms of 20 the value of the energy is roughly three and a 21 half million dollars. I'm just wondering, I 22 think you mentioned that the rewind of the 23 generator that's already failed took about 8 24 months, is that correct? 25 A. That's correct, the generator took 8 months to	1 MR. DELANEY: 2 rewind, the one that's already failed. 3 MR. YOUNG: 4 Q. Do you have much storage at this plant? 5 A. Yes, there's a considerable amount of storage 6 at Rattling Brook. I don't have the numbers 7 right off, but it does have storage. 8 Q. Okay, and the load factor or the capacity 9 factor is around 70 percent, so I assume that 10 often times, but not all the time, one of the 11 two generators could carry the--particularly 12 where you have some storage, one of the two 13 generators could carry the requirements by 14 running that one, essentially flat out, 15 perhaps not its most efficient loading, but 16 you're not spilling an awful lot of water if 17 you have one of the two generators up and 18 running, is that correct? 19 A. For certain times of the year, we can run the 20 plant with one generator, but that wouldn't be 21 true for parts of the year when we have 22 considerable water, say in the spring, when we 23 would require two generators to produce energy 24 at this plant. 25 Q. What's the nature of the operation of this

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1 plant? Is this a plant that is able to 2 generate all the water it gets or is it some 3 inevitable spill? 4 A. This plant, you know, again I don't have the 5 full history of this plant in front of me, but 6 our experience that I'm familiar with is this 7 can basically use all the water that's 8 available to it. 9 Q. Did you spill much when you did the other 10 generator? The eight-month period that the 11 other generator is out, do you know if you 12 spilled much water at that time? 13 A. No, we didn't spill any water--any appreciable 14 amount of water when the generator faulted 15 last year. Now, - 16 CHAIRMAN: 17 Q. Did that take in the springtime? 18 A. It actually faulted right after the spring run 19 off when we hit the dry season. So let's say 20 we were fortunate. 21 Q. You got lucky. 22 A. Yeah, well--that it did not occur in the 23 spring or in the tail part of the winter. The 24 fault occurred during--after the spring, so we 25 mobilized, got the rewind work done. It's	1 probably--this is a good example of doing work 2 under unanticipated conditions verses planned 3 conditions as well, because the project costs 4 associated with rewinding that generator under 5 the emergency conditions was in the 6 neighbourhood of \$650,000, but our estimate 7 here now in terms of doing it in a planned 8 function, rewinding the sister unit, the 9 identical unit, is in the \$400,000.00 range. 10 MR. LUDLOW: 11 A. Mr. Chairman, I actually was in Rattling Brook 12 when we were coming, pretty well ready to come 13 back on line last December, and it would be, I 14 would put it, might be off by a week, but I 15 would suggest around the 10th to the 15th of 16 December. And I know at that point in time, 17 with the rains that had been coming on, we 18 were pretty much at the top of the dam. And 19 the question was now, if this don't come back, 20 we're spilling water and that becomes the 21 challenge. To carry it over, both January and 22 February and we always get a January thaw 23 anyway, seems to be, and coming through 24 spring, that basically would have spilled 25 water with one unit available. That's where
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1 MR. LUDLOW: 2 it would be. 3 MR. YOUNG: 4 Q. So you were--well I guess you're never 5 fortunate when a generator needs to be 6 rewound, but you were fortunate in that 7 instance because of the timing, you didn't 8 spill water, as it turned out. I guess the 9 extra cost that hit you which you have just 10 well explained, Mr. Delaney has well 11 explained, was about a quarter of a million 12 dollars of extra cost because it happened at a 13 time that you weren't able to plan it and do 14 it in an orderly fashion. The other numbers 15 in NLH-7 that relate to the amount of money, I 16 mean, I don't know if you can point to any of 17 those numbers in relation to the energy 18 generation from the plant that pertained to a 19 particular out-of-pocket expense that the 20 Company suffered due to loss generation or 21 anything of that nature, is that correct? You 22 know, for example, you're talking about the 23 1.8 million dollars in annual purchase cost 24 that's saved because you have, you know, one 25 of those units up and running or not.	1 MR. LUDLOW: 2 A. I'm sorry, I'm misplacing, your question is 3 not sinking with me, Mr. Young. If you could 4 try once more for - 5 Q. Okay, let me try that again. In the third 6 paragraph of the answer to RFI NLH-7, there's 7 a number of dollar values thrown around there. 8 One is the total amount of kigawatt hours and 9 what that relates to in money, so at 69 10 kigawatt hours a hour, three and a half 11 million dollars, and then you say that the 12 generator that's going to be rewound is 13 responsible for roughly half of that. 14 A. That's right. 15 Q. And the arithmetic is done for us there. And 16 you also quoted the dollar figure you're using 17 for energy that shows where the math comes 18 from. But from the point of view of 19 justification, in the generator rewind you 20 did, and I'm not suggesting for a moment that 21 you shouldn't do this on a planned orderly 22 basis, but for the generator rewind you did, 23 you can't demonstrate from these numbers what 24 the real savings are to the customers from 25 doing this rewind on the basis of a planned

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1 orderly way, verses doing it whenever it 2 fails, which is the alternative which, I 3 suppose, we wouldn't want to choose. 4 A. Well, Mr. Chairman, running any rotating 5 equipment at the end of a six foot penstock 6 run to failure, there's a big question of 7 engineering judgment and prudent operation has 8 to come into play. And the fact that we ran 9 this at 47 years, you know, that's the reason 10 I'm here today presenting this second winding. 11 We have tested this second winding, we got 12 caught, it failed, effectively is what 13 happened. I've got another unit, same age, 14 same duty cycle, up to this point. The 15 testing is outside the parameters of the new 16 coil, plus plants of similar vintage, is all 17 indicating that we are heading towards eminent 18 failure. So, to shut it down and run the 19 spillage question, that, to me, is not the way 20 to run that plant. We have an installed 21 plant, that's, you know, the--well, that's 22 producing 70 GWhs a year. It's a very 23 valuable asset. That operating expense alone, 24 on that plant, the operating cost of our 25 plants is between .5 and .6. That's the	1 operating, not the capital. All in, that 2 would be much, much less. The number, I got 3 it here somewhere, I can dig it out on 4 Rattling Brook, is in comparison to the 5.1 5 and hence our ability to keep the cost down to 6 our customers. As an engineer, I'll take my 7 executive hat off for a minute, run to failure 8 should not be the premise to operate. It is 9 to find the right time to when you move in, 10 when you don't go in. No one wants to replace 11 equipment early. I certainly don't. I've 12 been challenged an awful lot on that in the 13 past. But I will say running something to the 14 point that it fails and breaks, that's not my 15 way of operating, I'm sorry. 16 Q. No, and I'm not suggesting it ought to be. 17 I'm just curious on the, just further on that 18 point, I suppose, I notice that the other 19 generator rewind was done in 2002. It wasn't 20 an emergency proposal for 2003, so it's 21 engineering judgment that brings this into 22 2004, is something which you're trying to 23 avoid, this eminent failure, is that correct? 24 A. What we have done on that end, Mr. Chairman, 25 is the fact that this was identified, the
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1 testing is complete, instructions are out to 2 our energy supply department to adjust the 3 duty cycle on this second unit and to bring it 4 in line, where possible, put the pressure on 5 the other unit. That's the type of operating 6 procedures we're trying to get in place to 7 take us over the next year to levelize. It's 8 that kind of balance to carry through. Can we 9 do that? I don't know. But that's what we're 10 going to try to do. 11 (12:34 p.m.) 12 Q. Further on the point you just raised. You 13 mentioned about the--you had some readings 14 done and I think the information provided is 15 that the readings didn't provide conclusive 16 proof of an eminent failure, so you 17 supplemented that because of your recent 18 experience with your engineering judgment, is 19 that correct? 20 A. No question, that is correct, Mr. Chairman. 21 The ultimate testament is a failure and we 22 lost our coils, so what do we do? We then 23 have to try and assess, test through non- 24 destructive means the quality of the installed 25 plant. Now, you take all of that and put it	1 MR. LUDLOW: 2 together and a person or persons, 3 professionals in that field that work with 4 small hydro, aged hydro, you combine that with 5 utility or production standards that are out 6 there of 40 years on the coils. We're already 7 at 47. We put all of that together, hence the 8 decision. It is the judgment basis that comes 9 into this one as well. 10 MR. YOUNG: 11 Q. I just wonder if we can, before we leave 12 Rattling Brook, I wonder if we can put it in 13 some context. It's a large, largish plant for 14 a small hydro, 11.5 megawatts. Were one of 15 the units to trip because of this problem in 16 the middle of, you know, running at a time 17 when the energy requirements were fairly high, 18 would that cause, by itself, customer outages 19 or would it likely just be absorbed as a bump? 20 A. If we were running the plant full out? 21 Q. Yes. 22 A. That would be about 11 megawatts - 23 Q. No, well I'm thinking that you would probably 24 just lose half if one of the generators went, 25 yeah.

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1 A. If we lose one, we lose say, whatever it is, 2 half of 11, 5.7 I guess, whatever, that, in 3 itself, should not result in lost customer 4 uptime; however, it could have impact on the 5 transmission line reliability in the area, but 6 it would not result in sustained customer 7 outage. 8 Q. I wonder if I could refer you to NLH-14, this 9 is the New Chelsea protection and control 10 equipment project that I'm interested in at 11 this point, which is a project of, I think, 12 it's just under a million dollars. And one of 13 the, well the second paragraph there, the 14 second full paragraph says, and I'll just read 15 it, "The governor functions reasonably well 16 when operated in parallel with the grid, but 17 does not regulate well when operated in 18 isolation from the grid; therefore the 19 generator is less reliable during emergencies 20 that arise when the transmission system is 21 unavailable." I wonder how often the plant is 22 called upon to serve customers in the New 23 Chelsea area on an isolated basis? Has that 24 occurred many times in the past? 25 MR. DELANEY:	1 A. I don't have the figures in front of me as to 2 how often, but I spent some time out there as 3 manager of that area, in Avalon and I can 4 assure you it happens at least once a year and 5 it may--there may be more than that. What we 6 had done in the New Chelsea area is a radio 7 transmission line that serves two substations: 8 New Chelsea and Old Perlican. And the line, 9 this radio line is in the neighbourhood of 45, 10 47 years old, so it does require maintenance 11 from time to time. So what we're able to do 12 down there during the summer months is run our 13 New Chelsea and Pittman Pond plants, keep the 14 customers on, keep the power on and take our 15 transmission line out and do some maintenance 16 on it to keep the reliability up on the line. 17 So as to exactly how many times that occurs 18 per year, I'm not sure. It does and it does 19 at least once because I know we've done 20 maintenance on these transmission lines 21 basically annually, and as well, if this 22 transmission line were to fail unexpectedly, 23 the New Chelsea plant would be available to 24 keep power on to the New Chelsea, at least to 25 a portion of the New Chelsea and Old Perlican
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1 systems, depending on the time of year and 2 what loads were there. 3 Q. I'm not sure I fully understood your question 4 (sic.). Did you say that you sometimes run 5 these plants for planned maintenance? 6 A. Yes, we would run the plant, the New Chelsea 7 plant for planned maintenance on a 8 transmission line. 9 Q. So it avoids having to send, for example, a 10 mobile there in those times. You have the 11 plant, you're up and running and you can use 12 that. 13 A. Exactly. It would avoid sending a mobile as 14 well as it will enable us to do more work in 15 the amount of time available. If you are able 16 to take the line out of service, de-energize, 17 take the voltage off the line, you can do much 18 more work for the amount of time available as 19 opposed to doing the work during energized 20 conditions. I showed a slide in my 21 presentation of linemen working on a job on a 22 transmission line while it was energized, with 23 all the orange hot line gear. So that's kind 24 of much longer to do the same amount of work. 25 So in New Chelsea that's one of the benefits	1 MR. DELANEY: 2 of having the plant there. 3 MR. YOUNG: 4 Q. The protection control equipment that's sought 5 to be replaced though, is it just being 6 justified--I think the answer is no to this, 7 perhaps you can just confirm it, it's not just 8 being justified on the basis of running the 9 system, an isolated basis, correct, this is 10 essentially an added advantage to having it 11 upgraded so that it could run in a stable way, 12 appropriate levels of voltage and frequency 13 when the system is running on an isolated 14 basis. 15 A. Yes, it is an added advantage. This 16 protection control system is being replaced on 17 the basis that it's 48 years old and it's 18 beyond its useful service life. 19 Q. NLH 15, I wonder if I could refer you to that 20 and I'm not really sure what the answer means 21 exactly. The question is, "Has there been 22 plant outages caused by the New Chelsea Hydro 23 Plant protection control equipment" and the 24 answer is, "Yes, there's been 92 plant 25 outages, trips and lockouts related to

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1 protection and control equipment over the last 2 five years." Those 92, would some of those 3 relate to the protection and control equipment 4 operating correctly and isolating the plant in 5 order to avoid a problem that had originated 6 somewhere else, for example, on the 7 transmission grid, or would they all be, 8 essentially, failures of the equipment to 9 operate properly? 10 A. These would be instances where the equipment 11 did not operate properly. We had problems at 12 the plant caused by the equipment that is 13 installed there to protect and monitor the 14 plant. These are not instances of, you know, 15 the protection operating properly. 16 Q. Referring now to NLH 16 and the question 17 relates to really customer outages caused by 18 this equipment. My understanding of the 19 answer is that customer outages are not really 20 the problem, it's a power quality issue, is 21 that correct? So you are able, generally 22 speaking, it says no document on instances in 23 recent history, causing customer outages but 24 the concerns are raised and it's in the report 25 about power quality, so it's that level of	1 concern, is that right? 2 A. Yes, exactly. When the New Chelsea plant is 3 required to operate what I would call isolated 4 from the system, and so those instances are 5 when we're doing planned maintenance on the 6 radial transmission line that serves the area 7 or in the event that we lost the radial 8 transmission unexpectedly in a storm, and the 9 New Chelsea plant operates separate from the 10 grid and can provide some limited amount of 11 power to the customers in the New 12 Chelsea/Winterton area up to Old Perlican and 13 Bay de Verde. But there is a problem of power 14 quality when that happens. And the problem is 15 in terms of the frequency, you know, all 16 appliances. The electrical system is supposed 17 to work on 60 hertz and the New Chelsea plant, 18 because of its, you know, its old protection 19 and monitoring system, its old electrical 20 controls has trouble maintaining that 60 hertz 21 cycle while it operates in isolated mode. Of 22 course when New Chelsea is connected to the 23 grid, then the 60 hertz frequency is provided 24 by the grid. 25 Q. So I suppose if this problem deteriorated
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1 further, you would have no choice for planned 2 maintenance, but to move a mobile to that 3 site, is that correct? 4 A. If the - 5 Q. For example, it's sort of a hypothetical, but 6 if this project wasn't approved and the PLT 7 equipment wasn't changed and you had a planned 8 maintenance situation somewhere down the road, 9 you might be forced to move a mobile generator 10 to that site in order to do that maintenance, 11 which could probably cause you troubles in 12 some other project you may be trying to carry 13 out, is that the level of concern? 14 A. That would be a level of concern. If we were 15 to determine that, you know, it would be 16 impossible for New Chelsea to provide proper 17 frequency while it operated isolated from the 18 grid, we would in order to--we would have two 19 alternatives; either do the maintenance hot, 20 line of--or three alternatives really; do the 21 maintenance hot while the line is energized; 22 take the power off and have planned scheduled 23 outages for the customers while we did the 24 maintenance; or we could move portable 25 generation. Now that would be after	1 determining that New Chelsea could no longer 2 MR. DELANEY: 3 supply the local load, supply the proper power 4 (unintelligible) for the local load. 5 MR. YOUNG: 6 Q. As I understand the answers to your RFI, the 7 issue we've just been discussing about the way 8 that the plant can operate to revive power in 9 the local areas when isolated, is not the real 10 reason that this protection controls equipment 11 has to be fixed, it's actually a bigger 12 problem isn't it? It's the obsolescence 13 issue, is that correct? 14 A. That's correct. The justification for the 15 replacement of the protection control at New 16 Chelsea is based on the obsolescence. This is 17 48 year old equipment. We have protection 18 equipment that's designed to protect the plant 19 that's causing the plant to trip on 92 20 occasions in the last five years. It's beyond 21 its useful life. 22 Q. In NLH 17, there's some discussion with some 23 specific information about some problems 24 you're running into, obtaining and maintaining 25 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 acid 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.	(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 it 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, lost cost. Hydro plants by their nature are reliable but they will not be reliable if we put in and maintain it in a	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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1 Q. I notice from your answer in NLH 17 there also 2 seems to be a concern about the compatibility 3 of the older technology and as you explained 4 it, it is fairly old technology. With the 5 other upgrades you're planning to do, so I'm 6 just wondering can you elaborate on that a 7 little bit further. 8 MR. LUDLOW: 9 A. As I said earlier, as we look at the detailed 10 engineering and I look at Chelsea as an 11 example, there are seven potential contracts 12 that will be let from this, the bulk of which 13 will go to local people or local Newfoundland 14 companies. Electrical and mechanical, as the 15 tie in between the governor and the governor 16 controls the wicket gates which controls the 17 speed which controls the water flows which 18 controls how fast that turbine spins 19 effectively is what it's doing. And how we 20 tie all that together could be a concern. 21 It's way over my intellectual capacity to get 22 down in too much detail there, Mr. Young, on 23 that one. But what happens--we wouldn't 24 change it simply for the sake of changing it. 25 If we can piece together two technologies and	1 make it talk and work, we will. That can 2 cause problems, have caused problems. As a 3 matter of fact there's a project in this 4 budget along that lines at Topsail. When we 5 get to the detail engineering, if there's a 6 part that's good, a part that we can keep, 7 I'll scavenge it for that plant and keep it 8 going, but I want 25 to 30 years out of it. I 9 don't want to be back here in two years 10 recoring or rewinding or redoing the bearings 11 or something because there's a relay that I 12 didn't put in or didn't talk properly. That's 13 the connections between the complexities of 14 technologies. 15 MR. YOUNG: 16 Q. Just further on that same project, NLH 18, if 17 I could refer you to that, please. And the 18 response to this question indicates fairly 19 clearly that final design hasn't been done and 20 these numbers are sort of round and rough and 21 we're not sure which of these two types of 22 governors we're likely to choose, is that 23 correct? 24 MR. DELANEY: 25 A. Yes, that's correct. There's two alternatives
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1 we're looking at and like Earl said, this is 2 something we will leave to the detailed 3 engineering as we get into New Chelsea. And 4 the two alternatives are approximately equal 5 in cost. I think one is about 60,00 US and 6 the other is about 70,000. 7 Q. I gather that there are--at first blush, and I 8 understand these numbers are not final, but at 9 first blush you appear to be favouring the 10 \$70,000 proposal even though it's not least 11 cost and it's the other recommendations or 12 these other comments that you're making that 13 favour it that way, is that correct? I just 14 want to get a flavour of what the purpose is 15 because we understand the least cost is 16 generally the rule unless there's a reason not 17 to go least cost. 18 MR. LUDLOW: 19 A. Least cost is not cheapest. It's a point I'd 20 like to make clear. And it is very important 21 for everyone to recognize we're dealing with a 22 hydro plant sitting on a former river that has 23 a tail race that's going into Trinity Bay. 24 Now, in looking at least cost versus price, 25 there's a whole bunch of things going to have	1 MR. LUDLOW: 2 to creep in here. We're going to have be 3 talking maintenance, we're going to be talking 4 environment and all those other strange 5 factors, Mr. Chairman, that become very 6 important in that decision. So I certainly 7 wouldn't want to leave the Board with the 8 impression that we're going with a \$70,000 US 9 item and not worry about the ten. That's not 10 what this is. The whole piece of this would 11 be taken into account. That governor has 26 12 gallons of oil in it. Now what value do I put 13 on that 26 gallons of oil. I don't put much 14 on it if I've got it contained and I'm sure 15 that I can control it. But if it loses and 16 gets into the bay, I'm in trouble. And that's 17 the reality of where we have gone in 18 sensitivity. So, sorry, to correct you, Mr. 19 Young, but I it's a point that I think is 20 necessary to be made. 21 MR. YOUNG: 22 Q. Okay, I'm not sure I was corrected because I'm 23 not sure we disagree. 24 MR. LUDLOW: 25 A. We're finally agreeing.

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1 Q. Yes. I think the point I was trying to make 2 and I think you've probably spoken to it is 3 that, you know, these costs, as you say, and 4 face value, they're not equal. And I'm not 5 suggesting long term have the same value as we 6 look at here on the page. One is 70, one is 7 60. And you said--you made a distinction 8 between least cost and cheapest. 9 A. That's correct. 10 Q. I think I understand that, and the question I 11 asked, Mr. Ludlow, was whether or not it was 12 these other factors and I think you've just 13 explained some of them, that would lead you to 14 believe that perhaps what appears to be least 15 cost in the long run won't be, and that's the 16 sort of analysis that gets brought to this. 17 A. I think very well your synopsis of my piece is 18 very well done. 19 Q. There's no disagreement on some of these 20 points. I'm just wondering, and this is a 21 small point really, but it goes back to the 22 first thing I asked you this morning about the 23 process and the stage in the work where the 24 detailed engineering design will make this 25 decision, just for further clarification on	1 that. Right now you have two basic models to 2 work with or two basic approaches you have for 3 this governor. I believe one is sort of the 4 older technology and one is the newer one. 5 And the difference in dollar value is not 6 huge. What sort of factors do you anticipate 7 might swing it when you do the detail design, 8 is that the fine tuning of the numbers or is 9 it something else like an extraneous factor 10 which will become more important? 11 A. Mr. Chairman, I think it's a combination of 12 both. The way we have traditionally done 13 these, particularly Tors Cove and some of the 14 other plants is it's not a one of anything. 15 We will engineer what our requirements are and 16 we will go to market for that. From there 17 though we learned that--I don't want to say 18 the governor--but specific niche areas within 19 the market has a lot more expertise in this 20 area than probably anyone in our province. So 21 we asked for a given design to be met, a 22 specification, but we also go and ask for 23 alternative options and bring to bear, in the 24 case of this one--let's be hypothetical, Mr. 25 Young, if I may. Let's say we went to
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1 Woodward governor, I mean what are my other 2 options in today's technology that can 3 mitigate these extraneous factors and can I 4 get them in and down under these layers of 5 dollar, where do they come. So it's a factor 6 of actual cost, what am I getting for the 7 price I'm paying and there could be, I'll use 8 the word extraneous because I used it before, 9 but they're real costs. Oil today is a real 10 issue, particularly if you deal with hydro 11 plants. So putting all that together, the 12 value of that plant, as well in dealing, 13 running remotely in New Chelsea, Hant's 14 Harbour, Old Perlican areas, any governor is 15 going to do that for us. So the combination 16 we do the specifications up front but we would 17 also go to market and ask for those to be 18 verified and checked with alternate options 19 that come back from the marketplace. 20 Q. I think my last question relates to--we'll 21 have to go to NLH 5 to see it. Just bear with 22 me for a second. Yes, that's where it is, on 23 that table. A few moments ago, Mr. Ludlow, 24 you mentioned that you ordered the oxymoron of 25 capitalized maintenance, as you called it.	1 MR. YOUNG: 2 And when I glance at this table, one number 3 jumps out at me is--well I just don't expect 4 to see a number that small. There's a couple. 5 The one I'll focus on for now is 2001 Cape 6 Broyle, capital investment is \$25. And I'm 7 just trying to make some sense of a number 8 that small being deemed capital and how that 9 pops up. What could possibly so small as to 10 be \$25 and not be just a routine maintenance 11 issue. Must be US funds. You know, I don't 12 know if this is perhaps a question we should 13 put to Mr. Perry. 14 A. I'm not even sure I'd put that to Mr. Perry. 15 Sorry, I have no idea what would be a \$25 16 capital expenditure in a hydro plant. I can-- 17 you know, we look at these, we follow the 18 rules that have been provided to us under 19 capitalization and offering, you know, the 20 units of property and all those things, tools 21 greater than \$1,000 or capital, that one don't 22 fit. I'm running all these in my mind. I 23 don't know. Unless it was a carry over from 24 2000 and got into a late invoice that was 25 associated with that, that's a possibility,

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1 that got in 2001. 2 Q. I said it was my last question, I guess it was 3 my second last. There's a similar issue, 4 although it's a very different dollar value 5 amount, I'm sure, which relates to the 6 radiators on the transformers and I'm not 7 going to turn to it because I don't know if I 8 could find it right off the top. But in one 9 of your projects you're replacing a lot of 10 radiators that you're having significant 11 trouble with and they're treating that as a 12 separate capital project. I'm just curious 13 and please tell me to defer this to another 14 witness if you think it's appropriate for me 15 to do so, but is the radiator different or a 16 piece from the transformer which is separate 17 as a unit of property? I would have thought a 18 radiator is part of the transformer and that 19 that would be under maintenance normally. 20 (1:04 p.m.) 21 A. Two things on that front, if I may, assist and 22 I'll probably hand off the detail to Mr. 23 Delaney because I'm getting, pardon the pun, a 24 little rusty on this myself, Mr. Chairman. In 25 the 60s and 70s there were substantive design	1 changes went into the radiators on power 2 transformers. Some of them used to be the big 3 pipes that came out. Then in about the early 4 70s there were crest radiators or the 5 radiators were flat pinned, much, you know, on 6 a large scale, similar to a car radiator in 7 that they were folded and pressed, thin metal. 8 And that was through, say, I'll give it ten 9 years for rough range to get the picture out. 10 In 1980, late '79, '80, it became very evident 11 that we were experiencing rust on these units. 12 You can't grind them very far, obviously 13 because of the very nature. You're extracting 14 heat by blowing cold air through a radiator. 15 In 1980 we changed our standard specifications 16 for power transformer purchase to specify 17 galvanized radiators. So I'll start there. 18 Thirty years ago when we bought these 19 transformers, they had pins on them and we've 20 been maintaining them through, you know, 21 monthly inspections, then we go in every three 22 years and overhaul them. We're in there again 23 in six years to keep them going. The 24 radiators identified are at the end of their 25 useful life. However, without a radiator, a
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1 transformer is useless. So I have two 2 options. I can get rid of the transformer 3 which to me would be not a prudent activity or 4 alternatively, I can buy a new radiator, 5 galvanized radiator, attach it and extend the 6 life of my asset. And it will extend it quite 7 substantially. And hence the reason we've 8 capitalized those radiators and these would be 9 pre 1980 units. If there's anything you can 10 add - 11 MR. DELANEY: 12 A. No. What Earl said, the nature of a radiator 13 is you just can't buy one component of the 14 radiator. And the process we've gone through 15 to repair them is we use sort of a plastic 16 polybond type of thing to plug the leaks and 17 monitor it. So, you know, the manufacturers 18 provide the radiator as a complete package. 19 And these are not small projects, to replace a 20 radiator. We got four in the budget for 2004 21 in the capital application. They range in 22 prices from 81,000 up to 122,000 and it's a 23 complete component. It will extend the life 24 of the substation transformer. It has an 25 enduring benefit so we consider that a capital	1 MR. DELANEY: 2 expenditure. 3 MR. YOUNG: 4 Q. Those are all my questions. Thank you Mr. 5 Ludlow and Delaney. 6 CHAIRMAN: 7 Q. Thank you, Mr. Young. Mr. Kennedy? 8 MR. KENNEDY: 9 Q. Thank you, Chair. I wonder if we could just 10 deal with one project in particular, I think 11 that might take us close to the hour and a 12 half and that's the New Chelsea project. And 13 the best place to go to is Volume II under 14 "Energy", Appendix II, Attachment A. And 15 there's--this attachment has a number of sort 16 of sub documents and the one I'm looking at 17 first is I think the second one under the-- 18 after the first blue page and it's Appendix A. 19 So it's Volume II, "Energy", Appendix II, 20 Attachment A, Appendix A and it's titled, 21 "Site Assessment Protection and Control." For 22 what will amount to a brief question it was-- 23 the digging to get the document is going to be 24 longer. On page two of that Protection and 25 Control site assessment there's battery plant

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1 and charger and it's indicated that the 2 batteries are in good condition, that the 3 battery bank was replaced in 1996. Then he 4 goes, "The charger was installed in 1975 and 5 should be replaced due to unavailability of 6 spare part." I guess that sort of triggered 7 off the general question about what the policy 8 is there for Newfoundland Power when 9 considering whether to replace a piece of 10 equipment of this nature. There's no 11 indication there that the charger is not 12 operating in accordance with required 13 specifications. I'm wondering why thought 14 wouldn't have been given to just maintaining 15 the charger despite its age, instead of 16 replacing it at this point? 17 A. I'm not use to working with a panel, Mr. 18 Kennedy, I'm sorry. Okay, I'll start the 19 answer, if I may. Mr. Chairman, just to give 20 a little overlay, batteries run the power 21 system. The alternating current does not run 22 the power system. All controls, all 23 instrumentation and those, all, that's 24 definitive, but by far, the majority of relays 25 and all of these, what I would call	1 intricacies within a power plant or a 2 substation is run on battery power. The 3 reason being, you need it when the power goes 4 out. You got to have some way to bring it 5 back up, hence your batteries. Now, that's an 6 explanation to why there's batteries. Now, we 7 go to the fact that the battery charger is 8 obviously an important part to keep the 9 batteries charged up. Now, this here, we're 10 saying there are no spare parts available, 11 okay. So, if we're going in to complete-- 12 we'll keep the batteries, the batteries will 13 stay, the charger, again, if we're going in to 14 do this job which is our proposal, then why 15 would we keep a vital piece of equipment that 16 is no longer repairable, other than by 17 scavenged part or scrounged parts, that does 18 not make a whole lot of sense, to run your 19 system in that way. That's the only point I 20 would make. Do we have a policy on this? 21 This might last another six months, it might 22 last one year, but we know that it is already 23 28 years old and a battery charger operates 24 24 hours a day, it's continuously plugged in and 25 running. So, when I leave that plant next
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1 year, the objective is to have the plant in 2 excellent operating condition. So, I don't 3 have to be back here in 2005, 2008 and 2010 4 with small--hopefully not \$25.00 expenditures, 5 but very low level expenditures back in that 6 plant again. Hence, the reason that we change 7 this point, Mr. Kennedy. 8 Q. Okay. So, there's no evidence that it's not 9 operating properly? 10 A. If it was operating properly, we--improperly? 11 Q. Yes. 12 A. We would have it pulled out. 13 Q. Right. So, it is operating properly. The 14 device is doing what it's supposed to do, 15 charging the batteries. 16 A. Right now, that is correct. 17 Q. And you keep--I believe I saw that there's in 18 your budget, you keep spare battery chargers 19 on hand, do you not? 20 A. We do. 21 Q. I believe you've got four battery chargers in 22 your budget for being purchased this year? 23 MR. DELANEY: 24 A. Let me just have a look. 25 Q. I had the reference and now, of course, that -	1 MR. DELANEY: 2 A. Yes, it's substations, Appendix 2, page 2 of 7 3 which show the battery chargers that we plan 4 for 2004. 5 Q. And how many is it? 6 A. There are three 48-volt battery chargers and 7 two 120-volt battery chargers. 8 Q. Okay. So do you know which--what battery bank 9 we're dealing with at the New Chelsea plant? 10 A. Which battery bank? 11 Q. What size? Is it the 120 or - 12 A. I'm not sure what that is. 13 Q. In either event, you would, I assume it would 14 be one or the other? 15 A. Yes. I would hope, I would think. 16 Q. So you do have spares on hand in the sense of 17 a spare battery charger on hand that you could 18 use to replace the existing battery charger? 19 A. The battery chargers that we have in spare are 20 there to provide some degree of security to us 21 that should we have a battery go in any of 22 our--a battery charger go - 23 Q. Wait now, we're speaking about chargers, yes, 24 okay. 25 A. - battery charger go in any of our 137

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1 substations, all of which have battery 2 chargers and 23 hydro plants, all that have at 3 least one or multiple battery chargers. 4 Batteries are something that we pay a lot of 5 attention to in maintenance because as Earl 6 said, when the power is out, the thing that's 7 going to get the power back on is the 8 batteries. A substation or a hydro plant is 9 rendered useless without the batteries if the 10 power is out, of course, right. So, given the 11 contents of the amount of system that we have 12 there, the parts that you're referring to with 13 respect to spare battery charger is to handle 14 the whole system. We frequently, we run tests 15 on our battery chargers every month and those 16 that don't need our specifications are hauled 17 out of the system. We cannot have-- 18 particularly in substations--we can't have 19 batter chargers that are not working. 20 Q. I understand and that's your hypothetical and 21 I believe that Mr. Ludlow indicated if it 22 hadn't been performing according to your 23 requirements, it would have been taken out of 24 service prior to this. So, we know that this 25 charger is working properly up to this point.	1 We know that it itself can't be repaired due 2 to the fact that there's an unavailability of 3 spare parts. I guess it begs the question of 4 why not just leave it in service, let it live 5 out its useful life and in the event that it 6 does fail, you've got back ups on hand to 7 replace it with already, so that there 8 wouldn't even be any, presumably, delay in 9 delivery. 10 MR. LUDLOW: 11 A. These spares are not--all that equipment is 12 not simply sitting on a warehouse shelf 13 waiting to be used. I think that's a point of 14 clarification for this Board. This is a 15 continuous rotating inventory. As we check 16 these battery banks, check these--what do you 17 call them--the chargers, we may, in fact, use 18 these very quickly. I do not have a spare one 19 sitting there waiting to be used, okay. It is 20 that type of an inventory spare. If I took 21 out the one out of Chelsea, as an example, 22 that I know is 28 years old, would I put it 23 spare? No, I would not. That is not--if it 24 is operating today, the future viability of 25 that unit is at best, suspect.
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1 So, again, I come back - 2 Q. Only because of its age though? 3 A. Well, it can't give parts, there's something 4 wrong with it. It's 28 years old, obviously 5 the market didn't give up making them, Mr. 6 Chairman, simply because they are a great 7 product. Okay. So, let's be realistic in 8 that too. This stuff do wear out. So, if, in 9 fact, that battery charger fails after that 10 type of in-service life, my objective should 11 be and is not to run it to failure because 12 now, all of a sudden, I'm losing that 13 equipment, I'm dispatching people and I'm 14 again running my plant to breakdown. That do 15 not make operating logic. 16 Q. Well, a failure of your battery charger won't 17 cause breakdown of your plant though, correct? 18 MR. DELANEY: 19 A. You won't know that until, if you had an 20 outage and you tried to bring your plant back 21 up, then you find out if your battery charger 22 is not operating properly. 23 Q. Yes, but your batteries would be charged at 24 that point or if they weren't, you would have 25 realized that. If your batteries weren't	1 MR. KENNEDY: 2 charging, you would have gotten knowledge of 3 that prior to your plant shutting down, 4 correct? 5 MR. LUDLOW: 6 A. Possibly. 7 MR. DELANEY: 8 A. Not necessarily. 9 MR. LUDLOW: 10 A. This whole area of the battery charger, it is 11 an insurance blanket that keeps your batteries 12 running. That's what it boils down to, okay, 13 in this case. The battery charger here, to 14 boil this down, I have a 28-year old piece of 15 equipment, it is functioning today, if it 16 break tomorrow, I don't have any alternative, 17 but to replace it. Would I challenge my two 18 spares to put it into that, if I move this one 19 and put that--I put another one in spares, 20 then I'd be comfortable, then I would run 21 comfortable not from being overly rich, leave 22 that one there and give me another one for 23 spares because I need those two spares to run 24 my 138 substations and 23 hydro plants. 25 Q. One of which is New Chelsea?

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1 MR. LUDLOW: 2 A. Okay, well 22 hydro plants. 3 Q. If we could just go onto the next section, 4 actually a few sections away, it's Appendix C 5 under the same division that we're looking at, 6 Civil Work Site Assessment. And this is a 7 discussion about the condition of the 8 woodstave, penstock and the steel penstock at 9 New Chelsea. And over on page three in your 10 concluding paragraph, it reads, "in 11 conclusion, the woodstave, penstock has passed 12 its reliable service life and needs to be 13 replaced. It would have been expected that 14 the steel penstock would be good for another 15 20 to 25 years, however, investigations reveal 16 that the steel section has also deteriorated 17 to a condition where it must be replaced 18 before reliability or failure become an issue. 19 Based on the above, the entire penstock should 20 be replaced in the next year". 21 Now, if we look at the next document, 22 however, Appendix B which is the steel 23 penstock assessment, the second page of that 24 memorandum from Gary Murray to Gary Humby 25 dated June 16 of this year. And the third and	1 second last paragraphs that I want to read 2 from, third last paragraph on page two reads, 3 "in conclusion the internal and external 4 inspection of the penstock revealed that the 5 penstock is severely corroded and the 6 thickness is below the design requirements. 7 The deterioration of the pipes seems to be 8 more from the internal corrosion rather than 9 the external corrosion". It continues, "the 10 penstock may very well be pitted completely 11 through and leaking in some areas with 12 pressure rises in the pipe from normal and 13 emergency shutdowns at the plant. Penstock 14 leakage and resulting erosion of the bedding 15 material could become problems into the 16 future. While failure of the pipe is not a 17 concern at this particular time, the penstock 18 has passed its reliable service and should be 19 replaced in the near future". I wonder if you 20 could just comment on that first. I have 21 another question concerning this, but I guess 22 from a lay perspective, there seems to be 23 almost like a contradiction within that last 24 statement I read, "while a failure of the pipe 25 is not a concern at this particular time, the
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1 penstock has passed its reliable service 2 life", so how could the penstock have passed 3 its reliable service life if there's no 4 failure of a concern at that point in time? 5 MR. DELANEY: 6 A. Okay, then sentence is what it is in terms of 7 the report, failure, but if I look at the 8 context of the whole e-mail, I think it would 9 be important--if we go back and look at what 10 we actually did find in terms of the steel 11 penstock and the measurements that we did were 12 determined through ultrasonic testing. We did 13 a number of pit holes along with steel 14 penstock. Much of the penstock is actually 15 buried. And we found places in the penstock 16 where there was heavy pitting and wall 17 thicknesses from 3 to 10 millimetres. Now, 3 18 millimetre wall thickness is well below the 19 original 10 millimetre wall thickness that 20 this pipe was designed for. And the average 21 thickness--and I'm just picking up from the 22 fourth paragraph in the first part of the e- 23 mail, the average thickness reading in the 24 section below the manhole was 5.74 millimetres 25 and 4.43 millimetres above the manhole with	1 MR. DELANEY: 2 the average of all the measurements being 5.09 3 millimetres. So, we're dealing with a pipe, a 4 penstock steel pipe that has a wall thickness 5 half of its original design. Now - 6 Q. If I could just interrupt you for a moment, I 7 think if you read though the next two 8 sentences out, it actually says, the number 9 should not be interpreted as saying that only 10 half of the wall thickness is remaining. 11 A. Okay, for the entire section of the pipe, I 12 would assume that to be. I think if we look 13 at the context of the e-mail in total and 14 weave through the entire thing, we'll be left 15 with the impression that this is a good 16 project for 2004. And as a matter of fact, he 17 does--let me just read it here for a second. 18 The recommendation from the engineers is 19 replacement of penstock in the near future. 20 Q. The feasibility study that follows again after 21 that document, that Appendix E indicates that 22 the replacement cost for this steel portion of 23 the penstock is half a million dollars. 24 However, it's also indicated that the penstock 25 maintenance accounts for significant portions

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1 of the operating cost and the future costs
 2 after this penstock portion has been replaced
 3 would be reduced by \$5,000.00 a year. So,
 4 we're going to reduce the operating
 5 maintenance by \$5,000.00 a year with a half a
 6 million dollar capital expenditure.
 7 A. This project is not being justified on the
 8 basis of the operating cost reduction.
 9 Q. Well, I thought that's what the feasibility
 10 analysis was attempting to show, is that
 11 there's a net present value, if you will, to
 12 the project overall, but I'm just dealing with
 13 the penstock, the steel penstock itself.
 14 MR. LUDLOW:
 15 A. There's a couple of things happened here.
 16 First of all, I will speak to the steel, if I
 17 may, for a second and tie it back to what you
 18 were referring to, Mr. Kennedy. Mr. Chairman,
 19 when Mr. Murray investigated this penstock,
 20 with two things on mind, we've had a
 21 significant blowout of this pipeline, and
 22 actually while I was on the stand here last
 23 year, I actually was speaking in terms of
 24 Lockston and then we had one, I think it was
 25 November on the woodstave penstock at Chelsea

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

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1 that took a month to repair. The question
 2 that was being addressed regarding the
 3 reliability of the steel penstock here is the
 4 general condition. It's 48 years old, if this
 5 was pressing imminent rupture, that plant
 6 would be shut down today.
 7 Q. Are we dealing with the wood penstock or this
 8 steel penstock?
 9 A. I've gone to the steel now and I'm coming back
 10 to the others. We have not had a rupture in
 11 the steel, but the upstream wood has been one
 12 thing. As we investigated the steel and in
 13 the e-mail or the memo forwarded from Mr. Gary
 14 Murray to Mr. Gary Humby, both of which are
 15 professional civil engineers, well experienced
 16 in small hydro, they were asked to investigate
 17 the integrity of the steel. His reference, as
 18 I would interpret it, Mr. Kennedy, in your
 19 reference that there's no--where's it to
 20 there, just bear with me one second--"a
 21 failure of the pipe is not a concern at this
 22 particular time", that's the reference. I
 23 would hope not. At this particular time, if
 24 that was in failure, that plant would no
 25 longer be generating kilowatt hours and that's

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1 MR. KENNEDY:
 2 of this portion of planned refurbishment
 3 proposal on what alternative Newfoundland
 4 Power looked at as opposed to replacing some
 5 of the this equipment like the steel penstock.
 6 There's not discussion in the documentation
 7 about reviewing whether it made more sense to
 8 just continue maintaining that steel penstock
 9 for a time or whether repairs were possible to
 10 the steel penstock as opposed to fully
 11 replacing the steel penstock?
 12 A. That's fair.
 13 Q. Did Newfoundland Power consider those
 14 alternatives? And if so, why wasn't it
 15 included in the refurbishment report?
 16 A. The answer to your first question, the first
 17 question, Mr. Chair, is yes, they have been
 18 considered. With 20,000 plugs in this
 19 penstock already -
 20 MR. YOUNG:
 21 Q. In the steel one?
 22 A. No, this would be in the woodstave. The way
 23 they repair a leak is to use plugs to find
 24 plugs. I'm not sure what the right term is,
 25 but the term I use, they plim up and that

Page 161 1 means basically they swell up with the water 2 and they seal. Plus the frequency of the 3 blowouts that have been experienced on the 4 wood section, so that has been assessed. It's 5 the end of useful life, we cannot treat the 6 wood, Penta is not a friendly item to use. I 7 don't even know if you can get Penta, that's 8 what traditionally has been used, tars and 9 those type of wood preservatives on a 10 woodstave pipes. 11 Now, with respect to the underground 12 section of the steel, based upon what I have 13 been provided by my professional staff, it is 14 47 years old, there is substantive pitting 15 occurring and has occurred on the test fronts. 16 The time is right now to do this. It is 17 outside, it is 47--I don't have to repeat 18 that--47 years old. Can we get a year? It 19 makes no sense to split the project between 20 two and the also I am not, upon his 21 recommendation, willing to push this any 22 further than we've already pushed it. That's 23 the type of feel that I get across from it. 24 Why it's not in a report, I can't tell you, 25 sir, but I do know that before we go with	Page 162 1 this, we will assess steel, fibre and other 2 alternatives that the market can bring to 3 bear, whether it will be steel and wood, or 4 will it be all wood or all steel, that I don't 5 know because we have not completed the 6 detailed engineering civil works on this 7 project at this point. 8 Q. Thank you, Mr. Ludlow. Chair, that's a good 9 place to stop for today, I think, we were 10 scheduled to stop at 1:30. I have--there's 11 enough material that we really need to call 12 the panel back for tomorrow. 13 CHAIRMAN: 14 Q. Okay, thank you, Mr. Kennedy and I think as we 15 indicated earlier, we'll reconvene tomorrow 16 morning at 9:00 as opposed to 9:30. Thank 17 you. 18 MR. KENNEDY: 19 Q. Thank you, Mr. Chairman. 20 Adjourned at 1:30.
Page 163 1 CERTIFICATE 2 I, Judy Moss Lauzon, hereby certify that the 3 foregoing is a true and correct transcript in the 4 matter of Newfoundland Power's 2004 Capital Budget 5 Application, heard before the Board of 6 Commissioners of Public Utilities, Prince Charles 7 Building, St. John's, Newfoundland and Labrador on 8 the 10th day of September, A.D., 2003 and was 9 transcribed by me to the best of my ability by 10 means of a sound apparatus. 11 Dated at St. John's, Newfoundland and Labrador 12 this 10th day of September, A.D., 2003 13 Judy Moss Lauzon	