September 20, 2004
(9:59 a.m.)
CHAIRMAN:
Q. Good morning. I guess there's no doubt according to the screen what we're here to consider this morning. This is an application by Newfoundland Power to seek approval of their 2005 capital budget. I'd like to begin by introducing the Commissioners. On my left is Commissioner Gerard Martin and on my right is Commissioner Walter Vincent. I see Mr. Alteen is here and Mr. Hayes.
MR. ALTEEN:
Q. Absolutely.
CHAIRMAN:
Q. You're both here representing Newfoundland Power. Mr. Kennedy is representing or is Board counsel, Board hearing counsel and do we have any other intervenors this morning? No other parties interested in making any presentations or -
MR. KENNEDY:
Q. Chair, I would confirm just for the record that while Newfoundland and Labrador Hydro provided notice of their intention to

intervene in this hearing, they subsequently provided notice that due to their own time constraints and their upcoming capital budget, that they would not be intervening in this hearing.
CHAIRMAN:
Q. Okay, thank you, Mr. Kennedy. I also would like to introduce Cheryl Blundon who is the Board secretary and seated in the back of the room over in the corner is Doreen Dray and Doreen is the economic and financial analyst to the Board.

I would ask Mr. Kennedy now if you could put on the record, Mr. Kennedy, some of the matters that you normally put on the record at this stage.
MR. KENNEDY:
Q. Thank you, Chair. Chair, I can confirm that the Board has statutory authority to hear this matter pursuant to Sections 41, 78 and 80 of the Public Utilities Act. Before you is an application by Newfoundland Power for approval of its capital budget in the amount of $48,141,000. Also seeking the Board to fix and determine its average rate base for 2003

in the amount of $675,730,000. Approving its revised forecast average rate base for 2004 in the amount of $713,072,000 and approving its forecast average rate base for 2005 in the amount of $740,142,000. And approving revised values for its rate base and invested capital for use in its Automatic Adjustment Formula for the calculation of its return on rate base for 2005 pursuant to Board Order P.U.19, 2003. Can confirm as well the appropriate notices have been provided to the public in accordance with the Act and specifically, public notice of this hearing was issued to The Evening Telegram, The Western Star, The Northern Penn, The Labradorian, The Aurora and The Grand Falls Advertiser.

Rules of procedure governing the matter have been issued to the parties and unless the Board orders otherwise, they are the ones that would regulate the operation of the proceeding here today. I've already confirmed that Newfoundland and Labrador Hydro, although filing Notice of Intervention, subsequently withdraw or provided notice that they would not be intervening. I will indicate though

that they did request to remain on the mailing list so that the Clerk of the Board to take notice of that.

Finally, Chair, I wish to confirm that pursuant to their mandate as the Board's financial advisors, Grant Thornton have filed a report in the form of a letter dated September 15, 2004 just addressed to Ms. Doreen Dray with the Board of Commission of the Public Utilities, confirming that they have reviewed the items of the Newfoundland Power capital budget and provides specific commentary concerning that. It should be self-explanatory, but I would draw attention to the fact that as indicated in Grant Thornton's letter at page 6 of their letter, or page 5, I think it is, actually--yes, sorry, page 5 of their letter, the second paragraph they indicate that at the time of writing their report there were certain RFI's that were outstanding from Newfoundland Power, had not been replied to yet, not from any lack of effort on the part of the utility I might add. Everyone is aware it's a short time frame and at the time that Grant Thornton was

MR. KENNEDY:
requested to write the report and issue it, those RFI's hadn't come in yet. And they indicate in that paragraph that these requests were still outstanding at the time of the report and "we will review the responses when received and provide further comments on this item, if necessary." And it's my intention as Board hearing counsel to contact Grant Thornton and I'll ask them to confirm in writing so that it can be filed on the record that they have completed that review of the RFI's and whether there's any specific comments they wish to make. And I believe that's it, thank you, Chair.

CHAIRMAN:
Q. Thank you, Mr. Kennedy. Do you have anything to say in relation to anything Mr. Kennedy has said up to this point, Mr. Alteen?

MR. ALTEEN:
Q. I have a brief opening statement, Mr. Chair, but are we going to mark this letter by Grant Thornton and put it on the record. It's probably convenient for the purposes of housekeeping.

MR. KENNEDY:
Q. Yes, I would suggest that we--because Grant Thornton is not actually tendering it as an Exhibit, I was going to suggest that we put it in as a consent document -

MR. ALTEEN:
Q. We'll consent, Mr. Chairman.

MR. KENNEDY:
Q. So it's Consent No. 1, Chair.

CHAIRMAN:
Q. Before you get to your opening remarks, Mr. Alteen, I'd just like to finish up a few of the housekeeping items that I have. The procedure will be recorded and transcribed in the usual manner. Transcripts will be available, I would expect, tomorrow, Ms. Blundon, would that be fair? The sitting hours for today, and I don't know if the matter will go beyond today, Mr. Alteen, that pretty well entirely depends on you as to how long -

MR. ALTEEN:
Q. I wouldn't want to shortchange my friend, Mr. Kennedy in the whole affair, Mr. Chairman, but we will be hopeful to conclude it today. If

not, we would expect it to conclude in the morning.

CHAIRMAN:
Q. The hours, of course we started at 10:00. I propose we go to 12:30 and from 2:00 until 4:30. If there's any sign that we could finish this afternoon well then we'd be prepared to sit beyond that as opposed to coming back for an hour in the morning.

MR. ALTEEN:
Q. And we'd be committed to that schedule also, Mr. Chairman.

CHAIRMAN:
Q. And we'll have a break sometime around 11:15 this morning and sometime around 3:15 this afternoon. And since you have Power Point presentations and I wouldn't want to interrupt that, any let's say phase of that, we'll set the break at a time that's convenient giving regard to the flow that you want to maintain in your presentation, Mr. Alteen. Okay. There will be a complete record of the proceedings maintained by the Clerk of the Board and all of the exhibits and submissions that are to be presented should be presented

through her, so that a record is properly maintained. And having said that, unless there's any other preliminary matters, Mr. Alteen, are you prepared or ready to proceed with the presentation of your application?

MR. ALTEEN:
Q. Yes, I am, Mr. Chairman, I'll have a brief opening statement. Good morning, Mr. Chairman, Commissioners. The application before you today is essentially asking for three things. It's asking firstly for an approval of Newfoundland Power's capital budget in the amount of $48,141,000 and that is a Section 41 Public Utilities Act application and that section of the Act simply requires Newfoundland Power to bring forward its capital expenditures for the ensuing year prior to December 15th and that's the primary purpose we are here.

The second approval we seek, Mr. Chairman, is approval of the company's 2003 rate base. That is, application is made under Section 78 of the Public Utilities Act and that is sought for purposes of regulatory continuity. It is a matter of the Board's

MR. ALTEEN:
practice that it is approved, the previous year's rate base is approved at the next capital budget hearing, so there's nothing unusual there.

In terms of the third matter in which we seek an order, Mr. Chairman, it's the approval of revised values for rate based invested capital for use in the Automatic Adjustment Formula. The Automatic Adjustment Formula as Mr. Kennedy has indicated will establish the allowed return on rate base for Newfoundland Power for 2005 and that formula was approved by this Board at Newfoundland Power's 2003 General Rate Application. Mr. Chairman, that application is brought under Section 80 of the Public Utilities Act which is the fundamental entitlement of the utility to earn a reasonable return on its rate base.

Today, the Board shall hear evidence from three company witnesses, Mr. Chairman. The first witness will be Mr. Phonse Delaney, he's Newfoundland Power's Vice President, Engineering and Operations. He will speak to the majority of the expenditures in the

capital budget. He is the gentleman who has ultimate responsibility for the infrastructure of Newfoundland Power, the electrical system infrastructure and the maintenance, the operation and the construction of it. He will be using a Power Point presentation and you can see the first slide up on the screen. We anticipate that his presentation will be in the order of an hour so it will conveniently meet the schedule, Mr. Chairman, that you've indicated, give or take 15 minutes. That Power Point presentation has been filed with the Board, it was filed on Friday past. We may wish to mark it for the purposes of this proceeding and I'd ask Ms. Blundon now if it's a convenient time to mark it. Perhaps, PD NO. 1, seeing it's Mr. Delaney's Exhibit.

The second witness you're going to hear from today, Mr. Chairman, is going to be Mr. Peter Collins. He's Newfoundland Power's Manager of Information Systems. He will speak to the information technology expenditures proposed in the 2005 capital budget. This Board has heard from Mr. Collins for the last number of years and it's routine that we bring

in a specialist in information technology to speak to those expenditures because they tend to be a little out of the mainstream of those involved in maintaining, constructing and operating the electrical system.

The third witness today will be Ms. Lisa Hutchens, Mr. Chairman. She is Newfoundland Power's Vice President Finance and Chief Financial Officer. She will speak to the issues related to Newfoundland Power's 2003 rate base and the values needed for the operation of the Automatic Adjustment Formula on a go forward basis. On matters relating to the calculation of the 2003 rate base and the values that go into the formula, Grant Thornton has conducted its usual review and we've entered Consent No. 1 on the record. Mr. Chairman, Grant Thornton has found no discrepancies or unusual items in those calculations. So the calculations that directly affect the orders we're requesting have been already assessed by Grant Thornton to be reasonable. So Ms. Hutchens' testimony on this matter will be relatively summary. This will provide the Board with the

appropriate comfort so it can grant the orders requested on that line.

What we've asked Ms. Hutchens' evidence to focus primarily on in this proceeding, Mr. Chairman, is the issue of the amortization period for the unfunded liability associated with Newfoundland Power's defined benefit pension plan. And that's the very issue that Mr. Kennedy referred to that Grant Thornton had not had the opportunity to review up to the time of filing Consent No. 1.

In a nutshell, Mr. Chairman, this issue is before you today because the amortization period affects Newfoundland Power's rate base. As a result of the last General Rate Order of Newfoundland Power, deferred charges are now part of Newfoundland Power's rate base. So in addition to plant, the electrical system plant, what I would call mainstream capital expenditures, these deferred charges are in the rate base. And the predominant one is deferred pension cost. At Newfoundland Power's last capital budget, this issue was raised and Newfoundland Power was requested to come forward with a report on an appropriate-

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MR. KENNEDY:
-or the appropriateness of the current amortization period. Mr. Chairman, we're four or five years away from the end of a 25 year amortization period which commenced in 1984 when that pension plan was created. And that period we will not be suggesting be changed in any way. It is prudent and it remains in the benefit of consumers in terms of the long term, Mr. Chairman. All of this is governed by pension laws and regulations and involves accounting practices and Ms. Hutchens will go through that. Board staff have raised what I think is the essential regulatory question, is whether customers are well served by the current amortization or might they be better served by a longer amortization period.
Mr. Chairman, the staff's question is a reasonable one. Ms. Hutchens' direct evidence today will summarize Newfoundland Power's view on this and it will essentially set out and summarize what's in the record before you today. And part of that is in the report on deferred charges and rate base and the report on the amortization of pension funding which

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would have been filed with the application. And the rest is in the response to PUB-37 NP which is a detailed seven part information request from Board staff which deals with the matter in which Mr. Brushett is currently assessing.
Mr. Chairman, so there's no proposal to change the status quo. The status quo is in the customers' interest, it's the least cost way to deal with the unfunded liability. Nevertheless, Newfoundland Power thinks it's kind of important that we actually spend a half hour or 45 minutes going through that on the record, Mr. Chairman, in a public and a transparent way. And that's what Ms. Hutchens will principally be doing.
At the conclusion of the hearing, Mr. Chairman, I'm pretty confident I'll be submitting to you that the evidence before you in totality will justify the Board's approval in Newfoundland Power's 2005 capital budget in the amount of $48,141,000; the Board's approval of Newfoundland Power's 2003 rate base as filed, and the Board's approval of the revised values we used the Automatic

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Adjustment Formula. All is filed. Mr. Chairman, that concludes my opening remarks. I'd like to introduce Ms. Colleen Combdon who is the lady behind the screen over there and is providing us with the technical assistance and should there be any call or need to call up documents, obviously, you can direct that request to Ms. Combdon and she's fully able and competent to do that. And with that, Mr. Chairman, if there's nothing arising, it would be time to call our first witness, Mr. Phonse Delaney.
CHAIRMAN:
Q. Very good. Mr. Delaney.
(10:15 a.m.)
MR. ALPHONSUS DELANEY (SWORN)
CHAIRMAN:
Q. Carry on, Mr. Alteen.
MR. ALTEEN:
Q. Mr. Delaney, you are a professional engineer and the Vice President Engineering and Operations with Newfoundland Power?
MR. DELANEY:
A. Yes, I am.
Q. You have prepared or supervised a preparation,

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a Power Point presentation you are about to give to the Board?
A. Yes, I have.
Q. And you have supervised a preparation of all matters that have been filed with this Board relating to the engineering and operation of maintenance of Newfoundland Power's electrical infrastructure?
A. Yes, I have.
Q. And that includes a report filed in the principle filing and the responses to information requests?
A. Yes.
Q. And do you adopt the totality of this as your evidence in this proceeding?
A. Yes, I do.
Q. Mr. Delaney, would you give the Board a little bit of an idea of your background, please.
A. Good morning, Chairman and Commissioners. I have worked with Newfoundland Power for 17 years. During my career I have worked throughout the company. I've worked in Operations as an electrical engineer, I've been based in Stephenville, Corner Brook, Clarenville, Burin, Carbonear and St. John's.

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MR. DELANEY:
I've been involved in all aspects of engineering and operations of Newfoundland Power and as well, I've worked as a system planning engineer in some of our planning functions at our head office.
On the corporate level, I've led a number of initiatives. I've negotiated the operations and engineering practices of the Aliant pole deal, and I directed the out sourcing of telecommunications and transportation functions that are not core to our business.
Q. Mr. Delaney, thank you for your background. Now, would you please begin your presentation. And, Mr. Chairman, I've purposely not punctuated this with a lot of questions on the assumption that you'd rather hear from Mr. Delaney than me.
A. I will start my presentation by giving the Board a brief overview of Newfoundland Power. This map highlights our service territory. We serve approximately 222,000 customers in over 600 communities on the island portion of the province. Our system is comprised of over

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10,000 kilometers of transmission and distribution lines, approximately 250,000 poles, 137 substations and 23 hydro electric plants. We have employees and equipment positioned across the island in the 23 communities indicated on the map. We need to maintain a presence throughout the island to ensure good customer service for both our urban and our rural customers. Newfoundland Power is a capital intensive business. Over the years we have spent over one billion dollars to build this electrical system.
In this application, we are requesting the approval of the Board to spend $48,141,000. In the remainder of the presentation I will take the Board through these three items. First, I'll discuss the 2005 capital plan. That is a plan that we filed with this application. It's our long term plan that takes us out to 2009. Then I'll move into the specifics of the 2005 capital budget. Here, I will describe and explain the major projects that we have upcoming next year. And I'll finish with an explanation of the 2004 capital expenditure

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variances.
Q. Okay, Mr. Delaney, now would you take us to the 2005 Capital Plan?
A. The Capital Plan is contained in Volume 1 of the pre-filed application. In developing the plan, I was particularly mindful in two areas, two key areas; their affordability and deliverability. Affordability is top of mind, in that capital expenditure has an impact on customer rates. So it's therefore important that we exercise the prudent judgment necessary to balance the needs to maintain a safe and reliable power system with a goal of stabilizing rates through customers. And second, I'm mindful of deliverability. I want a budget that can be delivered and executed in a productive manner.
This is the chart contained on page 2 of the Capital Plan. The chart shows the historical capital expenditures from 2000 to present, as well as the forecast expenditures out to 2009. Given the extraordinary nature of the Aliant pole purchase, we've highlighted it to separate it from the overall total. Excluding Aliant, the capital expenditures

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have ranged from a low of $42.8 million in 2000 to a high of 60.3 million in 2003. And the company plans to invest approximately 252 million dollars during the 2005 through to the 2009 period.
The Capital Expenditures Plan from 2005 to 2009 are reasonably stable from year to year. We can see that in 2006 and 2007 there is some upward pressure. This is because of the large project in those two years to refurbish the Rattling Brook hydro plant, and I'm going to go into detail on that particular project later in the presentation.
This is the chart on page 3 of the Capital Plan. This chart shows our capital expenditures by origin, excluding the Aliant pole purchase. What I'm showing here are the main drivers behind the capital program. Note that there is a relative consistency from year to year among the various drivers of the capital expenditure and the drivers are listed below: the plant replacement, system additions, information systems, etcetera. What this chart clearly shows is the significance of plant replacement in its plan.

MR. DELANEY:
Approximately 60 percent of the capital expenditures are for straight plant replacements. That's about 30 million dollars per year spent on replacing the aging infrastructure and equipment of the power system. As I mentioned before, Newfoundland Power has spent over one billion dollars to build this electrical system and as this large and complex infrastructure continues to age, it deteriorates and as a consequence it will become less safe and less reliable and more expensive to operate and maintain. So we have our asset management program in place that seeks to extend the service life of our assets as long as practical. And we do this through routine inspections and regular maintenance. And that's all based on the premise of finding a small problem before it becomes a big problem. So at some point, however, it becomes prudent to take the old asset out and put a new one in. We cannot run the power system to failure. It is unsafe and it's not the least cost for our customers to be running the power system to failure. So after plant

replacement, the next big driver of capital expenditure is the customer sales growth. This expenditure is relatively straightforward to understand. Each year we connect new customers to the grid. That requires investments in the distribution system, in the poles and wires and equipment required to provide service to customers. Based on our current forecast of economic growth, customer sales growth will require just over 20 percent of all capital expenditure or about 11 million dollars annually for the next five years.
The plan delivers stable capital expenditures over the next five years. It provides for customer growth and ensures our power system continues to be safe and reliable. We have, however, identified three significant risks with this plan. First, customer and energy sales growth is a significant risk. Should economic factors change such as customer or energy growth varies from the forecast, then the capital expenditures will change accordingly. Second, we have a customer service system, a large, complicated computer system. It's 13 years

old. It cost over ten million dollars to build this system and replacement could be as high as 15 million. Although we don't forecast that in this to replace this system in the next five years, you know, the technology is changing and vendor support may require us to revisit that plan. And Mr. Peter Collins is here, our Manager of Information Systems, he will be before the Board later to explain some of the items in this area. Third, capital expenditures can be impacted by extreme weather events. In 1984 and again in 1994, the company was severely hit by sleet storms. Fortunately, we haven't had a repeat in 2004. In 2003, Hurricane Juan caused enormous damage in Nova Scotia. So it's impossible for us to forecast these extreme weather events. That concludes the 2005 capital plan.
MR. ALTEEN:
Q. Okay, Mr. Delaney, would you now take us through the proposed 2005 capital budget, please.
A. Mr. Chairman, this is a high level summary of the 2005 capital budget. This summary is

found in Volume 1, Schedule A of the Application. The total budget is $48,141,000 and it's broken down into several categories. These categories reflect the electrical system. They reflect the way we manage and engineer our assets in Newfoundland Power. For example, the energy supply category includes the capital expenditures required for our generation assets such as our hydro plants and our thermal plants. And since Newfoundland Power is primarily a distribution company, it's not surprising to see that the majority of our capital investment is on the distribution system at $28,635,000. I will describe to the Board, projects in each of these categories with the exception of information systems, which our Manager of Information Services, Peter Collins, will speak to.
The first category is the energy supply category and here is the list of the projects pertaining to the company's hydro electric and thermal power plants. In 2005, we proposed to spend $3,361,000 in the energy supply category. This list is also found in Volume

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MR. DELANEY:

1, Schedule B, page 1 of the Application. There are three major projects in the category; the hydro plant facility rehabilitation project at $1,887,000; the Wesleyville gas turbine overhaul at $1,124,000; and the Rattling Brook hydro plant refurbishment at $350,000. I'll now go through each project individually.

(10:30 a.m.)

The hydro plant facility rehabilitation project consists of a number of items, the largest of which is a refurbishment of Fenelons Pond dam which is shown here on the screen. This dam is part of our Seal Cove hydro system on the Avalon Peninsula and was originally built in 1946. The estimated cost to refurbish this dam is $390,000. Newfoundland Power operates 23 hydro plants. The average age of our plants is 59 years and they provide a low cost and reliable electrical energy. An item such as the Fenelons Pond refurbishment will be identified and priorized through our dam safety inspection program. We operate approximately

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150 dams and we adhere to the Canadian Dam Association guidelines to manage and engineer these assets. These are rigorous guidelines and they are the predominant standard in use across the country. So if I take you to the slide here, this is an earth filled dam. This would be the upward face here holding back the water on Fenelons Pond. And this here is the spillway of the dam. Now when you look at this dam, if it were in good shape, you would see large boulders on the upstream face and along the crest of the dam. What we have here is just a large amount of erosion that's happened over time. Like this coffer, this wooden wall through the dam here should not be exposed. So you got all your what they call riffraff, it's a large--large boulders have all eroded or, you know, over the years have through wave action, etcetera, have become displaced and fell back into the pond. So we need to get, you know, all this riffraff put back on and fill done in the dam. Another part here, you see significant erosion here where the water has worn away the material of the dam and moved it back into the pond. And

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this spillway structure is in advanced stated of deterioration. It's a wooden structure. This would be replaced with a concrete structure. This here as well has got to be designed to let the flood waters through whenever you get, sort of a flood condition on this pond and it has to be designed specifically to get the flood water through, otherwise it will over top the dam, the flood could over top the dam and that would lead to complete failure of the dam whenever you over top. Dams are not designed to be over topped. So that's a concern with this particular structure too, that this spillway is designed to get the right amount of water through under flood conditions. There's a competitive market in Newfoundland for this type of heavy, civil construction work and we'll get this work done through least cost competitive tendering.

The second project in the energy supply category is the Wesleyville gas turbine overhaul. It is estimated at $1,124,000. The gas turbine was recently relocated from the Burin Peninsula where it was under utilized to

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Wesleyville and New-Wes-Valley is the community, to improve the reliability in the Bonavista north area. It has already demonstrated its worth. On April 25th and April 26th, earlier this year, we lost a transmission line serving the Bonavista north area due to a sleet storm. And while that line was down, the gas turbine was able to provide power to the community for 21 hours. This project is needed to ensure the gas turbine remains safe and reliable. I'll take you to the slide. This is the outside of the gas turbine facility. This is the entire facility. Here we have the fuel tanks, the large building which houses the generator, the turbine and the controls. And here we have the exhaust stacks of the gas turbine. So we're moving--this is the outside of the facility. We're moving in the outside of the facility into the inside here, and this is the gas generator itself. And this is what this project is all about, it's refurbishing this gas generator. This generator is actually the same type of generator that's used in a jet airplane, same type of jet--it's a jet engine.

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MR. DELANEY:
To give you some perspective on this thing, it--when we push the start button on a gas generator, it goes from a stationary position up to 4,800 revolutions per minute. It goes from room temperature up to 1,100 degrees fahrenheit in ten minutes. So it's a machine that has to be very precise. Looking inside this machine we have a--Rolls-Royce, who are the manufacturers came and did a boroscope analysis inside this machine. A boroscope is a camera on the end of a fibre optic snake that you can kind of get into the machine and have a look around inside. And inside this machine they found corrosion on the blades and to a trained eye, there's also impact damage. Something got into this gas turbine through the air intake, some small pebble or something like that and caused impact damage. The equipment manufacturers tell us we should refurbish this unit. The corrosion is--when you think of the tolerances that a machine that goes from zero to 4,800 RPM in ten minutes has to meet, those tolerances, we think it's prudent to refurbish this unit.

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So, our plan next year is to unbolt this gas generator and ship it off to a refurbishment facility where it will be overhauled. But at the same time we're going to--there's a market in jet engines and we will go to the market and see if we get something off the shelf and compare that versus the refurbishment, to make sure this is all done at least cost.

The next project, Mr. Chairman, in the energy supply category is the Rattling Brook hydro plan refurbishment at $350,000. Rattling Brook plant is located in the town of Norris Arm in central Newfoundland. This plant was built in 1958. It is our biggest hydro electric plant. It has a nominal capacity of 12.75 megawatts and its normal production is 69.4 gigawatt hours per year. So just to put that in perspective, let's say at five cents a kilowatt hour, this plant produces three and a half million dollars in power every year. This project is being driven by the need to refurbish the 46 year old penstock, need to replace, sorry, the 46 year old wooden penstock. And this is going to be a big and complicated project. Our

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current estimate for the entire project is 11.4 million dollars. We plan in next year in 2005 to spend $350,000 on engineering with the actual construction being done in 2006 and 2007. Like I said, this project is being driven by the need to replace almost two kilometers of wood state penstock. We've replaced a lot of penstock over the years but two kilometers would represent the biggest job we've undertaken. This 46 year old wood state penstock is deteriorated and it must be replaced in the near term. The penstock, just to take you through the pictures here, is 2. 1 to 2.3 meters in diameter. And you can see the water just coming out of the penstock here. It's in an advanced state of deterioration. If you look at the penstock here and the water is spraying out of the side going down to the surge tank.

There's a tremendous amount of energy in a pipe, 2.1 to 2.3 meters thick delivering 14 megawatts of power. So this is at the end of its useful life, we wanted to get it out of the system, we wanted to replace it. While we're doing that, we want to take a look at

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the whole plant. We've got the surge tank, this is 312 feet high. This picture is actually spread out a bit so that we can get the surge tank into the picture. There's some rehabilitation work got to be done on this surge tank and if we can get it now, it will avoid a big cost down the road, so we can get it as part of this overall project. And when we go into the plant, it was built in 1958, there's a lot of old electronics, some old mechanical equipment. And while we have this plant down it will give us a window of opportunity to get some of this old stuff done. This is the synchronizer that's required to synchronize the system, the plant to the system to bring it back on. And it's got the vacuum tube still in it so it's something that's obsolete. The surge tank, just to give you an example, that's basically the pressure relief device of this plant. If this plant shuts down there has to be some way to release the pressure so the pressure actually shoots up through the penstock-- through the surge tank. To ensure the project, the full 11.4 million dollar project

MR. DELANEY:

proceeds in an orderly and planned manner, in 2005 we want to focus on engineering. Before one tender is let or any of the materials purchased, I want to make sure that we've vetted this project and all the i's are dotted and all the t's are crossed. Just to give the Board some insight into the need to spend the considerable time on the detailed engineering, I'll just highlight one item that's got to be engineered in 2005 and there are many, many complications in this project. Our current plan envisions replacing the penstock in two sections. Now we're planning that way to limit the construction window so we can avoid spillage of water. We can dam up the water so we don't need to lose any water by narrowing down the construction schedule. So we'll do it in two sections, that's the plan. But there's risks associated with that that have to be evaluated. When you do the penstock in two parts you have to find a way to keep water in the top part of the penstock when you do the bottom part because if you let the water out, if there's no water inside the penstock,

it will collapse and I certainly don't want that on my hands, a collapsed penstock. So there are ways to do it. You can design a bulkhead, certain transition joints. There are things that can be done to do this in two parts and spread the capital out over time. So we'll have to evaluate those costs and those risks associated with doing it in two stages versus one stage. So there is a need-- I need the detailed engineering to ensure this project is delivered at the least cost. That's our focus for next year.

This is our 2005 capital budget for substations. This list of projects--this is moving down through the list now. I'm out of energy supply into substations. This is our 2005 capital budget as shown in Schedule B, page two of the application. Now a substation contains all the high voltage equipment such as transformers and breakers and voltage regulators. And this equipment is used to control the transmission and distribution of power. We managed 137 substations across the province. In 2005 we propose to spend $3,337,000 in the substations category. This

expenditure is broken down into six projects as shown on the screen. Now I'm going to describe in detail the two largest projects; the replacement and standby substation equipment project at $1,052,000 and the distribution system feeder remote control project at $1,114,000.

This slide shows several of the major equipment items that can be found in our substations. Here we have the--pointing at the slide--the substation transformer. Most substations are built around the substation transformer. It's the device that's converting the voltage that comes in on a transmission line to the voltage that goes out on the distribution line. Substations contain battery banks. Battery banks are actually vital to the power system operation because when you think of it, when the power goes out, everything runs on batteries. So batteries are vital to the operation of the power system when the power goes out.

Potential transformers, these are the devices that sense the voltages on the line and send the signals to a control system,

which operate circuit breakers. So this then is basically picking up what the voltage is on the line, sending a representative sample of that voltage at low voltage, which in turn goes into the control system and we're able to detect where there's problems on the line through a potential transformer and send that over and open and close the circuit breaker, and a circuit breaker is the same as a circuit breaker in your house. It opens and closes the line.

In total, we manage about 1500 pieces of major substation equipment. A substation transformer installed will cost between one and two million dollars. A substation circuit breaker installed will cost 125 to $250,000. These are expensive items. In managing substation assets, our goal is to extend the service life of the equipment as long as practical. That involves a sophisticated maintenance strategy and you can't understand this capital expenditure unless you understand the maintenance strategy behind it. And a maintenance strategy is simple. Is based on the fact that most of this substation

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MR. DELANEY:
equipment is oil filled.

So at regular intervals what we do is we take samples of the oil, and this is a relatively new development for us based on new industry practices and new chemical analysis techniques. At regular intervals, we take samples of the oil from the equipment and have it analyzed for its chemical content at a laboratory that specializes in this type of analysis. That oil sample will establish the baseline or the fingerprint of the device. So what we do is, at regular intervals, we'll sample the oil in this equipment, and if there's no change in the chemical content of the oil, well there's no need to haul this equipment apart and do maintenance. It prevents unnecessary work. But if we see a change in the chemical content of the oil, if there's more copper or there's more paper or, you know, some change in that chemical content, then we know there's something going on inside the machine and that will trigger a maintenance overhaul of the equipment to identify the source of the problem.

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Through this approach, we're better able to manage all these big equipment items, avoid unnecessary work and we're reducing our capital cost because we're preventing premature failures of equipment. There's a good example. In 2002, we lost a substation transformer in Burin. It failed and caused a nine-hour outage. The direct cost to fix the transformer was $170,000. But that failure led to a chain of events as the systems interconnect, as is like to do, first it deferred the relocation of the gas turbine from Salt Pond to Wesleyville, because we had a nine-hour outage, we had customer concerns. So we decided that we would not relocate the gas turbine from Salt Pond to Wesleyville, and that caused an increase in cost. And then we bought a supplemental before the Board to install a new transformer in that area to provide backup for the unit that had failed.

In contrast, the exact same thing happened in Deer Lake a year after. We had the same problem, a tap changer problem in the transformer. But this time, we picked it up during an oil sample. We picked up the oil

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sample, there's something wrong with this unit. It was, you know, there was some change in the chemical content. So we knew that. We were able to get our portable transformer over to Deer Lake, take that transformer out of service and do the work before the transformer failed. That whole thing cost us about $30,000 and about a 15-minute outage for customers. So it points to the value of a maintenance strategy in terms of minimizing these capital expenditures, and I'm certain with this Replacement of Standby Substation Equipment Project, we're minimizing our capital expenditures.

Mr. Chairman, this is our system control centre where we monitor and control much of the power system. Another of the big projects in the substations category I alluded to before is the Distribution Feeder Remote Control Project at one million--I think it was $1,052,000. No, $1,114,000. We started that project in 2002 and we plan to continue in 2005 and for the duration of the capital plan. We have 300 feeders in our system. Each has a device that monitors and controls the feeder.

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The device is either a relay or reclosures. This project involves the replacement of these reclosures and relays with newer, more technically advanced units, and the project is timely, due to the age of the existing equipment. By the end of 2005, we will be able to monitor and control 115 of our 300 feeders from our System Control Centre, and what we're doing in the field is we're replacing the relays and reclosures for each of these feeders and bringing all the intelligence back to the System Control Centre.

With the remote monitoring and control of feeders, our operators now at the System Control Centre can quickly pinpoint a trouble spot and direct the field crews accordingly. There's instances when the operators can just restore power from the System Control Centre and not dispatch any field staff. This has reduced our outage durations. It has reduced a lot of us out there stumbling around, you know, out there trying to find the problems, because there's no intelligence on these systems that don't have the remote control, and it's reduced our cost. It's reduced outage

MR. DELANEY:
durations, reduced costs. Just by comparison, on the feeders that we don't have this remote control technology, we got to wait until the customer calls in before we know there's an outage. So when the customer calls in, is that one customer? Is it localized or is it widespread? We don't know until more customers call in or we dispatch the crews to go out and look. So overall this has improved our operations tremendously, this program.

This is our transmission category, working down through the list of the Capital Budget, and it can be found in Schedule B, page three. Transmission lines run from substation to substation. They operate at very high voltages. In our case, we have 138,000 volt lines and 66,000 volt lines. They're often remotely located, accessible by snowmobile or ATV. We operate 110 transmission lines and it has an overall length of over 2,000 kilometres. 30 percent of our transmission is more than 40 years old. We manage the transmission lines by visually inspecting every line every year and every

five years, we conduct a climbing inspection, a detailed climbing inspection. The problems and deficiencies that we find through that course of inspection drive the transmission capital budget.

In 2005, we propose to spend $2,597, 000 on rebuilding and refurbishing transmission lines, and no new transmission lines are planned. There are three big items in this transmission line category and the cost in total, $1,550,000. And then there's a large number of small items totalling $1,047,000 and these small items are small repairs on about 50 lines. But I'll go into the three big items in detail.

(10:49 a.m.)

First, we plan to rebuild an eight-kilometre section of transmission line 43L that runs between the communities of Heart's Content and New Chelsea. This line is 48 years old. We've extended the service line as long as it is prudent and we're concerned about the overall condition of this line that carries 66,000 volts.

The second line we plan to rebuild is a

five-kilometre section of transmission line 11L that runs from our Tors Cove hydro plant into our Mobile substation. This line was built during World War II and is now 62 years old and deteriorated to the point that replacement is necessary.

And finally, we plan to rebuild a five-kilometre section of transmission line 124L that runs between Clarenville and Gambo. This line is 40 years old. The problem with the 124L line is one of clearance. This line operates at 138,000 volts. On this line, we don't have enough clearance between the line and the ground, particularly in winter when you get ice building up on the line and at the same time you have a large amount of snow cover. We got a lot of snowmobilers that travel this particular transmission line corridor, as they do all of our transmission line corridors. So the adequacy of this ground clearance is a great concern for public safety.

Mr. Chairman, this is the 2005 Capital Budget for distribution, which is found in Schedule B on page four. Newfoundland Power

is primarily a distribution company. It's our largest category of expenditure. We operate over 8,000 kilometres of distribution lines to serve 222,000 customers. The proposed capital expenditures in distribution category amount of $28,635,000 or 59 percent of this total budget.

I'm going to approach my presentation of distribution in two parts. First, just to take you through, I'm going to explain the portion of the distribution budget that's primarily driven by customer growth. In that area, we have extensions, meters, services, streetlights, transformers and down here, feeder additions and upgrades to accommodate growth. These are the category the projects are primarily driven by growth.

Second, I'm going to explain how we manage the existing network, the existing 8,000 kilometres of line out there, and to do that, I'm going to explain the reconstruction project, the rebuild distribution lines and the distribution reliability initiative. This is the way I kind of think of distribution, customer growth and then maintaining and

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MR. DELANEY:
running existing system as we have.

Just for completeness, I'll explain the remaining items on this list. We have the Aliant pole purchase. That covers the 2005 instalment associated with the Support Structures Agreement that we entered into with Aliant and that was brought before the Board and approved by the Board in 2001 and the final instalment will be made in 2005.

We have a project here Relocate-Replace Distribution Lines for Third Parties. It's somewhat self-explanatory. Throughout the year, we'll get requests from municipalities, provincial government, federal government, Aliant, cable TV, property developers, various requests to relocate a line and customers pay for a portion of the relocation of that line. And we have interest during construction which is the interest that will be charged to work in progress in distribution throughout the year.

Let's look first at the customer growth components of distribution. About 40 percent of the distribution category or $11.4 million

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in capital expenditure is needed to connect new homes and businesses to the power grid. A new customer will require new poles, new conductors, new wires. We have to install distribution transformers. We run service wires from the utility pole to the premises and we install a meter. Typically for every three or four customers connected to the system, there's a new street light involved. This is an area where we contract out the majority of the line work in a competitive tendering process. The work involved with construction of distribution lines is relatively simple construction work and is highly standardized. So over the years, we've reached these costs, in terms of extending service to new customers, by developing our contractors and working with our contractors, and we have a highly competitive market in Newfoundland for line construction work, which we avail of.

To develop the estimates for capital required for customer growth, we develop a customer growth forecast, based on economic modelling, and we consider the historical

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expenditures to determine per unit costs of connecting new customers. In recent years, growth has been more robust than forecast, and that's put some upward pressure on the capital expenditure required for customer growth. In 2005, we are forecasting 2,461 new customers will attach to the system, and that compares to 2,832 we expect to connect in 2004.

Another part of managing growth is to step back and look at the overall distribution network with engineering modelling and analysis and determine whether we have to install new feeders to increase capacity, whether we have parts of the system that are overloaded due to the general growth in an area, in a particular geographical area. And this budget contains 319,000 for a new feeder out of the Virginia Waters substation on the east end of St. John's, and this is needed because we have seen a large amount of growth in the Stavanger and the Clovelly areas and we did a planning study, which is filed with this application, which shows that the least cost way to handle some of the overload conditions that we have in that area is to build this new

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feeder.

So here are the three main projects that show our strategy for capital expenditure related to the existing 8,000-kilometre distribution network. I'll go through each one of these individually. The first two, the Distribution Reliability Initiative and Rebuild Distribution Lines, are proactive approaches to managing the network and reconstruction, by its nature, is reactive.

The Distribution Reliability Initiative Project is estimated at $872,000, and in 2005, we plan to rebuild a feeder that runs from New-Wes-Valley to Lumsden. We started this work in 2004. It was a two-year project, so we're planning to do the rest of the reliability rebuild on this feeder in 2005, and we're planning to start on the rebuild of the Gander Bay to Carmanville feeder in this area.

We have 300 distribution feeders. We did a detailed analysis of the worst feeders in the systems in terms of reliability performance. We ranked our feeders and its filed with this application. We've ranked the

MR. DELANEY:
feeders by SAIDI and SAIFI statistics. Now the SAIDI, these are the statistics that are used Canada wide. The SAIDI is the measure of the number of hours that a customer is without power. And the SAIFI is simply the number of outages that a customer experiences.

So we ranked all of our feeders. Then we looked at each feeder individually to determine the root cause of the poor reliability problem. In some cases, we'd already had taken action to solve the reliability problem. In other cases, you find the reliability problem may be related to trees. So there's nothing you're going to do in capital to address a reliability problem related to trees. It's about tree trimming. So it's not only a capital exercise. It's an exercise in managing the whole company. But as you work down through the list of the worst feeders by reliability, you're going to find these feeders that exhibit poor reliability performance because the overall line--because of the overall condition of the line, overall deterioration of the line, factors such as the

line is simply not strong enough to withstand the environmental conditions in which it must operate, in terms of the high wind and ice and stuff, and you'll find lines that have deteriorated that are away from the road, sort of these characteristics. And these are the types of problems we found in the Wesleyville 02 and the Gander Bay 02 feeders. Over the past five years, customers on these feeders have experienced reliability three and a half times worst than the company average, and that indicates to me--I've travelled along these feeders several times. These feeders are simply worn out.

Mr. Chairman, this is the--while the distribution reliability project focuses on specific geographical areas, the rebuild distribution lines project deals with problems that are system wide and not necessarily geographically specific. These are problems that we have everywhere on the distribution system. This project is estimated at $4,210,000. And this slide slows some of the problems that are out there that we are addressing under the rebuild distribution

lines. I'll just take you through some of these now.

(11:00 a.m.)

Up here in this corner, we have cutouts, defective cutouts. You see these out on the lines. It's a mechanical switch that opens or closes a distribution transformer or branch line. A lineman would use a stick to open and close it. We're finding these are breaking out there in great frequency. You go into any safety meeting in this company between January and April and this will be top of the list of the linemen. They need to open and close these and they're falling apart as they're opening and closing them and they're ending up with the stick with the high voltage wire at the end of the stick and it's a safety concern. So part of the rebuild distribution lines project is replacing defective cutouts, and these are two that are broken in two. Industry-wide problem.

Rusting transformers. In our salt corrosive environment in Newfoundland, we have a big, big problem with rust, corrosion on transformers. We've moved to stainless steel,

ten-year warranty, a good decision that we made and we're having good success with stainless steel out there with the corrosion problem.

Sleeves, automatic sleeves, these are basically connections connecting two pieces of wire together. Back in the early 90s, there was a major productivity gain with automatic sleeves. Easy way to hook wire together. They've proven throughout the industry to not be that great. They're rusting. So this is a problem we're dealing with, as are all utilities, with automatic sleeves deteriorating out there.

And in St. John's particularly, padmount transformer, similar to this problem with old transformers, we have corrosion and these transformers reaching the end of their lives. There are numerous problems when you put a padmount transformer on a person's property, in terms of backfilling and landscaping and other things. But these have all reached the end of their lives, so there's a fair amount of corrosion on them as well. So that's part of what we're addressing. There are other

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things too, but that give you the feel for there are a number of items out there in the distribution system that need to be handled.

My chief concern with all this work is it's a big system. There's a lot of work. How do we go about it in a productive, methodical, planned fashion? To achieve this, our procedure is to inspect our distribution lines on a five-year cycle and there we'll develop our estimates and plans for the upcoming year, and the five-year cycle is relatively common throughout the industry.

So then what we do in executing the work is we have utilized what we've come to call in the company as a mobile workforce. We assemble a large number of crews, typically, you know, 12 or 15, you know, the numbers vary but that magnitude of crews. We set out a longer day, usually a ten-hour day. And we pre-assemble all the material, do all the staging and then we'll take the power off at the customers' convenience, you know, scheduled with the customer, a lot of contact back and forth with the customer, arrange

typically a three-hour outage, and we blitz the thing. We blitz the feeder with the large number of crews. We found that that approach to rebuilding distribution lines project has been highly effective and productive. And I also note, there's a project in the information systems budget for the development of a line inspections software database that's going to help us further improve our efficiency and organization of the work with respect to this project.

The last item in managing the distribution network is the reconstruction project. Reconstruction is used to fix distribution plant that has failed or is in the danger of imminent failure. In this picture here, we can see some storm damage down in Ferryland. As a result of a storm, the cribs and the poles were washed away and the poles ended up--the picture is not there, but the poles ended up falling down. So this is the type of problem that we deal with reconstruction. When you're managing a big network, there's a large number of items that will come to your attention throughout the

year, either through inspections or otherwise, that have to be dealt with immediately because they're either broken or they're in a state where a imminent failure. So far this year, for example, these are typically very small projects. There's been 160 jobs in the reconstruction projects so far this year and the average cost of those jobs is $8600, and we estimate our--we do our estimate for future years cost based on history.

This is the general property budget. It's found in Schedule B, page five. It's $1,016,000 and just over two percent of the total budget. Newfoundland Power has 36 offices, service buildings and district buildings. We manage 25,000 metres of space and we plan to spend $325,000 or less than one percent of our capital on property. We propose to spend $691,000 on tools and equipment. Operating a power system requires many tools, such as the hot line tools used to perform this complex job here. In this job, the linemen have used these hot line sticks to hold off the energized conductor. So this is 138,000 volts running here. So they're doing

this job, keeping the power on, and doing this job on this line. So of course, this hot line gear has to have a very high standard and if it fails any of its tests, we replace it. So customers are not seeing an outage in this particular--for this particular job.

Mr. Chairman, in 2005, we propose to spend $2,642,000 in the transportation category, as seen here in Schedule B, page six. We operate a fleet of some 400 vehicles, which include 80 heavy-duty vehicles, 195 passenger vehicles, and 125 off-road vehicles. We are essentially a mobile company. Many of our employees, such as our line personnel, technicians, meter readers, are mobile for the majority of the day and their workplace is on the road, in their vehicles. We will not be increasing the size of the fleet. We need to replace seven heavy-duty vehicles, 46 passenger vehicles and eight small all-terrain vehicles, such as snowmobiles. For our heavy fleet vehicles, our replacement guideline is ten years or 250,000 kilometres. For passenger vehicles, the replacement guideline is five years or 150,000 kilometres. And this

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guideline initiates a review of the vehicle maintenance costs, the operating history and the overall condition of the vehicle before a final decision is made to replace the vehicle.

When you compare our 2005 capital budget for transportation with history, it's about ten percent higher than the average of the past five years, and this is driven by two main factors. First, there's been a consolidation amongst the heavy-line truck manufacturers. There are a number of the lower end competitors have dropped out of the business and we're seeing a general price increase from the manufacturers that now dominate the market. Second, in the early 80s and--excuse me, in the late 80s, early 90s, we moved into hot line work. Now that is working, as I showed in that picture, working on the lines, on the power lines while the lines were energized at high voltage. The picture I showed you was transmission, but we also did it on distribution. This change in work required a new type of truck, and so we saw a large number of trucks come in in the

early 90s. So these trucks now are ten plus years old and we're seeing a bubble in replacement of heavy-duty trucks that we expect to level off in the next few years.

Least cost transportation management requires that we consider our fuel and maintenance costs, those operating costs, in conjunction with the capital expenditure, and prudent capital expenditure has been the main reason why we have been able to control our transportation operating costs.

The telecommunications category is $60,000, as shown in Schedule B, page seven. We do not have a telecommunications department. It's not core to our business. Our VHF radio system is in good working condition. We expect it to last to at least 2011. There's a relatively small expenditure required to replace about 20 of the 340 VHF mobile radios that we have in operation.

General expenses capital is $2,800,000. This is the amount of Newfoundland Power's administrative expenses that are charged to capital and this is calculated in accordance with Board orders.

The unforeseen allowance is $750,000 and shown in Schedule B, page nine. This allowance is used for emergencies, to cover any unforeseen capital expenditures which have not been budgeted elsewhere, and the purpose of the allowance is to permit the company to act quickly to deal with an unforeseen event in advance of seeking the specific approval of the Board.

And that concludes the capital budget for 2005.

MR. ALTEEN:

Q. Okay then, Mr. Delaney, would you now comment on the variances with respect to the current 2004 Capital Budget for the Board?

A. Mr. Chairman, this big table here is the 2004 Capital Expenditure status report from Volume 1 of the pre-filed application. In column one, we have the capital expenditure category. That's the energy supply, substations, transmission, et cetera. Column two is the budget, as approved by the Board. The third column shows the forecast 2004 expenditures as of June 30th.

Column four shows the forecast deferrals.

Now these deferrals result from our decision to manage the overall capital expenditure in 2004 to more closely match the overall budget as approved by the Board. The main driver of the increased expenditure was customer growth, and we've exercised engineering judgment in selecting these deferrals. However, there are reliability and costs risks in deferring any project. The fifth column shows the total forecasted expenditure, including deferrals, and column six shows the variance between the budget, as approved by the Board, and our forecasted expenditure.

As of June 30th, we were forecasting a total of 3.2 million or approximately six percent above budget, which is consistent with the past five years. Variances from budget are unavoidable due to many circumstances. For example, the customer growth may turn out to be greater or less than forecasted during the budget process. Second, much of our work is refurbishment and as we get into the work, there are discoveries and change conditions that were not originally anticipated and included in the original cost estimate. And

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third, there's a time difference between the preparation of the estimate and the actual construction, and sometimes more than a year, and in that interval, market prices change for equipment, materials and contract labour.

Detailed explanations of the individual variances are pre-filed in Appendix A of the 2004 Capital Expenditure Status Report, and I'd like to explain the larger variances.

The energy supply category has a forecast variance of approximately $680,000. This is primarily due to increases in material and engineering costs associated with the New Chelsea hydro plant refurbishment project. For example, the price of steel is up significantly from when the estimate was prepared.

The distribution category has a forecast variance of approximately 2.5 million. This is primarily because customer growth has exceeded our expectations, particularly in the Northeast Avalon.

One other significant variation is the variation associated with the 2002 project

Wesleyville Gas Turbine Relocation. This project was approved in 2002 to relocate an under-utilized gas turbine from Burin to Wesleyville to improve reliability in the Bonavista North area. This energy supply project came in significantly over budget, and the main cause of the variances can be summarized in two parts. First, the system problems on the Burin in early 2002, due to those system problems, we decided to postpone the project for one year, due to customer concerns. We subsequently filed a supplemental budget with the Board for capital expenditure on the Burin to deal with the problem there, and when that project was finished, we moved the gas turbine. This delay caused approximately $520,000 in additional direct costs, plus the associated engineering, project management and supervision costs.

Second, this was a very complex and complicated project. We found during the course of the work that a number of the components of the gas turbine, that we had originally intended to reuse, were found to be

unusable or needed significant refurbishment. This resulted in $580,000 in additional direct costs, plus the associated engineering.

As I mentioned earlier, the gas turbine is in service and has already demonstrated its worth, having kept the lights on for 21 hours down in Wesleyville during a sleet storm on April 25th-26th. When we revisit the original plan where we compared the relocation of the gas turbine to building a second transmission line, to installing a new generation in Wesleyville, when we go back and revisit that plan and we put in the installed cost of the gas turbine, the actual costs, we find that it's still the least cost plan for improving reliability in Bonavista North, to the tune of $1.9 million in net present value. So relocating the gas turbine, with the actual costing, is still the least cost thing to do down in that area to improve the reliability.

Q. Now Mr. Delaney, do you have any concluding remarks with regard to the 2005 Capital Budget application?

A. This is a prudent budget that addresses needs in many areas, including the customer service,

reliability and safety. Many of the projects in this budget rely on engineering judgment and I lead an engineering team at Newfoundland Power and we have fulfilled that professional obligation. We operate Newfoundland Power as a business. We manage a large network in a planned and organized way. We have good inspection programs, good maintenance programs, all based on industry best practices, and we seek to maximize the service life of our assets. This is a proactive budget and although failures are inevitable, we can't be reactive and be least cost a the same time. This budget meets the goal of reasonable service at least cost, and the company seeks the Board's approval for this $48,141,000 capital budget for 2005. Thank you, Mr. Chairman.

Q. We're right about on time, Mr. Chairman.

CHAIRMAN:

Q. Good timing, Mr. Alteen. Thank you.

MR. ALTEEN:

Q. Thank you.

CHAIRMAN:

Q. We'll break for 15 minutes.

(BREAK - 11:15 A.M.)
(11:36 a.m.)
CHAIRMAN:
Q. Mr. Alteen, are you finished with Mr. Delaney for now?
MR. ALTEEN:
Q. He's available for cross-examination, Mr. Chairman.
CHAIRMAN:
Q. Thank you. Mr. Kennedy, are you ready to proceed?
MR. KENNEDY:
Q. I am, Chair, thank you.
CHAIRMAN:
Q. I understand you'll be taking us to lunch? I mean, up to the time of lunch?
MR. KENNEDY:
Q. Yes.
CHAIRMAN:
Q. There's a difference.
MR. KENNEDY:
Q. Yes, there is. I suspect so. This is one of those it's only going to take me a few minutes to ask the questions, so subject to the witness' responses, but I would suggest that

it will be about an hour in total. Mr. Delaney, I'd like to start off by dealing with the growth driven projects in the distribution section of your capital budget. And a good place to start, Chair, would be to just do a review of some of the RFIs that were submitted in answer by Newfoundland Power and specifically PUB-27. And PUB-27 is a number of parts. And I'd just like to bring the Panel quickly through those parts first with the witness and then as a follow-up, I've done a spreadsheet which I plan to hand out and ask the witness some questions about. And I've provided that spreadsheet to counsel for Newfoundland Power but only yesterday which I note under Rules to Procedure is technically not 24 hours, it was a 24 hour time frame on new documentation. But I don't intend to put it forward as an exhibit, per se, it's just an illustrative aid for the Panel.
MR. ALTEEN:
Q. We're thankful for the heads up we got, Mr. Chairman. We're on an abbreviated time schedule.
CHAIRMAN:

Q. Thank you.
MR. KENNEDY:
Q. So this document that's before you, Mr. Delaney, is the PUB-27 point one. And this question asked Newfoundland Power to, in relation to the projects that were listed, provide the aggregate of all costs contained in the projects that are directly attributable to the growth in customers experienced by Newfoundland Power. I note that in reply by Newfoundland Power you say that the majority of the growth is attributable in new customers, however, a component of the total load growth is also attributable to existing customers who increase their energy usage. And is it I understand correctly that Newfoundland Power doesn't break out projects related to growth in new customers from projects related to growth in energy sales per se, that they're not tracked separately? If you read the last line in that reply?
A. Yes, that's correct.
Q. Okay. The references in the question to the project numbers B-31 and the like are as provided in your table below, extensions,

meters, services, street lights, distribution transformers, reconstruction, rebuild distribution lines, distribution reliability initiative and additions to accommodate growth. And this I think dovetails with a chart that you had up in your power point presentation. And could you confirm that, first of all, that I have, in listing those projects, managed to capture all the projects in the distribution section that would have growth as a component of it?
A. Yes, yes, I think you have, yeah.
Q. Okay. I think that dovetails with what you indicated when you were going through your power point presentation. And again, just to make sure that I've got a firm understanding, in the case of project, for instance, B 31 extensions where you have a budget of $6,374,000 for your 2005 capital plan, you indicate that 100 percent of that project category is attributable to growth, so that would be attributable to growth in customers and attributable to growth in energy sales, correct?
A. On the distribution system, yes.

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MR. KENNEDY:
Q. Right. Extensions on, these are all distribution related projects?
A. Yes.
Q. Okay. And so B 31, extension on your distribution related--distribution related projects, budgeted for 6 million, 374, 100 percent of that is related to the growth in new customers or energy sale?
A. Yes, that's correct.
Q. Okay. If we go to B 27.2. And, Mr. Delaney, this RFI asked the same question in effect, or at least dealing with the same projects for distribution, extensions, meters, services and so on. It asked Newfoundland Power to provide the unit cost per new customer for each of those budget categories. And again, this is, includes the unit cost per new customer for both growth related to, the number of new customers in growth related to increased energy sales, correct?
A. Yeah -
Q. That unit cost per new customer, for instance, for extensions of $2,590 per customer would include the expenditures related to growth in

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extensions that's attributable both to the increase in customers and an increase in energy sales?
A. That's correct.
Q. Okay. And so what we have, if I'm reading this correctly, is that the unit costs per new customer for 2005 is budgeted at a total of $4619 per new customer?
A. Yes, that's correct.
Q. Okay. Now, Panel members, just so you have the reference, I think it might be handy to just go to 27.3 at the documents. And 27.3 asks for the same information for those same budget categories only now for the fiscal years 2000 through to 2003. And there's attachments, there's five pages to that RFI, just so you see where it's from. If we could go to 27.5 These are the--this question asks for the growth and net growth in new customers as well as--or just new customers for each of those fiscal years, so that you see that information is there. And then 27.8, please? 27.8 provided the growth in energy sales for each of those years. And I think that that's all the RFIs that we need to look at. And now

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what I'd like to do, and I believe the witness already has a copy of this or does he?
CHAIRMAN:
Q. You might give him one just to make sure he's talking from the same piece of paper you have.
MR. KENNEDY:
Q. Okay. Chair, this is the spreadsheet that I did up and I'll explain it once it's handed out. Yeah, we can put it in as Information No. 1. Now, members to the Panel, by way of explanation, what I've done is taken the information that was in the RFIs that we just went through and just put them down into a different format and basically included all the information in one spreadsheet. And so it should--each piece of information in here should tie directly to an RFI except for where you'll see unit costs over budget by, and actual annual growth and unit costs. They're my own calculations based on the figures that Newfoundland Power provided in the responses to the RFI. And so, just taking the year 2001, because that's the full--first complete year. You'll see that I have a percent attributable to growth, that's as per the RFI

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that Newfoundland Power would have responded to showing, in the case of extensions, 100 percent of the budget item is attributable to growth, 20 percent for meters, 70 percent for services and so forth. They had a budget of $4,005,000 in 2001 for extensions. And a budgeted unit cost in 2001 of $1693 per customer. Their actual expenditures under extensions for 2001 would have been 5,404,000. Their unit cost actually for extensions was $2343. And then I've calculated in the case of 2001 for unit costs, the unit costs went over budget in that year by 28 percent for extensions. And the actual annual growth in unit costs, that would have been from year 2000 to year 2001, were 38 percent for extensions. The bold numbers that you see right next to those two columns, 23 percent and 27 percent are the total. So in other words, when taking into account all categories, extensions, meters, services, street lights, transformers and additions, the unit costs went over budget by 23 percent in the year 2001 and the actual annual growth in unit sales from 2001 as compared to 2000 would

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have been 27 percent.
(11:48 a.m.)
CHAIRMAN:
Q. You mentioned a number of 28 percent, Mr. Kennedy. Where did you come up with that?
MR. KENNEDY:
Q. Thirty-eight percent I think I -
CHAIRMAN:
Q. Okay.
MR. KENNEDY:
Q. If I said 28, it was an error, Chair. The 38 percent is just I was referring to the unit costs over budget in extensions in 2001, you'll see a 38 percent figure there.
CHAIRMAN:
Q. Yes, I do.
MR. KENNEDY:
Q. So, Mr. Delaney, having a fairly brief, I appreciate, opportunity to look at this information presented in this format, I wonder if you can provide the Panel with an explanation, if you would, for some of the trends that we see or seem to be apparent in this document between the budgeting of unit costs and then the actual annual growth in

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unit costs year over year for the period 2000 to 2005? So, for instance, in 2000 your unit costs were over budget, came in over budget by 45 percent. The amount that it cost you to hook up a new customer was 45 percent greater than you budgeted in 2000. That's repeated again in 2001 by 23 percent, your unit costs went over budget by 23 percent. 2000 your unit costs went over budget by 16 percent. And then your unit costs went over budget by 2 percent in 2003. Your budgeting growth in the unit costs in 2004 as compared to 2003 of an extra 19 percent, and your budget to budget growth form 2005 compared to 2004 is two percent as an overall. Could you explain what's taking place here, why the unit costs to hook up a new customer would increase a total of 52 percent in that five year--sorry, 39 percent in that five year period as is reflected by that last number down in the column?
A. Yes. There are a number of factors involved in this explanation. First of all we look at the--and I'll caution that I haven't had a chance to vet all these numbers and add them

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up and assume they're correct, but we'll go on that assumption that -
Q. I'm a lawyer, not an accountant, so I'll respect your being subject to your own verification. There may actually be an anomaly there, so.
A. If we look at the unit growth cost of 39 percent that would compare 2005 to 2000, the main factor that would drive the growth in unit cost would have occurred between the year 2000 and 2001. In 2001 we purchased all of Aliant's poles and from 2001 onward we were responsible for installing 100 percent of the poles on the island, and in turn we charged Aliant the rentals on those poles. In 2000 Aliant were installing, I don't have the exact numbers, but Aliant were installing the majority of the poles on the island in the year 2000. So when you think of the cost of extensions, a large component of the cost is the cost of installing the pole. So in 2000 we had a situation where we were installing far fewer poles than we were in subsequent years. Now, that's been balanced off with the rentals that we get from now installing posts,

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but in the year 2000 we were actually paying some rent. There was an agreement going back and forth between us and Aliant. We were paying rentals on their poles, they were paying rentals on ours. So if you look at the overall per unit cost, let's use 2001 to get Aliant out of the picture, because pole installations is a significant part of the cost of serving new customers, we'll have the actual per unit cost in 2001 at $4226, if I'm reading this correctly, as compared to 4619 in 2005, which is a change somewhere in the neighbourhood of 9 or 10 percent increase as opposed to 39. So there has been an increase in the per unit cost from 2001 to 2205 of approximately 9, 10 percent, in that order of magnitude. Now, per unit cost, when you're trying to develop a budget for how much do you have to spend to connect customers to the grid in the coming year, it's not an exact science. The best information we have is to develop a forecast of the number of new customers we expect and look at our history, look at our system and derive a per unit cost. But when you think of how the distribution's

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MR. DELANEY:

infrastructure is built out, there's this timing lag between when we build and when the customer connects. When you get into a period of high growth, what happens is we're building our infrastructure and building our infrastructure and building a lot of infrastructure quick and customers are hooking up. When the growth tapers off, the customers come in and fill in the infrastructure. So in periods of high growth our per unit cost per customer will tend to be greater than in periods of low growth when the per unit cost per customer will be less. I'll give you a good example. I was directly involved in Southlands back when we developed this methodology in the early '90s, we developed this concept, this way of trying to anticipate what the customer growth would be in the next year. We built the entire infrastructure for Southlands in one year and that just so happened in the early '90s turn down in the economy. So we put all this extension work in, put all these transformers in, the customers never showed up. But as the

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customers showed up in Southlands over the '90s and in recent years the per unit cost in that particular subdivision was very low. So, it's a good way, it's a good way of--it's the best way we've got to predict what our future expenditures will be to connect customer growth, but it's not perfect. We've attempted even to try to track subdivision lot growth and try to make the formula based on subdivision lot rather than customer, because we're building the infrastructure to the lot, not so much the customer, because of this timing difference and that never really worked because it's when you go out and talk to developers, etcetera, you'll get very optimistic estimates as to how much is going to be done next year. That being said, that's the main mover behind the extensions account is a little bit of out of sync with customer growth. But if we compare it, 2005, the per unit cost to 2001, we have a difference of somewhere around 9 or 10 percent in per unit growth, which, you know, it's about 10 percent, there's a certain element of that related to inflation, extra, you know, labour

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cost, extra material cost, but there is a component in there that's related to timing differences with respect to when we build the infrastructure and with respect to when the customer attaches.

Q. Okay. A couple of follow-up questions to that, Mr. Delaney. There's a column there about customer growth and I took them, that's the gross customer growth figures that were provided in--just so we have the specific reference. That's in 27.5, that RFI, and it was both the net domestic growth and the gross domestic growth figures provided. And I took the percent change, I guess, year over year that showed up in that table for gross domestic growth. And in turn I took the energy growth from 27.8. You wouldn't really classify the growth year over year from that period, 2000 to 2005 as the high growth era, would you? Like, would growth of 1.3 percent up to a maximum of 1.6 percent year over year be considered by Newfoundland Power to be high growth?

A. I think overall in the province, that's correct, but for the northeast Avalon we have

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seen growth in the last few years that is very high in comparison to history. The developments in the St. John's area in particular and some in the Corner Brook area with respect to Humber Valley Resort are growth rates that I would characterize as very high relative to what I've seen in my career.

Q. I'll assist you there, Mr. Delaney. There's PUB-10.2. If you could just scroll down to the chart there? The question asked for each of the years from 2000 to 2004 showing a breakdown--show a breakdown by rural and urban growth, sorry, of the number of customers added to the system. So, for instance, in 2004 forecast the eastern region you're forecasting 2265 new customers, 1643 of which come from St. John's, but in the western region you're only seeing 567 new customers. So that's what you're indicating that the growth is in pockets there, I take it, that there's high growth in some--higher growth in some regions of Newfoundland Power's distribution territory as opposed to other areas, that's what you're suggesting?

A. Yes, that's correct.

MR. KENNEDY:
(12:00 p.m.)
Q. And that that would--and so if we go back to Information No. 1, the customer growth column, although the numbers are not high in the sense of growth year over year of 1.3 percent, 1.2 percent, you're suggesting that they may mask some more volatile growth that's occurring in specific regions in the province and that goes to explain some of the reasons why your unit costs have increased as much as they have in the same period? Is that the tick tack toe, if you will, that you're -
A. I'm not really sure that because the growth is more concentrated in one area than another area that that would lead to a change in the per unit cost. I don't think that's correct.
Q. Okay. See, because, like, there's some anomalies that just sort of pop out at you. If you look at 2004, for instance, and you look at meters, you have budgeted $235,000 for the current capital budget year and the unit cost is $102 per meter, but the preceding year your actual unit cost for a meter was $39 for 162 percent growth in the cost of new meters

per customer. Now, I'll try to assist you here. Is that related to those new automatic reader meters, the ADR, I think it was called, meter?
A. Yes, the change in unit cost, actual unit cost between 2004 and 2003 is due to the installation of AMR meters in 2004 that was not there in 2003, that's the automatic meter reading, that's correct.
Q. Okay. Because otherwise your unit cost for you meters were actually always well below budget. In 2000 you came in 26 percent below budget, in 2001 you came in 29 percent below budget, 2002, 23 percent below budget, and 2003, 33 percent below budget, and 2005 you were 23 percent below budget. So the meters have generally come in lower than budgeted, correct?
A. Yes, they have.
Q. So -
A. According to this spreadsheet, yes.
Q. Right. So the meters, at least according to the spreadsheet, and again, they're just the numbers that were provided in the RFIs, the meters really aren't the driver of why your

unit costs have been increasing during that period, correct?
A. Yeah, just looking at it, see, the meters represent about somewhere between one and two percent of the cost of hooking up a new customer. So they're not a main driver in the overall per unit cost. The main drivers would be in the bigger items which would include extensions, services and transformers.
Q. Right.
A. And if I may, I'll just go into a little bit into the services--to the other items to give the Board a flavour of what are some of the components behind this per unit cost. I described extensions, how there are timing difference between the installation of a plant and the customers actually showing up, which is one of the factors behind extensions. If we look at services, there has been some increase in the per unit cost of services over the years. One of the factors behind that was we, in early--around 2002, 2201 we brought a program out in the Company mainly targeted at our line staff to do it right the first time. And you know, it was all about getting quality

control into the system to prevent future problems. So with respect to services, it's actually one area that we focused on a lot, that linemen when they went out and did a service, to do it right the first time. And that added a little bit of labour to our services account, but we expect to get the dividends down the road. Some of the things we did, we came up with a different type of air seal with the connections on the services that required longer to tape it up and stuff. So we made a deliberate effort to improve the quality of work with respect to services. Transformers, there is some per unit change in the cost of transformers. And if you remember my slide, I showed an old transformer and a new transformer. We moved to stainless steel transformers in the early, around 2000, 2001. And that increase the per unit cost of transformers from a capital sense but it will decrease our operating costs down the road. So there are some drivers there. So when I look at this whole $11,000,000, $11,368,000 that it's costing us to hook up new customers and I see a growth in that per unit cost from

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MR. DELANEY:
2001 to 2005 of somewhere around 9, 10 percent. That would be what we're dealing with in terms of, you know, the new things we've done in capital in terms of improving our services, improving our transformers with the thinking being that we'll get operating cost dividends down the road.
Q. Just so we have again a reference specifically, 27.11, 27.11. For the benefit of the Panel members. Panel members, this is an RFI that asked for a reconciliation of the costs in the capital budget as per the earlier questions in the RFI 27, one, six, nine and ten. And this is what you were referring to a moment ago, Mr. Delaney, if I'm correct, the 11,368,000. So that's the portion of the distribution budget that's related specifically to growth?
A. That's related to growth, yes.
Q. And within that number the unit cost per new customer that account for that 11 million 368, according to Info No. 1, have increased by overall 39 percent since the year 2000 to the year 2005? And again, I'll respect you to

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suggest that it's subject to your own checking of those numbers because that's my figure, but.
A. From 2000 to 2005 it's increased 39 percent. However, in 2000 we were in the situation where Aliant were installing a large portion of the poles in the Province of Newfoundland, so the equation changed quite a bit between 2000 and 2001. And I don't think a comparison between 2005 and 2000 is meaningful, but a comparison between 2005 and 2001 would be a more meaningful comparison to take into the account that Aliant are not--Aliant stopped installing poles in 2001, but in 2000 a large portion of the cost associated with connecting new customers was borne by Aliant. As well, there's another thing I might add. The project additions, feeder additions for load growth and reliability is included here. We approach the justification of that project totally differently. We don't estimate the cost of that project based on pre unit cost or customer growth. What that project is based on is justified on the basis of engineering analysis of the system. We'll look at all of

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our distribution feeders and determine whether any are overloaded. Now, that's not because of customer growth in the given years, it's because of the accumulation of customer growth up to that point. So the feeder additions for load growth is not something that we equate to that number of customers in that year, it's equated to looking at the power system, is this feeder overloaded, do the engineering analysis, do a study of alternative of what's the least cost way and determine what way to address the system overload. So it's a little different than the other projects in that regard.
Q. Okay. I just want to complete the record on this, Chair. And Mr. Delaney, I just wanted to point out to the Board the actual formula that's used by Newfoundland Power to arrive at its budgeted figure for expenditures per new customer. And this is provided in PUB-28.1. And that's the second page of 28.1, or Attachment A, sorry, that is, yeah. We'll need that as well, but the actual 28.1 should be there as well. Yeah, here we go. So, Mr. Delaney, this asks for the working

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calculations to show the historical based costs in each of the above projects. And the first one was B 31, which is the extensions project which we were just looking at. And do I gather correctly that Newfoundland Power, in putting together its budget, say, for this capital year, 2005, uses a calculation which involves an analysis of the historical expenditures that's then adjusted for inflation and then it uses that to figure out what its budget will be for 2005 for extensions attributable to new growth in customers and energy sales?
A. Could you repeat that?
Q. Sure. I guess it is, that's a mouthful. Let's put it this way. In doing your budget for 2005 do you look--and trying to figure out how much your extension budget should be based on your expected growth in new customers, you look to your experience in the preceding year as to how much it costs to hook up new customers?
A. That's correct.
Q. Okay. And that there's a specific formula you use and that's in the Attachment A?

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MR. KENNEDY:
A. Yes, that's correct.
Q. And as indicated in Attachment A, you take the historical labour cost per customer, which is the historic actual labour cost, minus any special projects labour costs and then you divide it by the number of customers, new customers that have come on the system, correct?
A. That's correct.
Q. And then you'd do the same calculation for your non-labour costs, so presumably that's materials mostly?
A. Yes, that's correct. Some material and--yes, that's correct, yes.
Q. Okay, and again you except out any special projects that are special?
A. That's correct.
Q. And then you take a total of those, so you just add those together, and then you take that total and you divide it by--you do it for five years and you divide that by five years in order to get an average of what that historical costs, including both labour and non-labour has been for the cost per total new

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customer?
A. Yes, that's correct.
Q. Okay. So if your actuals are increasing, your average historical expenditure per customer is increasing, correct? If the actual cost of labour and non-labour and the combination of the two, year over year, is increasing, your average is going to increase; one follows the other?
A. Yes, you would think, yes.
Q. So if your actual costs are increasing, it places a, if I may, an upper bias on your calculation of what your budget should be for a given budget year. So for instance, 2005 being based on a record of increasing historical expenditures to hook up new customers, that trend would be reflected in your budget in 2005 by a corresponding increase?
A. The budget is formula driven to a certain extent, based on history, based on our per unit costs and we will look at the budget and see how it compares to previous years and see if it makes sense too. There's a certain override that we will look at the budget and

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it's formula based to an extent, but if there are special projects or if there are special things we know about that could happen, we will put those factors into the delegation of this budget as well. So it's formula driven, but there is some--there's some judgment got to be exercised.
(12:15 p.m.)
Q. So Mr. Delaney, accepting your explanation that some of the reason why the unit costs have increased is attributable to the fact that your doing early bills in some areas where the number of new customers is low and so the unit cost ends up being high. In effect you're almost sort of over building an area in anticipation of further growth in the future occurring, correct? In other words, if you have a hundred new customers move into a subdivision, you build your substation on the basis that the subdivision plans to have a thousand new homes?
A. Most subdivisions now are built in phases and we use our judgment in terms of how much of the subdivision you will build at any one time. We also got to be very cognizant that

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after the houses get built, it will get more expensive for us to get in there and get our stuff--like, get our work done after the houses are built, so we tend to try to get ahead of the housing.
Q. And so is it safe to assume that that unit cost per new customer should start to decrease as we move forward and these areas where you've experienced a necessity to build plant in excess of what was needed and drive up your unit cost will begin to reverse as new customers come into those same areas?
A. I think that's true. If we see a downturn in economic growth, in terms of residential subdivision construction and commercial subdivision construction in the Northeast Avalon, where we've seen most of the growth, if we see that turn down, I would expect our per unit cost to hook up a new customer would decrease.
Q. So can you give the panel any indication of when you would expect for us to hit that tipping point? Is that something that you can foresee?
A. We use the forecast of the Conference Board of

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MR. DELANEY:
Canada and we look at other forecasters in terms of, you know, our director of forecast produces for us the forecast based on the economic information he has in front of him as to where he sees growth going in the next year. And like all forecasts, it holds an element of uncertainty.
Q. In a case of the extension's budget for the unit cost, would there be a labour component in that extension's budget?
A. Yes, absolutely.
Q. And in accordance with the way this works now, all the labour associated with that extension gets booked as capital, correct? It's treated as a capital expenditure?
A. Yes, all the labour associated with an extension would be charged to the capital expenditure, yes.
Q. None of the labour associated with the new customer would be clerical in nature, would it, that would involve just signing up a new customer? Like none of the labour I see here, for instance, in your expenditures related to growth would be clerical, the signing on of a

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new customer in your customer service department, the more operational related -
A. Subject to check, I don't think that that's the case that our costs and our representatives would charge any portion of their time to capital.
Q. Okay. Just in the ten minutes we have before lunch, Mr. Delaney, I wonder if we could have a chat about the Wesleyville Gas Turbine overhaul. And I think the first place to start would be in the variance report, which is volume one--it's not actually called variance report, it's called the 2004 Capital Expenditure Status Report, and it's the attachment A.There you go, and it's item 6, Chris. Here we go. Do you have that in front of you now, Mr. Delaney?
A. Yes.
Q. Okay. And you've already spoken about this in your direct presentation. I just have a couple of questions first relating to your variance report here. It is indicated that the budget originally for this project was one million six hundred and seventy-four thousand and it ended up coming in at three million two

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hundred and thirty-three thousand for a variance of one million five hundred and fifty-nine thousand or 93 percent over budget, correct?
A. Yes, that's correct.
Q. And that number, one million six seventy-four, that was the original budget put forward by Newfoundland Power as part of its 2002 Capital Budget Application? Am I gathering that correct because it says 2002 project?
A. Yes, that was put forward in 2002.
Q. Okay, so it was work that was going to be carried out in 2002?
A. Exactly, correct.
Q. And then just before you went to actually relocate the gas turbine in accordance with that proposal that was approved by the Board, there was a major system failure in the Burin Peninsula?
A. Yes, that's correct.
Q. And the gas turbine, I take it, played a role then in addressing that system failure. It provided energy to the system during the failure?
A. Yes, it did, yes.

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Q. And so until you felt--until Newfoundland Power felt confident about what it was doing down in the Burin area to address this system issue, it kept the gas turbine down there? It decided to postpone and delay the move?
A. Because of the system problem, yes, we decided due to the customer concerns that arose as a result of that long outage, we decided to defer the relocation into the subsequent year.
Q. And so was the work on this commenced in 2003 then? Once that Burin issue got resolved, did the project actually start in 2003?
A. Now there may have been some work in 2002, but the project began in earnest in 2003, yes.
Q. And I understand it was completed in the second quarter of 2004? That last paragraph there actually if you scroll down please, there's another paragraph underneath that relating to this. You'll see it says the gas turbine was relocated and commissioned for operation at the end of the fourth quarter 2003. And then the work associated with upgrading the lube oil cooling system, fuel system and providing remote control was completed in the second quarter of 2004?

MR. DELANEY:
A. Yes, that's correct.
Q. Okay. Earlier in that paragraph or the paragraph just above that one, it indicates that following the decision to postpone relocation and retendering in 2003, the contract costs to relocate the gas turbine increased by four hundred and twenty thousand to seven hundred and seventy thousand. So do I gather correctly then that Newfoundland Power went back out to tender in 2003 to seek new bids for the relocation of this gas turbine?
A. Yes. we did, we went--after our decision to defer the relocation, the contract we had in place on which we built the estimate was no more, and so we went back to tender to get revised estimates for relocating the gas turbine.
Q. Right, and it says, as a result of that, the contract costs to relocate went up by three hundred and fifty thousand and that ended up increasing your interest during construction charge by ninety-six thousand?
A. I think the contract to--okay, the original

contract labour cost was three fifty and it went up to seven seventy for a different of four hundred and twenty thousand.
Q. Oh, I'm sorry, increased by four twenty?
A. Yes.
Q. Right, okay, so the labour increased by four twenty per the replies you got back on your tender, and that increased your interest during construction--well, just as we said the postponement of the project, so it may not be particularly related specifically to that increase in contract costs, it just overall, the delay -
A. The delay is responsible, as we put in here, for five hundred--well, it's four hundred and twenty plus ninety-six thousand in direct increase in costs, yes.
Q. Right. Now, the postponement itself of the project wouldn't necessarily increase your interest during construction, it's the actual increase in the project costs caused by the postponement that increased your interest during construction?
A. Ah, I think you're going to have to repeat that.

Q. Want me to say that again? Okay, I just want to make sure that we're clear on the record, any increase in the interest during construction charge would be attributable to the increased cost in the project attributable to the postponement, not directly related to the postponement; in other words, just because you postpone a project doesn't mean your interest during construction increases. It's only if your cost increases as a result of your postponement that your interest during construction will increase?
A. No, I think the fact that the project took longer to do and spread it over a longer time period would increase the interest during construction.
Q. Okay.
A. If given two projects that were of the same value, if one were done in a longer period of time, relative to the other one, that would have a larger component of interest during construction.
Q. Okay, and then we had--and I think you referenced this that there was assessment of equipment during the dismantling of this

project which indicated that you needed to refurbish some equipment you hadn't expected to refurbish and that costs an extra five hundred and eighty thousand dollars?
A. That's correct.
Q. Okay. And then you've got, the last sentence, additional scope of work, along with delays in completing that project resulted in additional engineering and project management and supervision costs totalling 460,000?
A. Yes, that's correct.
Q. Would that be mostly internal labour?
A. That's mostly internal, yes.
Q. Okay. So Mr. Delaney, there must have been some point in time, in 2003, before you actually started this work, where you realized that the project budget had increased fairly dramatically. Before you started the work, you must have known that, for instance, as is indicated here when you re-tendered, that your contract costs had gone up by $420,000 alone, and the nature of the project seemed to change the minute you got into it. I'm just wondering why Newfoundland Power wouldn't have sought approval of the Board for this project,

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MR. KENNEDY:
on the basis of these new figures that Newfoundland Power was aware of?
A. As we became aware of the variance in the project, it was reported to the Board in our quarterly reports of variance to the Board. The scope--it's my understanding that should the scope of the project change, then we would come back to the Board for approval. Through the course of this, the scope of this project didn't change. It was taking a gas turbine from Salt Pond and moving it to Wesleyville. The project remained the project. There were significant variances and those were reported to the Board through our reporting of quarterly variances to the Board. So because the scope did not change or the nature, the entire nature of the project did not change, we did not come back to the Board for specific approval.
Q. Okay, Mr. Delaney, I just got one more sort of area I wanted to cover with this and it's something sort of, I think, could do with a little bit of an explanation. And this refers to a report by Rolls-Royce and we'll find that

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in--this is in volume 2 of the Application under Energy Supply and then there's an appendix 2, No. 2. And then there's an Attachment A, and could you just describe, Mr. Delaney, what it is that we're looking at there on the screen?
A. This is a report compiled by Rolls-Royce who are the original equipment manufacturers of the Avon gas turbine, so they are the specialists in this particular type of gas turbine. This is a report that they filed on December 7th of 2003. Where is this to? Appendix 2? Okay, this is a -
Q. Yes, this is under volume 2, "Energy Supply", Appendix 2, and then there's an Attachment A.
A. So this is the Rolls-Royce recommendations for the work required on the gas generator unit. This is a report that Rolls-Royce provided to us after we had installed the unit in Wesleyville.
Q. Okay. Can we just keep that handy please and then can we just go to PUB-31.1. There we go, thank you. And this asked a question specifically about a passage that's in the Rolls-Royce report and that passage is at page

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2 of the Rolls-Royce report under "Conclusions". And if we could just keep that then, please, and then just toggle back to the Rolls-Royce report and go to page 2. So that's that--that's the energy supply appendix 2, Attachment A. Yes, there we go, and if we could just go to page 2 of that. And right there, 2.1, paragraph 2.1 and the conclusion was, "The gas generator was suspected prior to the move and the recommendation at that time was to have the unit sent to an approved overhaul facility for repair prior to running the unit. This visit was not different in that the customer was informed that the gas generator is in poor condition and should be overhauled as soon as possible to prevent the possibility of a catastrophic failure." Now, I think you just confirmed there that the unit was actually run in April of this year in order to address a system outage up in the Bonavista Peninsula, is that correct?
A. Yes, it was, on the Bonavista North.
Q. Bonavista North, is it? So that would sort of run somewhat counter, I'd suggest to the conclusion that Rolls-Royce representative

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gave that it should be overhauled prior to running the unit?
A. I'll give some history on this to answer the question and to put it in perspective. In 2000, we had Trans Canada Turbines come down and did a detailed analysis of the Wesleyville gas turbine involving internal inspection using boroscope and evaluation of the unit, and it was given a clean bill of health. In 2003, when we started the move of the gas turbine from Salt Pond to Wesleyville, around March, we had Rolls-Royce come in and do another boroscope analysis inside the machine. The purpose we did that, was let's see what this thing looks like inside now, so after it's done, to make sure everything worked right from before the move, after the move and if something should happen in the interim, then our contractor, who was in charge of the relocating, would have been responsible. When in March, when Rolls-Royce did this analysis, this is the one that they refer to, the prior analysis, they recommended that we overhaul the machine. So at that time we were faced with a decision. We had delayed this project

MR. DELANEY:
one year already. We had reliability problems in Bonavista North that had to be addressed, so we made the decision to move the gas turbine. I personally met with the representatives from Rolls-Royce to field out their judgment with respect to this move, and based on my meetings with them in March and again later on after the December inspection, I decided based on our use of the gas turbine that we could move this project into 2005. Now by that, what I mean is when Rolls-Royce were looking at gas turbines and their judgment is, you know, is very good, they're the specialists, they are the experts in this field, but we run our gas turbine for short durations, very small short durations, time at a time. This gas turbine is not on, staying on. So my discussions and looking at the report with the situation we were in, we used our best engineering judgment that we would continue on with the unit, continue on with the project, get it in place, test it, run it up, it's been successful so far and we bought a project before the Board now to get this

overhaul done next year. So that's the background on the decisions made with respect to the overhaul of this gas turbine.

Q. And, Mr. Delaney, you indicate in response to PUB-31.2 that the cost that could be considered to be now need to be duplicated in removing this gas turbine unit to get an overhaul and then reinstalling it, for what would amount to a second time in its present location in Wesleyville, are, you quote--and that's the bottom paragraph at line 24, "a relatively small part of the overall project." Could you let me know what is considered to be a relatively small part of the overall project in a dollar figure?

A. We--that would be less than five thousand dollars.

Q. So two to four days?

A. It would be less than five thousand dollars.

Q. You indicated, I think under your direct presentation that--and also in reply to PUB 2.1 and 2.2, that the decision about whether to actually purchase a used gas turbine, I guess, versus overhauling your existing unit, is one that you haven't decided yet. It's one

that you will look at, at the time?

A. That's correct.

Q. Okay, so is it you're seeking approval from the Board then under this project to do either one of those? Because the way the project is presented, it's an actual approval for the turbine overhaul, but you could determine in 2005 that you may actually, in fact, purchase a used gas turbine?

A. Yes, we'll solve the problem for whatever is least cost. We have there the estimate to overhaul the unit that we've gotten from Rolls-Royce and their facility that overhauls these types of engines, but at the same time, you know, we know there is a market out there, so if in fact we find that replacing the unit is a more cost effective solution, then, of course, we would look at that.

Q. Chair, that's probably a good place to break for lunch.

CHAIRMAN:

Q. Fine, we'll come back at 2:00. Everyone okay with that? Thank you.

(12:37 p.m.) (ADJOURNED FOR LUNCH)

(2:00 p.m.)

CHAIRMAN:

Q. So, if Mr. Delaney is ready, Mr. Kennedy, I guess you want to resume?

MR. KENNEDY:

Q. Yes, Chair, I have a few more questions for Mr. Delaney, but I think this will hopefully might finish today, so. Mr. Delaney, the first thing I wanted to ask you a question about was just an issue concerning the contributions in aid of construction and how that works just so we can get it on the record. I think the first place to start would be the variance report again. And that's Volume 1, yeah. And the status reports, yeah. And we're dealing with the attachments, A, and we're dealing with items 13, 14 and 18, so 13 first. I just wanted to first to set the groundwork, Mr. Delaney. And these are the ones that I've picked out of the variance report that in explaining a variance provide a commentary that had to do with the over costs or overrun, if you will, was attributable, at least in part, to requests by third parties. One was relating to the rebuilding of transmission lines for 188,000.

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MR. KENNEDY:
And then item No. 14, and these were an increase in your extensions budget related to customer driven projects. Examples of significant projects include Humber Valley Resort development in the Corner Brook area, the INCO, Voisey's Bay demonstration plant in Argentia and a line extension for various services previously served by the distribution system operated by the Argentia management authority. And then if we could just go over to 18? This is to explain the variance of $385,000, which is actually I've worked out 164 percent over budget on that item. The variance is a result of higher than expected number of third party requests to relocate distribution lines. And they were completed by Department of--for Department of Transportation work as well as replacements required by the cable television company. Now, just setting that as the groundwork, I wonder if we could go to PUB-59? And this is relating to that note 14 on the extensions and explaining the variance of the million 898. And then there's a list there of the location

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of the project and the number of customers impacted and the total cost and the contribution in aid of construction to recover or recovered and any other details. And flipping over to the other page, the page 2 of 2, there's two there that, I guess, caught my eye, three, really. There's the Humber Valley Resort, Phase 2, Corner Brook area. Number of customers, 16 residential. Total cost, 338,360. And the contribution in aid of recovery was 29,298. And similarly for your--the Phase 3, which is split, I guess, between residential and commercial, project costs of 108,000, 18,867 as the CIAC. But then if you look at the next one, it goes St. Fintan's Cell Site, Stephenville area, one commercial customer, the cost of the project was 64,000 but the contribution in aid of construction was 85,777. So, I'm wondering if you could provide an explanation, first, why the contributions in aid of construction for, in particular, the Humber Valley projects seem to be so low in comparison to the cost of the project, what would be the policy followed there, and secondly, why in the case of, for

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instance, another project like St. Fintan's Cell, the contribution in aid of construction was actually in excess of the project cost?

A. When we determine the CIAC that's required for any particular extension, we're governed by the CIAC policy as approved by the Public Utilities Board. The concept behind that policy or the underlining the rules of the policy is that you look at your customer and try to--and you estimate the future revenue stream from that customer. And for each customer we will provide a minimum, an investment in terms of hooking that customer up to the system. So where the customer's future revenues are not compensatory or greater than that investment that we'll lay out first, then that customer would be required to pay a CIAC and this is governed under the CIAC policy. So in the case of the Humber Valley Resort we'd estimate our cost, estimated the future revenue stream from Humber Valley Resort, CIAC policy tells us what our investment should be, so the difference between what was needed to, you know, finance this thing, between what we

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would get, the difference is what the customer has to make up in terms of the CIAC upfront, the CIAC cost. It's done as per policy approved by the Board on an individual basis. The Board would have specifically approved both of those projects and the detailed calculations therein. In a situation like the St. Fintan's Cell Site, in some situations where we're building extremely long lines to service one very small customer, in this case a $64,000 line gone in to serve a very small load, we also look at the operating and maintenance cost for that line going down, going into the future. And in some cases it will actually be the case that the customer has to pay us more upfront than the cost of building the line because that will take into account the operating and maintenance cost we have to recover over time. So in some cases CIAC could actually even be bigger than the capital cost. But all of these are done, approved by the CIAC policy of the Board.

Q. And that would apply if we look at PUB-60, just so we're clear on it, that there's another Humber Valley Resort, Phase 1, Corner

MR. KENNEDY:
Brook area, if you just scroll down there, for a project cost of 219,813, but there was zero dollars in contribution in aid of construction. And again, that would have been something in accordance with the CIAC policy?
A. Yes, that's correct. We would have done the calculation and determined that no CIAC was involved in that, in Phase 1 of the Humber Valley project.
Q. And what goes into your invested plant and therefore constituted part of your rate base is the net of those two, it would be the net of your total project cost less your contribution in aid of construction?
A. I understand that to be so. I'm not an expert on rate base, but there is a line item in our rate base calculation for contributions for country homes and contributions in aid of construction. Lisa Hutchens would be our expert in terms of the application of that formula.
Q. If we could go to PUB-63? And if we could just scroll down? This is relating to the note 18, which is the relocation and

replacement of distribution lines for third parties, and that was the one that had the variance of 385,000 but was 164 percent over budget. You've got Aliant in there, September, 2003, forecast cost, and this is for year to date in June, 2004, 214,000 and then the recovery amount as 25,000. So, again, is that done in accordance with CIAC policy then, the recovery of project cost for the relocation of lines specifically requested by third parties, presumably Aliant in this case?
A. The recovery of the cost associated with relocates and rebuilds for Aliant are governed under the support structure agreement that we have with Aliant that we entered into in 2001. There's a myriad, there are a number of combinations, a number of various scenarios out there with respect to the replacement and relocating a pole that we could encounter. Generally it works like this, when Aliant needs to build new--bring in new wires, put up new wires on the pole, if the poles have to be replaced or relocated to accommodate that, then we pay the cost of the pole, because

we're the landlord, sort of a landlord rental agreement, and Aliant would pay for our transfer costs, those are the costs associated with transferring our line off the old pole onto the new pole, and we apply a betterment in that regard. So looking at this on the surface, these 25 small projects, it looks to me that there's a fair amount of those that would be old plant. So when we transfer from the old pole to the new pole, put in our new structures, there's a benefit derived to us in terms that we have a new, all the attachments to the pole are new versus the old ones so there's a betterment calculation that takes place there.
Q. Mr. Delaney, just switching topics. I wonder if we could look at PUB-68? This again relates to the capital expenditure status report. And it's relating to note 23 in that document which is additions to real property and it was a reported variance of $97,000. And you'll see that item No. 4 in that table there's mechanical maintenance shop, Duffy Place, a forecast expenditure in 2004 of $49,000 for a variance of $49,000 because you

hadn't actually budgeted anything for the mechanical maintenance shop in your 2004 capital budget application. Is that correct?
A. That's correct.
Q. Okay. So if we could just keep that in mind and then go to Volume 2 of the application and general property, Appendix 2, page 1? Now, Mr. Delaney, item 1 there is the Duffy Place renovate maintenance centre, cost of $100,000, which is part of your overall project cost for additions to real property of a total of 325. And I had--am I understanding correctly that the $49,000 expenditure in 2004 which related to the mechanical maintenance shop in Duffy Place is the same, is that the same thing that we're talking about here, Duffy Place renovate maintenance centre, are they one and the same? Should they have been treated one and the same, as the same project, in other words?
A. They are the same facility.
Q. I guess what I'm asking is you've got $49, 000 that was spent on that facility related to, as it's described, installation of--renovations to the Duffy Place facility to accommodate the installation of office furniture and work

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MR. KENNEDY:
stations for additional staff assigned to work on the asset management initiative. And the description is in this document we've got on the screen is to renovate the maintenance centre to accommodate generation mechanical maintenance personnel. So, is that the same-- I guess what I'm asking is is you spent $49,000 in 2004 which wasn't specifically budget approved, but you have $100,000 budgeted in 2005, and it seems to be one and the same, that the amount in 2005 is just a continuation of something that you started in 2004, and if so, the obvious question is, why wasn't this presented as a budget, a project in 2005 of $149,000 and to do the project with the specific approval of the Board?

A. The reason it wasn't presented in 2005 is because we had to do something right away. And I guess this points to the problems with defining a project. I'll describe what happened. In 2003, 2004 we embarked on asset management initiative in Newfoundland Power. It's about getting into predicting maintenance. We bought some information

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technology in, some support. The strategy is all about planning jobs, scheduling jobs, doing it right the first time, being productive, being efficient, extending the service life of the equipment, all these things. To accomplish that we had to put the team together in one location. And it was an oversight in the 2004 budget. There should have been money allocated in 2004 to achieve that purpose. We put our group together in a garage, it's a building adjacent to Duffy Place that at one time had been a vehicle service centre. So what we basically had there is we had our planners and schedulers in the building. Because of the oversight we never had the money. We had planners and schedulers in that building, working PCs and our spare parts put there, our tools, try to bring the team together, asset management. There was insufficient lighting, the technicians were working in the loft of the garage, there was a set of wooden steps that went up to that loft that were unacceptable, it was dusty. It was a garage environment. So we looked at this earlier this year, said

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this is unacceptable, we had to do something here. We went out and got a plan put together and we had a design done as to for office area for our staff, staging area, proper storage of the tools and equipment. And the whole plan cost $150,000. So, this year we are under a lot of pressure with respect to capital. We are in--we deferred some projects, as I highlighted earlier, to manage the overall capital expenditure to get it to match budget. In this year I did not want to take the full $150,000. I wanted to address the immediate problem of getting the employees off of that loft and into suitable work stations. So, yes, we could have put a project together for 150,000, brought it to the Board and immediately deferred two thirds of it, but we've been quite open and this is disclosed here in terms of the thing to do was to get--I wanted to minimize that expenditure, do as little as I had to do this year. We got our staff--the project is done. We got our staff downstairs in suitable, you know, working environment and next year we plan to complete the rest of the project which will be a

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staging area for our mechanical maintenance men in terms of their spare parts and their equipment and have the team together, and it's been quite successful for us.

Q. Okay. I have one more series of questions relating to the variances and the definition of project, Mr. Delaney, and that's if we could go to the status report again and the Volume 1 status report and Appendix A, and it's item 1? There we go. And this had to do with the hydro plant's facility rehabilitation which went 252,000 over budget, which I calculated at 22 percent. And it indicates in here that the variance is primarily the result of implementing demand metering in plants for the hydro demand energy rate, installing fire and intruder alarm in our hydro plant buildings and an increase in the Rattling Brook generator rewind. Then it goes on to explain that the demand metering in the plants is required to implement a demand energy rate for Hydro's billing of Newfoundland Power. And the alarms project was not originally included in the budget for 2004 as the requirement for alarms was only recently

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MR. KENNEDY:
identified after completion of independent risk inspections of the various plants. Now, if we could first just go to PUB-41.1? And the question asked, "Explain why if the"--and it was quote from that section, "the alarms project was not originally included in the budget for 2004, why if that was the case the Company did not seek approval from the Board prior to proceeding with the project?" And the reply is that, well, under Section 41 of the Public Utilities Act approval is only required if the cost of the construction or purchase is in excess of 50,000 and the cost to install the fire and intruder alarms was forecasted at 48,000 and consequently specific prior approval of the Board is not required. Now, I wonder if we could just keep in mind that reply now look at PUB-48? And PUB-48 indicates that after a breakdown of the 252,000 overrun under this item and as is indicated in the earlier reply, some of this was attributable to a metering purchase for the proposed demand energy rate and that as indicated in this chart, while the budget for

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that was zero, because it wasn't anticipated, I guess, at the time you did your 2003, you know, drafting of your 2004 capital budget, you're now forecasting $100,000 expenditure under that item. And I guess in light of the reply that, well, you didn't seek approval for the fire alarms because it was under 50,000, this item is clearly above 50,000, and I'm wondering if the Company has a position on whether it intends to seek approval of the Public Utilities Board of that budget item as a separate project?
(2:25 p.m.)
A. Yes, we do. When this project came to our attention, there was some urgency in getting some work done. The demand rate will be implemented, is said to be implemented on January 1st. We had quite a bit of work to do in our hydro plants and our thermal plants to get the proper metering in, so there was some sense of urgency in getting this project off the ground. To date we've spent approximately $20,000 and we anticipate that we will come before the Board to seek approval for the forecast--for the amount required.

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Q. I just have one more series of questions, I think, Mr. Delaney, and that's relating to your transmission rebuild part of your project. And it says specifically there's two projects in there, B 29 and B 30. And this is relating to the rebuilds of 43L and 124L, is that correct?
A. That's correct.
Q. Okay. And as I understood it, it was to address some SAIFI and SAIDI issues, is that correct, on those lines?
A. No.
Q. Oh, okay. So what's the justification for the project then?
A. The justification for 124L is because the line is, there's not sufficient clearance between the line and the ground and it is a public safety hazard.
Q. So, when you say rebuild, is that--that doesn't involve a rebuilding of your towers and all the associated hardware then, does it?
A. Yes, it does. It's a complete rebuild of the line.
Q. And is that only way to resolve an issue with insufficient ground clearance?

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A. It is.
Q. Okay. And what about the justification for 43L?
A. 43L is a line that's build in 1946--excuse me. 1956. Given the age and the overall deterioration of the line it is our engineering judgment that it needs to be replaced, the entire length of the line which we will--we have divided the project into three parts and we anticipate rebuilding that entire line over the next three years.
Q. Okay. Could we just go to PUB 9.3, please? And I'm interested in the SAIFI and SAIDI specifics for your 43L line, sir. And to a layman's interpretation of this data it would seem to suggest that your SAIDI and SAIFI figures for 43L are better than, generally better than your system average and in actual fact you've had no interruptions there in 2003 or 2004 and none in 2001?
A. That's correct.
Q. And if you go over to the Attachment A to this response, we look at page 2 of 3, and we look at the actual comments relating to what caused the outages that are reported in 2002 which

MR. KENNEDY:
has got the SAIDI in 2002 of 1.9449, which is above your system average of .9 and you have a SAIFI on 43L in 2002 of 4, which is well above your system average of .84. But then if you look at the reasons, there's three of them, a trip due to washing down insulators, line tripped while crew were washing down insulators and line crew--line tripped while crew were washing down insulators. And the other ones are related to salt spray. So I guess I'm wondering first, in light of the fact that your SAIFI and SAIDI statistics seem to be much better than your system average and that the majority of the reasons for the outage in 2002 are actual human intervention, if you will, by Newfoundland Power's own employees why a rebuild to 43L is going to improve things?
A. When we evaluate transmission for replacement, SAIDI and SAIFI are considerations, although they are not all we consider. SAIDI and SAIFI in terms of planning I more or less look at those statistics in terms of from a customer service angle because it's what the customer

sees, it's a customer service measure. With respect to the rebuilding of transmission there are other factors that have to be addressed. 43L is a line where the probability of cascading is very high. The way a transmission line is built, it's built at least cost, long distances, straight lines. So if you should get a failure in the line in a particular location, it can tend to cascade and you'll have a very, very big problem on your hands. And 43L, of the lines we have, is very prone. It's prone to that cascading event should something fail.
The poles on the line are incredibly dried out. We've walked the line. You can touch the line with a hammer and the wood chunks right off the poles. Our linemen, who are most experienced with poles, have a lot of difficulty with 43L because of the shelling phenomenon. As you put your climbers in the pole, it doesn't--you don't hit the heart wood, so to speak. You're only hitting the shell, and it's shelling off. They're not the safest poles in the world to climb.
So knowing how the line is designed, with

respect to this cascade issue, knowing that the poles are dried out, feedback from the line department, when you look at--when we're looking at 110 transmission lines out there, what causes us the most concern, in terms of a big event that's going to cost us a lot of money, it's not, you know, a beyond compare (phonetic) so to speak, that if you get a big cascading event, we could be into a million dollar or more type of problem down on this line. I think the time is right, right now, to address the problems on 43L over the next three years and get this line rebuilt.
Q. That's all the questions I have, Chair. Thank you very much, Mr. Delaney.
CHAIRMAN:
Q. Okay, Mr. Kennedy. From here, do you want to--do you have any questions?
MR. ALTEEN:
Q. I have one small question on redirect. I can do it after you or before you, Mr. Chairman. I'm free.
CHAIRMAN:
Q. Well, why don't you do it now so it keeps things in order.

MR. ALTEEN:
Q. Can we see RFI PUB-31.2 please, Colleen? Mr. Delaney, this is a response to an RFI in relation to the proposed Wesleyville gas turbine overhaul, and in answer to a question from Mr. Kennedy as to the costs of potential duplicated costs associated with the overhaul, you had indicated that you had expected them to be in the order of or just less than $5,000. The last sentence of that RFI indicates that there's a benefit of deferring--of having deferred the gas turbine for a year. Can you ballpark that, just so that the Board would have the benefit and the cost in front of them?
A. Yes. The approximate benefit of deferring the overhaul of the gas turbine is somewhere between 85,000 and $90,000, for having deferred that project one year.
Q. That's all, Mr. Chairman.
CHAIRMAN:
Q. Okay, Mr. Alteen. Do you have any questions, Commissioner Vincent?
COMMISSIONER VINCENT:
Q. No, Mr. Chair.

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CHAIRMAN:
Q. Any questions, Commissioner Martin?
COMMISSIONER MARTIN, Q.C.:
Q. No.
CHAIRMAN:
Q. I have a couple, Mr. Delaney. Just a couple of points of clarification. How old is the gas turbine, by the way? I didn't find that anywhere in the documentation.
A. Subject to check, I think it's 36, could be 37.
Q. Okay. I wondered. If you look at page 10 of 73 of your Schedule B, Volume 1, page 10, do you have it in front of you there? Or you're waiting for the screen? Okay.
A. I was waiting for the screen as my -
Q. Well, let's wait for it.
A. For things unforeseen? My binder is a little bit -
MR. ALTEEN:
Q. Next page, Colleen, please.
CHAIRMAN:
Q. There we are.
MR. ALTEEN:
Q. That's it.

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A. Okay.
CHAIRMAN:
Q. Yes, that's it. I'm using this as an example really, but it's the first one that I came across. In the project description, the work includes--I'm looking at the second paragraph--includes the replacement or rehab of major components at the following plants, and you name four or five plants there. Okay? Then when you get down to the operating experience and you talk about the project costs over the past five years, you include certain dollar figures, and my question is that these dollar figures that are included there are not necessarily dollars spent on the five named plants in the first section of the project description, is it?
A. That's correct.
Q. Hydro plants facility we have is a category or a classification. No, it's a project title, I'm sorry, classification is energy supply?
A. It's a project title within energy supply, yes.
Q. Yes. It's a project title within energy supply.

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A. So from year to year, there would be different plants with various work done on it, and that project cost, the history is for the project, not the plants.
Q. As a matter of fact, the dollars that are shown here spent between 2000 and 2004, none of those dollars, conceivably, could have been spent on the five plants named here?
A. That's correct.
Q. I understand, okay. Just wanted to get that clarified. And I wonder, in light of that, what value the historical cost has in, let's say, evaluating the project? Maybe there is some value. But when I look at this and you're saying you're going to spend one million eight eighty-seven on these five plants in 2005, then I come down the sheet and see, well, you've spent X number of dollars on this particular classification over the past five years, but there's no necessary relevance between the two numbers?
A. No, there isn't. However, in Volume--we have the details for each of those projects.
Q. Yes.
A. In Volume 1 or Volume 2 later on.

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Q. You probably will find it further on?
A. Yes, you could find it further on.
Q. Yes, but looking at the face of it on Schedule B, page 10 of 73, you could be mislead by the numbers, and that may be as much our fault as yours because I think we asked you to show these historical numbers and I'm wondering if we were specific enough, in terms of what numbers we were looking for. It's a question that I don't intend to deal with today, but certainly one that we may want to explore after this hearing is disposed of.
MR. ALTEEN:
Q. It's a valid point, Mr. Chairman. There's no doubt about it. There's no perfection in this.
CHAIRMAN:
Q. Okay. Look at page 29 of 73. I'm in the same Schedule B. Here we are. Again, refer to the project cost table that you show, and you have a dollar figure of two and a half million, approximately, for 2005, and then you show future years. 2006, 5.1 million, and then in the period '07 to '09, which is inclusive on a three-year period, I presume, it's 15 1/2

CHAIRMAN:
million. I have two questions in relation to that. One is would reliability suffer if these amounts were spaced out over a longer term? And I'm particularly talking here about the amount you show in the '07 to '09 period. Would there be any detrimental impact on reliability if that were spaced out over a longer term? And before you answer that, the second question I have is, what benefits would there be to shortening it up or compressing the term? And I'm thinking of the advantages that you might pick up in the operations costs side of the project, it's impact on your operating costs if the reliability is improved over a shorter period. And I'm sure you follow what I'm saying here.
A. Yes, I know what you're saying.
Q. Okay. So maybe you could deal with both parts of that, Mr. Delaney.
A. Okay. There's a short answer and a bit of explanation behind it.
Q. You give whatever answer you want to give, because we've got lots of time.
A. The reality is if we extend this out over a longer period of time, there would be some detriment to reliability. Reliability will suffer to some degree if we extend it over a long period of time. If we shorten it up, yes, we could bring our operating costs down.
Q. Okay. Have you done any calculations or have you--well, in dealing with projects such as this one and looking down the road four and five years, is it your practice to do an assessment of what those costs are for the longer term or the compressed term?
A. Exactly. We plan in 2005 to focus some engineering in studying our transmission line system. I'll describe to you the situation we're dealing with. In the plan, you'll notice, you notice correctly that transmission line expenditures seem to be increasing in the plan. What we're dealing with, with Newfoundland Power, is--I try to stay out of the chief engineering. Around the early 60s, there's a divide in transmission line construction. After the early to mid 60s, it's not a--this never happened on one day. It kind of happened over time. Transmission line assets became engineered. They were designed. They were designed, surveyed, designed, designed for ice loading, designed for strength, wind, all these things, you know.
Q. They got more sophisticated.
A. More sophisticated.
Q. Yes.
A. Prior to that time, and you can see we got a lot of these lines out there, it was we went out with a bunch of poles and wires and built lines. It wasn't as sophisticated. So those lines now, 60, sort of the age now, 40- 50 years old, you know, that type of age frame. So I asked one of the engineers, the engineer in charge of transmission, how much of this do we have out there that's substandard? Let's call that substandard line versus standard. And how much would we have to spend--this is very preliminary analysis--to get rid of it all in ten years? Okay, how much would we have to spend? So about 25 percent, 25- 30 percent of our line is of that nature. It's old line, wasn't engineered to standard. There's clearance problems. It's just getting old and deteriorated. And I described to you transmission, when you have transmission problems, they tend to be very expensive when you have them.
So if we were to approach that over the next ten years, so that no line ever exceeded, the line built in 1960 would be replaced in 2015. So you're talking 55 years old. How old is it? What have we got to start doing? How much do we have to start spending? So we're looking at it from that perspective that we don't want to snow plough all this work and then suddenly get out there in 2009, 2010 with $10 million transmission projects with--you know, and suffer the reliability consequence.
So realizing that we have these lines--and another good point to make about these lines is a lot of them are on 35-foot, 30-foot small poles. You know, we call them the blackjack poles. When you find the deficiencies in the line, you know, you're throwing--you're putting money--you got to fix the deficiency. You got to keep it safe. So you're putting brand new insulators, brand new cross arms, brand new equipment on an old line and transmission is not something that you

MR. DELANEY:
just go in and replace a pole here, replace a pole there, like a distribution line. With transmission, you got to design the whole line because one pole is dependent on what the other poles are, in terms of their sizes and, you know, the strength of the line.
So realizing that we have a lot of old transmission, trying to look at the time frame, you know, how long are we going to run this stuff, you know, 60, 55 years old? We put the preliminary stages of a plan together that's telling us that we're going to have to start to up the investment in transmission or we're going to snow plough an awful lot of problems out five, ten-year time frame. So this plan does show some increase in that transmission line expenditure.
Q. Okay. Page 34 of 73, I just have a general question in relation to that. Your AMR meters, I think that's what you refer to them as, automatic--which enables automatic meter reading?
A. Yes, yeah.
Q. Yes. They've been increasing in numbers, in

terms of your budget, each year since approximately 2000. What do you anticipate will happen in this regard in subsequent years? I don't get that information from reading the information you filed, but I can see the advantages and the benefits of using automatic meters, you know. It enables you, I think, to do your meter reading faster. I think you addressed that here somewhere. Have you done any studies to indicate what will be the extend of that program, say over the next five or ten years? Do you have any feel for that or am I premature in the question?
A. No, no. It's very much on our mind. In 2004, this year, sometimes I get mixed up a bit in budgeting, but we're doing a significant number of AMRs this year. Getting our foot in the door, so to speak. Testing to make sure all this technology works. And the approach we took this year, there were a number of situations out there that were difficult to access, some problems where meter readers had, you know, indicated there were safety problems with respect to these meters. So we sort of targeted it that way, got our foot in the door

with AMR. We've proposed nothing in 2005, but in 2005, we're going to do meter reading strategy. You know, just look at meter reading totally within this company, all aspects of operating and capital expenditures associated with meter reading, and AMR is going to be a big part of that. It's just premature right now with respect to the longer range plan where we're going to go. But, we're going to take that on next year as a project to analyze, you know, AMR with the possibility of bringing it forward in 2006 as a capital budget item.
(2:45 p.m.)
We're looking at interest to a lot of things that are going on in Canada right now. There is a bit of momentum behind AMR. There's been some changes at Measurement Canada which have sparked things. Prior to--might have my time--prior to this year or last year, Measurement Canada required a much shorter interval with respect to the replacement of AMR meters.
Q. Yes.
A. And now they've changed their rules, so that

AMR now is no different than the other meters. So there's been a significant change in the operating cost of AMR going forward, in terms of staying compliant with Measurement Canada. So that's got our interest. There are big initiatives going on in Ontario with respect to smart meters. So we'll be looking at the meter reading strategy next year and AMR will be part of it.
Q. Mr. Delaney, you appear to be the type of a fellow who keeps up to date on what's going on in the industry. What's been the practice in other utilities with respect to AMRs? Is there much -
A. The most advanced -
Q. Is there an extensive use of them?
A. Yes, the most advanced is ATCO Electric in Alberta.
Q. Okay.
A. If they're not 100 percent, they're pretty well close to 100 percent all AMR.
Q. Yes.
A. Similar to us in a lot of ways, in terms of they're rural, very rural utility in Alberta. There's various starts and stops all over.

MR. DELANEY:
There's some significant things--I'm not totally up to date, because Ontario's market changes a lot, but the government has mandated some huge number, I don't know the number offhand, of smart meters that have to be installed by a certain date. But the leading utility in Canada, in terms of AMR installation, is ATCO Electric in Alberta.
Q. Do they have any statistics that you have access to, in terms of what cost savings there are? Because I can imagine a lot of cost savings that there would be for the utility company, the meter reading side of it, for sure.
A. Yes. I haven't asked them directly, but I sit on the distribution council of CEA with a representative from ATCO and the information, you know, is something I'll be looking at from him, in terms of when we do our AMR -
Q. When you do your long study. That's interesting.
A. Yes, there's a lot of potential in AMR.
Q. I'm sure there is, and you've really only scratched the surface.

A. Exactly.
Q. Yes. I had some concern at one stage during my reading of these documents about the prioritization of your distribution line rebuilds and so on, but I think that the RFIs that were put forward, I think you've answered all of the questions that I had. Here's an interesting item that really has nothing to do with what we're talking about. I just wanted to circulate this, and this is an opportune time, and it's almost break time. Ms. Blundon, would you? This is an article that appeared in the Financial Post and it's very interesting, certainly one that I'm sure, Mr. Delaney, it wouldn't be a surprise to you. But this, briefly put, is an article that talks about the transmission of broadband over electrical power lines, and this appeared in August of this year. And I'm wondering if you're aware of what's happening in this area, in your industry. I'm thinking about it as another source of revenue for your company.
A. Like pole rentals.
Q. Take away from the cost that the consumers are bearing now. But, this has potential, I

gather?
A. About a year ago, this was the big buzz in some distribution circles in CEA, Canadian Electrical Association.
Q. Yes, I read about it about a year ago, as a matter of fact.
A. Yes, about a year ago.
Q. Yes.
A. It's certainly technically feasible. It's a little bit farther along in Europe than it is here. But I would characterize all the projects going on in North America as experimental at this stage.
Q. Yes.
A. So we will follow it, with interest.
Q. Good. I just thought I'd throw that in there. I'm sure that your company is going to follow it with interest. It certainly has some potential, seems like. I did have one more question here. Yes. Just a matter of interest, more than anything. I came across the--this is having to do with, let's see, PUB 30.1, the questions that were put to you, in response to that, you put in a corporate distribution reliability review as an

Attachment A, and on page V-5, I think it's still the same document, V-5--was it V-5? Wait now. I'm sorry. V-12. There's just an interesting comment you had there in relation to the HUM-09 line in Corner Brook. "Tree contact continues to be a major source of problems with this feeder. The community desires the large trees in this area, however extensive tree trimming was completed on the feeder. We will continue to monitor" and so on. So I gather, in that particular area, which I'm familiar with, in terms of having been to Corner Brook several times over the years, that trees would be a problem there. Are the outages that you've experienced such that--well, let me ask the question in another way. Are the people that live in the area aware of the reason for the outages?
A. Yes.
Q. When they're caused by trees?
A. Yes. I'm from Corner Brook myself and I'm very familiar with the tree problems in Corner Brook. Yes, the customers are -
Q. So you don't get blamed for the outages?
A. Let's put it this way. After we have outages

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MR. DELANEY:
with respect to trees, we are out in full force trying to get trees trimmed. We try to make sure that it's top of awareness at the time, as well, because people will tend to forget that later on in the year.
Q. There's no coincidence in the fact that I ask that question and the other two commissioners on this panel are from Corner Brook, by the way.
A. And the witness.
Q. And the witness. Anyhow, that's all the questions that I had. Now then, Mr.--who's next? Mr. Kennedy?
MR. KENNEDY:
Q. Yes. Nothing arising, Chair.
CHAIRMAN:
Q. Nothing arising?
MR. KENNEDY:
Q. No.
MR. ALTEEN:
Q. Nothing, Mr. Chairman.
CHAIRMAN:
Q. Nothing arising. Thank you, Mr. Delaney.
A. Thank you, Mr. Chairman.

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Q. Is this a good time for our break in the afternoon, while we're changing witnesses?
MR. ALTEEN:
Q. Probably would be. We can change a witness. Get to another witness. Have another little break, get to the third witness.
CHAIRMAN:
Q. Okay. Let's do that. We'll come back in 15 minutes.
(BREAK - 2:53 p.m.)
(RESUME - 3:10 P.M.)
CHAIRMAN:
Q. Okay, Mr. Alteen.
MR. ALTEEN:
Q. Thank you, Mr. Chairman.
CHAIRMAN:
Q. We got Mr. Collins?
MR. ALTEEN:
Q. Peter Collins.
MR. PETER COLLINS, SWORN
CHAIRMAN:
Q. Thank you. Be seated, please. Okay, Mr. Alteen.
MR. ALTEEN:
Q. Thank you, Mr. Chairman. Please state your

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name, your position, and the matters on which you'll be testifying today.
A. And good afternoon, Mr. Chairman, Commissioners. My name is Peter Collins. I'm the manager of information systems at Newfoundland Power. I will be testifying on the proposed $3.243 million in the information systems category of the 2005 Capital Budget application.
Q. In this proceeding, Mr. Collins, Newfoundland Power has filed in its principle submission materials relating to the information technology expenditure proposed for 2005, variances analysis and explanations for 2004, and in addition, they've responded to request for information from Board staff on information systems matters. Were these materials prepared under your direction?
A. Yes, they were.
Q. And do you adopt them today as your pre-filed evidence in this proceeding?
A. Yes, I do.
Q. Mr. Collins, could we start with a comment on your outlook for information technology for the next five years?

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A. Our strategy for investment in information technology for 2005 to 2009 remains unchanged since 1999. We will continue to invest in and use technology to improve customer service, operating efficiencies and reliability. We will accomplish this by focusing on getting more value from our existing technology investments. This will be done in two ways: number one, by upgrading or enhancing our existing software and applications; and secondly, by extending the life of our technology assets.
Q. Can you please give the Board an overview of how information technology is generally used within Newfoundland Power, Mr. Collins?
A. Technology allows us to offer our 220,000 customers more choices in how they interact with us, such as: through an automated voice response system or IVR; through electronic mail; through the internet website; or by choosing to speak to a live contact centre agent. Technology allows us to offer choices, to offer customers flexible choices in how they would like to be billed. They can choose options, such as: a 10 or 12-month equal

MR. COLLINS:

payment plan; automatic deduction payment plan; or electronic billing. These options would not be possible without the use of technology. In order for the company to be productive and efficient, technology allows us to manage large volumes of data that would be impossible to do manually. We must process large amounts of information on a daily, weekly and yearly basis. Applications, such as the Great Plains Financial system, allow us to capture, process and store large volumes of data very efficiently. The customer service system allows us to process millions of meter readings and bills each year.

Technology is also helping us to improve the reliability of the electrical system. At the system control centre on Topsail Road, the SCADA application monitors and controls much of the electrical system across the province. For monitored distribution and transmission lines, this application gives us immediate notification of outages on the electrical system, rather than wait for a customer call. Using SCADA's remote control capability, we

can cost effectively respond to trouble on the electrical system and minimize outage durations for customers.

Overall, our use of technology at Newfoundland Power has three focuses. We want to improve upon the service we provide to our customers. We want to become more productive by improving our operating efficiency and we want to improve our electrical system reliability.

Q. Can you provide the Commissioners with an overview of the categories of projects that are found in the information systems budget, Mr. Collins?

A. Yes. At this time, I would ask Colleen to bring up Schedule B, page eight of 73, please. Information technology, by its very nature, is often difficult to comprehend. Let me explain what I mean by the various project categories that you see before you on the screen. To do this, I'll use an example of a customer being served by an employee in our Corner Brook office, and how technology comes into play. We use a network to connect our offices across the province. This network is used for such

things as sharing information between employees, updating customer information, and monitoring the status of the electrical system. The Corner Brook office is connected to the St. John's office by the network. Network components are budgeted for in the network infrastructure line item that you see on the screen. On the employee's desk in Corner Brook is a personal computer. These personal computers are budgeted in the personal computer infrastructure category that you see on the screen. On the employee's personal computer, there are applications, such as the customer service system, that the employee uses every day to perform his work duties.

To serve the customer, the employee in Corner Brook looks up the customer's account information. This customer information is stored on a shared server in St. John's and sent over the network to the employee's personal computer in Corner Brook. The shared servers that centrally store data, such as customer data, are budgeted for in the shared server infrastructure line item that you see

on the screen. It's the last project on the screen.

Continuing on with this example then, the customer wants to sign up for electronic billing or e-bills. E-bills allow customers to receive their bills in their e-mail, rather than receive a printed bill in the mail. Last year we improved or enhanced our customer service system application in order to be able to provide this service to our customers. This is the type of project that can be found in the application enhancements category, which is the first project on the screen. Application enhancements in general are all about making improvements to customer service and operating efficiency. In fact, e-bills is an example of both improvements to customer service and improving our operating efficiency.

In order for us to be able to make such enhancements to our systems, we need to be able to test changes that we are making to applications such as the customer service system. We use test and development software to write enhancements and test how they will

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MR. COLLINS:

work for customers before we make them available to customers. This is important because I don't want any changes that we make to cause something else to fail. I cannot risk interrupting service to customers. The software necessary for this testing is an example of what is included in the application environment line item, which is the second project on the screen. This line item also includes upgrades that we must make to our software to maintain support from suppliers, such as Microsoft and Oracle. This means that if we have a problem with software, such as our internet website, for example, we will be able to call the supplier to help us to quickly correct the problem.

The customer systems replacement line item on the screen refers to our customer service system. I give it special attention here because it is our biggest and most complex application. This line item will contain projects to manage the risk associated with this aging application.

Q. Can you give us some specifics about the

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information systems projects that are actually proposed in this 2005 Capital Budget, Mr. Collins?

A. There are six projects in the information systems category, totalling $3.243 million or approximately seven percent of the total proposed 2005 Capital Budget. These projects are reflective of our strategy for investment in technology. This total of $3.243 million is the lowest capital budget for information systems since 1997 and is 20 percent lower than the 2004 forecast.

The first project on the screen, the application enhancement project, is required to make further improvements to existing applications. There are over 30 applications in use throughout the company. This project totals $1,087,000. Some examples of applications we are improving in 2005 are the customer service system, the Great Plains financial system, and the SCADA system. As well, in 2005, we will be improving the asset management system to provide efficiencies around the planning, scheduling, completion and efficiency follow up in the inspection of

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our 110 transmission lines.

The next project on the screen is the application environment project. Investment in the application environment is necessary to upgrade outdated software and to ensure our applications are working properly. This project totals $710,000. This amount is about what we spend each year to keep our technology environment up to date. In 2005, for example, we are upgrading key software used by customer contact centre agents to respond to customer requests. The supplier will not be supporting this software beyond February of 2005. Upgrading this software will ensure that these software products will continue to be supported by the supplier.

The next project is the customer systems replacement project. As outlined in the customer service system study that we filed with the Board last year as part of the 2004 Capital Budget application, the obsolescence of Open VMS is an ongoing issue that we are monitoring. As the operating system, Open VMS plays a vital role in making sure the customer service system is available to serve

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customers. That is, the customer service system will not work without Open VMS. The customer service system is our biggest application and is our primary system for serving customers. In the study, it stated that while industry support for Open VMS continues to decline, the supplier, Hewlett Packard, is committed to supporting it until 2011. The potential replacement costs of a new customer service system is estimated to be 10 to $15 million.

Therefore, over the next several years, I will be doing two things with regard to this important application. I will look for ways to extend the life of this 13-year-old system for as long as possible. By extending the life of this system, we are saving approximately a million dollars for customers for every year we can defer its replacement. I will also look for ways to reduce our reliance on Open VMS over the next several years. By reducing the size and complexity of the existing customer service system, the replacement cost of a new system will be reduced.

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MR. COLLINS:

The customer systems replacement project, totalling $144,000, will allow us to reduce our reliance on the Open VMS operating system and improve operating efficiencies. We will continue to monitor industry developments in this area to ensure that the risk to customer service and the company are being managed appropriately.

The fourth project on the screen is the network infrastructure project. This will allow us to make improvements to the company's network. This project totals $276,000. As I described earlier, the network allows employees and customers to access information from applications, such as the customer service system. In 2005, a significant project in this category is the replacement of the network switch in the system control centre at Topsail Road for $129,000. Through this network switch, the system control centre is connected to the St. John's Regional Office at Duffy Place and to head office on Kenmount Road, as well as several offices across the province. It is a key link on our

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communications network.

The next project, the personal computer infrastructure project, is required to allow the company to keep its personal computers and associated technology from becoming obsolete. This project totals $455,000. There are essentially two groups of employees at Newfoundland Power. One group has high personal computer capacity requirements and one group has low personal computer capacity requirements. Employees with high capacity requirements will receive a new personal computer. Their old personal computers are reassigned or cascaded to employees with low capacity requirements. This extends the useful life of our personal computers and minimizes costs.

We have been constantly improving the way we manage personal computers. In recent years, the company has increased their useful life. For 2005, the desktop computers to be replaced will be over five years old, although laptop computers will be four years old. In 2005, we will be replacing just under 20 percent of the company's personal computers.

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The last project is the shared server infrastructure project. This project is required to allow the company to keep its shared servers from becoming obsolete. The shared server infrastructure project totals $571,000. In 2005, we will be replacing five servers that have reached the end of their useful lives. Shared servers generally have a useful life of about five years. The five servers I am replacing in 2005 average over seven years old. Like personal computers, this is another case where I am exceeding industry averages on the life of our equipment.

As well, this project will focus on improving the security of customer and company information. Security concerns range from the malicious, such as viruses and hacking, to the accidental, such as system crashes due to hardware failures, software bugs and even fires. Securing the company's customer data from these threats is critical to maintaining current levels of operating efficiencies and customer service.

Q. Do you have any concluding remarks, Mr.

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Collins?

A. Yes. The information systems projects that you see on the screen reflect our overall approach of getting more value from existing investments. Sometimes this takes the form of upgrading and enhancing our existing technology and sometimes it takes the form of extending the lives of our technology assets. By recent historical standards, this is a low budget for information systems. Our need to invest in technology is not as great next year, in part because we are getting more value from our existing technology through upgrades and enhancements, and we are extending the useful lives of the technology for as long as we can.

In summary, Mr. Chairman and Commissioners, this budget is least cost and is directed at improving customer service, operational efficiencies and reliability. Thank you.

Q. That concludes the witness' testimony in direct, Mr. Chairman. He's available for cross-examination.

CHAIRMAN:

Q. Thank you, Mr. Alteen. Mr. Kennedy.
MR. KENNEDY:
Q. Thank you, Chair. Mr. Collins, I wonder if we could just look at the issue of the calculation of the impact of the productivity efficiencies that you've forecasted as being the result of some of your IT-related projects, and we can start, I suppose, with PUB 22.2. And this related to your capital budget category of application enhancements, 1 million 87 in total, and the question asked was "provide details of the cost analysis associated with improvements to the line inspection systems" and that project cost was indicated to be $83,000 in your budget application. And if we could just go to the Attachment A, please. Okay. So, and you attempted to provide, I take it, a calculation on the net present value that supports the decision to make this purchase of technology related to your line inspections, correct?
A. Yes, that's correct.
Q. And if I'm reading this correctly, that the initial investment in this particular technology of $83,000 in 2005, over a five-

year life span, gives a present value of 11,125? Correct?
A. Yes, that's correct.
Q. Okay. And so, and the positive figure denotes a positive present value obviously. In other words, it's to the good of rate payers and, in turn, the company to spend this $83,000?
A. Yes, that's correct.
Q. And you're clearly writing down the software investment over a two-year period, according to your capital cost allowance, Column B, 50 percent in one year and 50 percent in the other year?
A. Yes.
Q. And then your chief source of operating efficiency gains for this project comes from labour? Is that correct?
A. Yes, that's correct.
Q. And if I'm reading it correctly, you're forecasting under this net present value that the investment of this $83,000 technology related to line inspections will result in 2006 saving $23,453 in labour costs?
A. Yes, that's correct.
Q. Okay. Now there were a number of RFIs that

were issued to Newfoundland Power in which it requested for you to first identify the projects in which the primary justification was operating expenditures, and then where the primary justification for the project related to operation--sorry, operating efficiencies, where the primary justification related to gains in operating efficiencies to provide a net present value to support that operating efficiency. Correct?
A. Yes, there were several RFIs on that.
Q. And for the benefit of the panel, I can give you the list of the RFIs that asked specifically for that information, and it was--they're all PUBs, 22.2, 22.6, 22.7, 23.2, 42.2, and 43.2, and I think that's all of them. I think that's all the projects. Now Chair, this is another spreadsheet of a sorts that I did up which tries to capture the information that's in those RFIs that I just provided the list for. Again, similarly to the previous one, I've provided counsel with a copy of this yesterday. Presumably he passed it along to Mr. Collins, but again, Mr. Collins hasn't had a great deal of time to be

able to do an analysis of this. So I think that's certainly something that could be taken into account. There's a copy for the witness. I don't imagine he has one right there in front of him. And one for the panel members. And if it's in order, we can call that Information No. 2, Chair.
MR. ALTEEN:
Q. Fine, Mr. Chairman.
(3:33 p.m.)
MR. KENNEDY:
Q. Now Mr. Collins, what I've done in this table was I took the information that you had in each of the net present value calculations, where they were provided, and I just added them together basically. So under application enhancements, you can see these are the projected labour savings per your net present value calculations relating to each of those projects, as identified in the RFI, and I just took two years, 2006 and 2007. In most of your net present values, you extrapolate that out to 2010, over your five-year period, with some sort of escalation clause in there for your wages. And you can see that for B-61

MR. KENNEDY:
application enhancements, in those projects that Newfoundland Power has indicated that the primary justification for the investment is to achieve operational efficiencies, it totals $206,301 in labour costs projected to be saved, according to your net present value calculation, in 2006 for that project category. And you can see then, when I do the same thing for application environment--I see my spelling hasn't improved--and CSS replacement, that the total annual labour savings for 2006, as identified by Newfoundland Power in support of these particular IT projects, it comes to 344,267.
A. Yes, that's correct.
Q. Okay, now, I took a--in order to try to do some rudimentary analysis here of taking approximate average salary per employee of $45,000, I understand that's probably on the low side, that was because I excluded the lawyers out of the equation.
MR. ALTEEN:
Q. Cheap shot, Mr. Chairman.
MR. KENNEDY:

Q. But I guess, be that as it may, whatever sort of range we're dealing with in, you can see-- ultimately what I'm trying to drive at here is that if you're indicating in your net present values that you are going to make these operational efficiencies showing up in labour savings, it should end up resulting, I would suggest, in a reduction in your FTEs by virtue of you being able to knock that labour component out of your system. And I wonder if you could first comment on that, whether that's a fair sort of assessment or analysis of what's taking place here?
A. I think the assessment is fair, but there's a couple of things going on, Mr. Kennedy, that I would like to explain to the Board.
Q. Sure.
A. Yes, when we look at the net present value analysis, especially when we have operating efficiencies coming out of technology projects, we'll sit down and certainly my staff with sit down with the department affected and we'll, you know, they are the ones that are coming up with--that department is the ones coming up with the labour savings,

so, you know, we'll--and I'll be involved in looking at, making sure that, you know, there's some reasonableness to what they're putting forward, in terms of what they hope to save. In some cases with these projects and, you know, our main one in particular and that's the CSS--sorry, the Customer Systems Replacement Project and I can give you a reference for that.
Q. B65 if you're looking for the -
A. Okay, B65, yes. That particular project, there will be an FTE savings beginning in 2006. The nature of that project, we're going to be reworking the way the customer service system overnight processing works, such that we may not, you know, we will not require a shift operator to work overnight. So there will be a FTE savings there. And essentially what will happen with that position would be, that person will actually go over to another department and displaces some temporary labour that's over there today that's helping out. So in a case like that, absolutely there would be an FTE savings for the company.
A lot of the other projects, you're not--

it's really bits and pieces of people, so it's not, you know, it's not as cut and dry as that customer systems replacement project I just talked about. And I'll use an example of that one as well. It's in my own shop, in the IS department we have a help desk with two people on it, and a help desk takes calls from all over the province, whether it has to do with, you know, PC networking or, you know, the computer won't turn on, monitor is blank, passwords need to be reset. So I also get calls, you know, unfortunately from across the island about the responsiveness of the help desk. Most people don't want to be leaving a voice mail. When they call the help desk, they're usually in some sort of difficulty with their computer and they want to talk to somebody right away to fix the problem. And so looking at that issue and not wanting to add another body to the help desk and go from two to three, we looked at our stats and the type of calls that were coming in and passwords were--the resetting of passwords were about 10 percent of our calls. So to justify password management software as part

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MR. COLLINS:
of the application environment project, B63, what I'm doing there is I'm taking the calls and I'm going to get those calls handled a different way through the purchase of some software. And what that will mean is that that frees up my help desk staff to be able to respond to other calls, so maybe get those calls that are constantly going to voice mail, that sort of thing. It allows them to be more responsive, creates some capacity. So that's generally the nature of both types of savings that are going on there, Mr. Kennedy.
Q. So if I'm gathering correctly then, it's both a case of potentially lowering existing labour costs or avoidance of incurring new labour costs?
A. Yes, absolutely.
Q. Okay. And in the first example, the lowering of existing labour costs that that may either show up in a reduction of your current FTE account or it may display some other cost for one department which allows you to shift employees to another?
A. Yes.

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Q. But ultimately that should have a reduction in the overall labour component of the company, correct, in order to support your net present value calculation?
A. Yes, absolutely.
Q. Okay. And Mr. Collins, I just wanted to get you to just make a quick comment on, sort of in keeping with, I think, some of what you are saying is 42.2, RFI. And this related to your application enhancement's budget and there were four net present values given for four different subprojects, contract management, fixed assets, bank rec and changes to the intranet and I notice that in the first three of those, contract management, fixed assets and bank rec, your net present value calculation is showing, I guess what I would suggest to be a fairly nominal figure, if I'm reading that correctly, in the case of, for instance, your contract management--oh, I'm sorry, if we could go to Attachment A, here we go, in this case, for instance, your contract management you're showing a total positive net present value over a five-year span of $239.00.

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A. Yes, that's correct.
Q. And then if we go to the next one, next page, oh I see, it's attachment B, beg your pardon, $188.00.
A. Yes, that's correct.
Q. And then the next one, bank reconciliation, Attachment C, $261.00.
A. Yes.
Q. And then finally changes to the intranet, which is your Attachment D, so a little more substantial?
A. Yes, $9,400.00.
Q. $9,434.00. Would you agree with me that in so far as the net present value numbers for these first three projects are nominal in nature that they are, for the net present value basis, on the line about whether they're actually going to generate a net present value for you at the end of five years. I mean, if your discount rate is a little off, if you don't obtain the labour savings that you hope to achieve, and that's pretty much it as far as the analysis goes for these, and if either one of those was to be impacted not like you were hoping, your net present value could

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easily go the other way?
A. Sure. I guess, Mr. Kennedy, when we were responding to the RFI associated with that attachment, 42.2, the question was asked what are the primary justifications and with those three projects in particular, the fixed assets, the contract management and the bank reconciliation, we had a difficult time answering that because the primary--there was several ways to justify that project. There was qualitative and quantitative ways, if I could put it that way. So, you know, we did--it was primarily, obviously operating efficiencies and that's why we've responded as we did. But what else we have going on here is that we expect these solutions or these software solutions to last longer than five years, so the net present value analysis goes up to five years, but we, you know, we really believe, you know, that they will last longer than five years. The other thing that we have going on is that because of the oversight that, you know, my group and I bring to the labour savings that the departments are being forward that they say they are going to get

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MR. COLLINS:
from this, we want to be very conservative in our estimates. So that's a very conservative net present value analysis, I guess, Mr. Kennedy.
Q. Okay, but if you were more aggressive in your net present value calculation, you would have been forecasting greater labour savings, principally?
A. Yes, principally, yes.
Q. And so then that would have effected that data, for instance that you see on Information No. 2, the sheet that I just handed out, which shows what your total labour savings would be for the company and what that should reflect in a reduction in FTEs or at the end of the day, a reduction in the company's overall labour costs, correct?
A. Yes, yes.
Q. Okay, I just wanted to switch to your personal computer infrastructure project, Mr. Collins. And specifically PUB-46.4 and I think something got lost in the translation between the question and the answer. The question was what are the specifications of the PCs and

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laptop computers currently being used by those individuals who would receive the replacement computers to be purchased in 2005? And the answer was the table below provides a summary of the specifications to the PCs that have to be replaced in 2005. And then it goes, the actual individuals who will receive the replacement computers to be purchased in 2005 are unlikely to be the same individuals currently using these units.
A. Right.
Q. Now the units that you list in your table there, they're the ones, if you will, to put it in the vernacular, are headed out the door when the new ones come in, correct?
A. That's correct.
Q. Okay. The question though asked, what are the specifications of the PCs that are currently being used by the individuals who are going to receive the new computers. And would you know that offhand?
A. No, the way we do that for budgeting purposes, Mr. Chairman and Commissioners, is we sit down at around an age and timeframe we're putting together our budget for the following year,

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and we look at our 600 or so PCs, we look at their age, their performance and that sort of thing, and you know, what don't do is we don't go around and look at--and interview every individual employee and go through every department, you know, in the May/June timeframe and say, okay, that person there will get a new one, you know, eleven months from now when the new one comes in the door, because it's very impractical to do that. So what we do is we'll use some judgment based on, you know, talking with the managers responsible for those departments. We'll look at some of our help desk calls to see what PCs have been troublesome. We'll look at things like, you know, how much warranty is left on the machines, you know, look at how much more useful life can we get out of these? And then what we'll do is when the machines come in the door, and typically, you know, we're saying 113, but we won't buy 113 right away in the new year, so we'll buy a little bit less than that because we don't want to over buy. So we'll buy a little bit less than that and we'll do the analysis at that point in time

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and make sure that, you know, the person that's getting that new computer at that time, is a person that really needs it. Because what could happen in that period of time between, I guess May and June timeframe of 2004 and when the PC actually goes on the desk the following March or April timeframe, is that person could go from a high capacity user, someone that really needs a powerful machine, to somebody that doesn't need a powerful machine or vice versa. So we want to make their analysis as close to the purchase time as possible.
Q. But ultimately what drives your decision about purchasing new computers? Is it the requirement of your power users to stay on top and have the greater functionality out of a computer or is it lowest tier computers not cutting the grade and need to be retired?
A. It's more the latter, the lower tier computers.
Q. Okay. And so insofar as your decision-making process, it's the specs, if you will, of these computers shown on the chart that drives more about your decision making about computers to

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MR. KENNEDY:
--how many computers to buy in a given year?
A. Not completely and the reason I say that is because the chart on the screen shows that we're going to be retiring 88 Dell OptiPlex GX 110 desktop PCs. But we have 139 of those in the company, so we're not retiring all of those because there are still some of those have useful life remaining, because there's some of our employees still getting value out of those. So we don't make the decision and say the cut off point is a certain class or a certain speed of PC. It does come down to some analysis.
Q. So, Mr. Collins, when you buy a new computer, when the company buys a new computer, do you typically buy an entire computer, in other words, the tower, the monitor, the mouse, the keyboard, everything is bought, or do you just buy new towers?
A. No, we buy the unit, the whole unit, being the monitor, the keyboard, the mouse and the CPU, the tower.
Q. Okay, so I guess question No. 1 then is has the company explored, just in the case of

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needing to, if it needs to upgrade its computers, just buying new towers instead of buying the entire--presumably you already have a monitor, you already have a mouse and keyboard that you could just replace the tower, couldn't you?
A. I guess technically you can, you can just replace the tower, but you know, we feel it's not the least cost way of managing our 600 personal computers. If what you have there is a computer monitor that's essentially been on, in many cases, 24 hours a day, 7 days a week, for 365 days a year. Unfortunately a lot of people, you know, don't turn off their PCs. They just let them, you know, I guess go into standby mode or what have you, but we feel that, you know, we're managing the life cycle of the whole unit and replacing the whole unit. And what we find from our suppliers as well when we go out to tender for these things is that they package it such that they make it inviting for you, from a cost perspective, to buy the whole kit together, so to speak, so the mouse, the keyboard and that sort of thing.

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Q. Have you ever conducted an analysis of that issue just to see or support the decision to replace the whole unit as opposed to just the tower, for instance?
A. Other than, you know, our technical people would get together and talk about our options, Mr. Kennedy, but other than that, there wouldn't be any report or anything like that that we would have done.
Q. And similar to that, what about, like for instance in the case of the Dell OptiPlexers, would an upgrade of the ram that's there for the computer address the obsolescence issue with that computer and allow you to defer buying an entirely new computer for a year or two years?
A. When you look at what it would cost to actually go out and crack the covers open, I guess, so to speak of the 88 machines that are out there, that would be a significant operating cost to go out and take a PC off someone's desk for, you know, the couple of hours that it would take to put more memory and that sort of thing, that's one side of it. It would cost a lot of money to do that

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because also the employee doesn't have a PC for that period of time that you've got the cover open. And, you know, my experience with computers in general, I guess, because I've been around them for close to twenty years, is that you don't want to be cracking the covers open on these things. You could void warranties, number one, and you don't want to be getting in there and jarring something loose, you know. The best thing that could happen to a PC is that when it goes on a desk, you know, it stays in that position, that's just the nature of that equipment.
Q. I was kind of curious, though, Mr. Collins, most computers that you buy have additional memory slots built right into them, don't they, with the plan for your--with the ability then for you to be able to upgrade the ram, to void obsolescence?
A. I don't -
Q. You don't break any warranties by opening up a tower and installing additional ram.
A. Well, if our employees open up the tower, if we're not certified to do that, we would void our warranty and our service agreement, I

MR. COLLINS:
guess, with the company. So on the issue of are there memory slots available? I can't make that assumption because when we spec these machines for purchase, we want to make sure that we're going to get as long a life out of these things as possible without all of that cracking the case open, that sort of thing. So we'll put enough memory in there that we're sure that five years from now, or longer, it will have sufficient memory and disc space for what we need.
Q. Your policy of cascading your computers, has the company examined or conducted any analysis of the cost difference between a cascade policy and a policy that would involve spot replacements of computers, and do you know what I mean by "spot replacements"?
A. I'm not quite sure what you mean there.
Q. Well your cascade process is, I understand it's almost a moving down from tier to tier, so that if you've got 100 new computers being purchased in 2005, virtually almost everyone in the company gets a new computer or is it only spot -

A. Well, those 100 computers that we would buy in 2005, they will go to people that we've identified need that extra processing capability that would come with a new computer.
Q. Okay, so you don't have a shuffling down between all the different tiers of your company of everyone gets bumped off the computer they have and they get the next hand-me-down from the person above them?
A. No, I don't think that would be cost effective either. There's a balancing act that goes on, you don't want, you know, if you're buying a computer, you don't want to be interrupting the same employee year after year, that sort of thing. You want to create some stability in their environment so that they are getting--they're being efficient in using that computer, rather than replacing it every year.
Q. That's all the questions I have for Mr. Collins, Chair. Thank you. Thank you, Mr. Collins.
CHAIRMAN:
Q. Mr. Alteen? No?
MR. ALTEEN:

Q. Nothing Mr. Chair.
CHAIRMAN:
Q. Commissioner Vincent?
COMMISSIONER VINCENT:
Q. Yes, I just have one question relative to, I guess, have you ever considered leasing computers verses purchasing and really dumping them out the back end after a period of time? Have you looked at that?
A. When we look at that, what we find is that the suppliers, like Compaq or HP, I guess, IBM, they want you to get rid of them after three years--even four years, I think they have actually gone to four years now, but for us, you know, they last longer than that period of time. So, you know, there's no--I don't see any benefit--and we haven't seen any benefit in really just doing a complete Evergreen, it's called actually, a complete Evergreen of getting rid of all of your computers after three or four years. I think the whole cascading approach that we do in that regard is the least cost way. And before we'll be buying, you know, a bunch of computers, we'll make sure and we'll talk to the finance

department and understand, I guess, the issues around what if, you know, we lease them this year verses, you know, pay for them and what are the issues there, so -
Q. You've considered it, yeah, okay. Thank you.
A. We've considered it, yeah. Okay.
CHAIRMAN:
Q. I have no questions either. Thank you, Mr. Collins. Now then, Mr. Alteen, where are we?
MR. ALTEEN:
Q. I am ready to call my next witness, Mr. Chairman and hopefully we'll be finished in, I would expect all the evidence within the hour, a short break and we can go to argument. I think my learned friend and I can get this argued in a very expeditious manner this evening. We might be here until 5:30 or 5:45 though, if it pleases the Board.
CHAIRMAN:
Q. That presents a problem. I wasn't aware that this morning it would present a problem, but it presents a problem to us now because I understand one of the Commissioners has a problem with going beyond 4:30 and that's, I guess, leaving now that we can go one of two

ways: we can sit until 4:30 and hear your witness and get as far as we can by that time, or we can break now and come back in the morning at 9:30.

MR. ALTEEN:

Q. I'm at the pleasure of the Board, Mr. Chairman and I'm ready to go now. It might take a little longer to seat the witness and get to it, it's a bit dense talking about pensions, so it may take a half hour to get through it and we regret the subject matter, but there's not much you can do with it.

CHAIRMAN:

Q. Probably better to start it fresh in the morning.

MR. ALTEEN:

Q. Then we're at your pleasure on that, Mr. Chairman.

CHAIRMAN:

Q. Well that's what we will do. So we'll break and come back at 9:30 in the morning.

MR. ALTEEN:

Q. Thank you.

Upon conclusion at 4:00 p.m.

CERTIFICATE

I, Judy Moss Lauzon, hereby certify that the foregoing is a true and correct transcript of a hearing into Newfoundland Power's 2005 Capital Budget Application, heard on the 20th day of September, A.D., 2004 at the Public Utilities Board, Prince Charles Building, St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 20th day of September, A.D., 2004

Judy Moss Lauzon