LIST OF UNDERTAKINGS

(9:07 a.m.)

CHAIRMAN:

Q. Good morning. Thank you. Seems like a pretty decent day out there for an election. Could prove to be interesting, I'm sure, before it's all over. Good morning, Ms. Newman, are there any preliminary matters before we begin?

MS. NEWMAN:

Q. Good morning, Chair. No, there are no preliminary matters I'm aware of.

CHAIRMAN:

Q. Thank you. Good morning, Mr. Haynes. Mr. Kelly, when you're ready, please.

KELLY, Q.C.:

Q. Thank you, good morning, Chair. Mr. Haynes, good morning.

A. Morning.

Q. When we broke yesterday we had looked at some of the system characteristics and how Hydro goes about planning for future generation and we had also looked at where the various thermal units and other small units around the island fit into that structure. And I want to take you next along that same line to the report filed by the Industrial Customers by

Intergroup Consultants, Mr. Bowman and Osler. I want to take you to page 10 of that report at line 3.

A. Yes.

Q. Do you have that?

A. Yes.

Q. Beginning at line 3, the authors write, "In other words, the current 2004 test year generation and transmission complement and the 2004 test year revenue requirement reflects a plant in service that is in excess of what is considered by Hydro to be required to properly service the 2004 loads." And I'd like to ask you, as the Production Vice-President, as to whether you agree that the plant in service is in excess of what you consider is required to service the loads?

A. No, I don't think what we have in service is in excess of what's required to meet the loads given our criteria that we operate by.

Q. And let's take that in a number of pieces now. As you add generation capacity to the system, take, for example, Granite Canal--that usually--well, it always comes in in block increments, doesn't it. There isn't some

ability to simply magically have it added on a straight line every year.

A. No, that's correct.

Q. And in fact, Mr. Brockman talked about it in his evidence as being lumping. So through the entire plan cycle you go through essentially cycles of forecasting and energy shortfall or capacity shortfall, then figuring out what plant is building that plant until then a new forecast indicates that a plant is then required again in another number of years. So you go through these cycles of building?

A. Yes, that's correct.

Q. Now, if we look at your table 8 again -

A. Yes. If we could get Mr. O'Reilly to -

MR. KENNEDY:

Q. Page 37, Mr. O'Reilly.

KELLY, Q.C.:

Q. If we look at that, even in 2004, as we talked about yesterday, you still have a loss of load hours on your probabilistic model of 1.1 hours.

A. Yes.

Q. And so these plants that we've talked about are not excess because they're required to

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KELLY, Q.C.:
meet that capacity as may be necessary from time to time.
A. That's correct.
Q. Now, can I take you to page 28 of the Osler document at line 7. And at line 7 the authors write, "The current situation allows for a serious review of the island interconnected generating plant in service, what role each unit plays in providing the system with appropriate levels of reliability and whether a portion of the generating complement in fact is not required for service to the entire grid as opposed to perhaps being simply of local benefit to radial loads for the purpose of voltage control supply during outages, etcetera." Can I get you to comment on the desirability or appropriateness of reviewing in kind of little time blocks whether a particular piece of plant is important or whether it's needed to look across a longer time frame. Just explain that to the Board.
A. I guess when you plan new generation, as you mentioned, or implied, that you don't actually build a megawatt when you need a megawatt.

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You evaluate the LOLH criteria that we'll review. And basically the 2.8 hours per year kind of equates--it does equate to approximately 16 percent reserve. And when you build a new plant, you don't build to meet specifically 16 percent reserve, it's the function of the economics of the alternatives that are available. And in 2004 we're up, you know, approximately 20 percent reserve. And basically we will, as the load increases over time, that will come down to a 16 percent or--and the 16 percent may change, that's not a concrete number, depending on the load factor and so on. And then that will trigger new generation sources to be required. So you just can't build a plant and then exclude a bunch of small generation that is still used and useful to the system.
Q. And that would be true for all the type of the plants we talked about yesterday, whether Great Northern Peninsula, Burin Peninsula, or out in Wesleyville?
A. Yes, that is correct. And I guess in Wesleyville that would be a Newfoundland Power plant but it all helps the overall island,

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interconnected load, whether it's Newfoundland Hydro's generation or load or Newfoundland Power's or the Industrial Customers. It's a benefit to all customers.
Q. I'd like to go to a related matter next and this is the generation credit for Newfoundland Power. I don't want to get bogged down in cost-of-service discussion with you but how this works in principle. Can I take you to NP-215 as a starting point.
A. Yes.
Q. And the answer in 215 talks about the purpose of the generation credit, to provide a credit that represents the capacity value that NP's generation brings to the island interconnected system with respect to system planning and operations from which all customers benefit, and is credited as being consistently accepted since '77. I'd like to go through with you how that works now in practice. As I understand it, first of all, Newfoundland Power provides Hydro with its forecast peak requirements for your planning purposes?
A. That's correct.
Q. And that forecast is the full forecast first

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of all before you take off any generation credits. In other words, you get the full native load forecast.
A. For the island planning purposes that would be the appropriate number, yes.
Q. And if we go to Schedule 2 of your evidence and we look at the various Newfoundland Power generation assets there, we have down towards the bottom, we have the hydro electric at 93.2 and the thermal at 54.2. And those are net capacity numbers as we talked about yesterday, so before we get to any kind of reserves, reserved capacity that you touched on yesterday we're going to come back to.
A. Yes, that's correct.
Q. In other words that's just the rated capacity less the station service.
A. Yes, the net generating plant capability.
Q. Exactly, okay. So one possibility is if Newfoundland Power wanted to reduce peak, they could run all of those plants any time they got to a peak situation. But that would be inefficient for the system overall, wouldn't it?
A. Not necessarily but I guess over peak it

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MR. HAYNES:
likely would be, depending on how they planned the system.
Q. Let's talk about--take the thermal, for example. If you have water or number six fuel capability at Holyrood available on the system, it wouldn't make sense for the total cost of the system for Newfoundland Power to be running the Wesleyville gas turbine, because it's more expensive power. Agree with that?
A. Not if Holyrood has the ability to generate more power. If it's maxed out, then it may be gas turbines or diesels or whatever is required over that particular peak.
Q. Right. So that -
A. There's not a pat answer, I don't think.
Q. No. But in the usual case, leaving aside these peaks where there's no more capability in Hydro's system, it would not make sense, for example, to run Wesleyville as long as you can provide the power from Bay d'Espoir or Granite Canal or Holyrood. We agree on that?
A. Given that it's available elsewhere, that's correct.

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Q. Because we want to have least cost power. So Newfoundland Power only runs those thermal stations in really two situations; number one, if Hydro calls upon it to meet overall system peak, or if we have a problem, for example, with a feeder line out to Wesleyville, a power outage situation. You agree with that?
A. Yes.
Q. Now, let's look next at this reserve percentage. And if we start--let's go to your JRH No. 3 Exhibit at page 14 where there's a discussion of that.
A. Page 14?
Q. Yes, page 14. And just explain to the Board, it begins there under "System Operation", it requires approximately 16 percent or 300 megawatts of reserved capacity to meet the planning criteria. Can I get you to elaborate on how that--what that means and if you could explain that to the Board and as you come to this you can also look at IC-293 which provides some helpful information.
(9:20 a.m.)
A. I guess we undertook a review, I guess, of the LOLH to determine what that means with respect

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to reserve. And I guess at one point in time we were at 18 percent and I guess--and there are several things that affect that; the load factor, the daily load shape and so on. And that particular review resulted in that the 2.8 hours per year basically is approximately 16 percent reserve requirements with basically 300 megawatts of capacity, most of it, or a lot of it is peaking capacity that's available to help us get over that maximum predicted peak that we would see.
Q. Okay. And if we go to IC-293, can we just put that up on the screen? Can you explain there how that 2.8 hours ties into the 16 percent down at lines 13 through 15?
A. Yes.
Q. Anything else you need to add to that or is that sufficient?
A. Well that's is. There is--the report that actually does that is included in IC-158 if there was other clarification required. But the, you know, the actual deliberation or determination of the 16 percent -
Q. Now, just go over to IC-294, the next--and we looked at the first part of this yesterday.

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This talks about where the reserve capacity fits into the operating sequence in effect. If I take you down to lines 19 through 22 -
A. Yes.
Q. Just explain how that reserve capacity issue bears upon how you bring these units online and how they're operated.
A. There was some discussion yesterday regarding the loading of the units. The operator in the control centre has to keep ahead of the load growth, the--not the load growth on a long-term basis, but on a daily load. For instance, units come on in the mornings when people get up and start to increase the demands on electrical energy. They start in the evening as well when people go home. So the operator has to stay ahead of it. He has to turn the units on. As well, we're not interconnected to the mainland grid so there's a frequency regulation component which they have to pay attention to. And you don't turn on a machine and turn it up to the pins, as I'll say. You don't turn it up on the maximum output, it has nowhere to go. If the machine has nowhere to go, in a sense you can't open

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MR. HAYNES:
the wicket gates more, you can't open the steam valve more, it cannot contribute to frequency regulation when the load goes up. It can contribute when the load goes down a little bit, but it's not a recommended place to be because the governors and so on usually need a little bit of latitude for chasing the frequency. They all move a little bit, some units more than others. So the operator, when he is dispatching loads, has to keep his eye to that. He has to maintain a reserve to look after if we lose a machine, sudden load pick up or sudden load loss. So you just don't turn the machines on to their maximum capability and then when you hit the pins, turn on another machine. You cannot operate a system that way.

Q. Okay. Now, and the last part of this answer, lines 20 through 22 talk about the fact of therefore what you do is you bring Holyrood up to full capacity or capacity with some reserve left and then control the frequency or the reserve with the hydraulic unit?

A. By and large, yes.

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Q. Now, we're talking about the generation credit for Newfoundland Power and we looked at Schedule 2 which gave us the net capacity of Newfoundland Power's generation, but that full capacity is not used for the purpose in the generation credit, you take out this reserve component as well, first, don't you?

A. The 16 percent is adjusted.

Q. Let's just go to have a look at that at IC-306. And if we scroll down to the table at the bottom, you can just explain the capacity credit and how this works.

A. Well, I guess on the revision, the Newfoundland Power coincident of peak is 1,084 megawatts. And then it's also included in that then to be considered how much generation they have online at the time, which is considered to be 77-1/2 megawatts. So their native load; i.e., the total load that Newfoundland Power is serving is 1,161-1/2 megawatts. And the expectation for Newfoundland Hydro is that we would provide in a normal situation, 1,084 megawatts. And the capacity credit, which is 94.6 megawatts, which you would also see in Schedule 2 is

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actually divided by the 1.16 to give them the--you know, they're giving credit on the same basis of the 16 percent reserve requirements.

Q. So we get, the credit that we get takes off 16 percent just like you needed it, across the whole system, correct?

A. That number is used across the system, yes.

Q. And so the credit for the hydraulic is the 81,000 kilowatts or 81 megawatts and for the others, 37 and 6.

A. That's correct.

Q. Correct. Okay. And so the demand use for the cost-of-service allocation purposes, if we take the Newfoundland Power's forecast native demand, the peak demand and then we less the generation credit off of that, correct?

A. Yes.

Q. Now, as we saw in NP-215, the generation credit, that process has been used consistently since 1977?

A. As I said, there were different reserve factors done as time changes, as load factor changes, but that's correct.

Q. But the principle has been consistently applied.

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A. The principle has been consistently applied.

Q. Now I provided a hand-out which is from the February '93 Hydro cost-of-service methodology. I just want to have a quick look at that.

MS. NEWMAN:
Q. That will be information item No. 13.

KELLY, Q.C.:
Q. 13, thank you. And this question of the generation credit was looked at at that point in time and page four gives the various expert witnesses who testify that and we'll take you through that. But if you come over to page 50, the issue in '93 was whether the mobile gas turbine at Port aux Basques was to be included for purposes of that generation credit, because the issue was it was mobile. And the Board concluded that because it is essentially tied into the system the bulk of the time and available to provide power, that it was appropriate to include that as part of the generation credit.

A. Yes.

Q. And that's one of the plants that we talked about that is still in place that still

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KELLY, Q.C.:
provides this assistance to your LOLH planning criteria we talked about earlier?
A. That's correct.
Q. And the Board reiterated its position on the generation credit in the P.U.7 and I won't take you back through that in any detail. Can I take you to Mr. Osler and Mr. Bowman for a moment at Section 6.3 which is on the bottom of page 28. And it begins at about line 20-- we'll start at 24, or 25. "However, given the current situation of excess capacity until 2011, three matters merit review", they suggest. One is the allocation of the GNP generation, as common. Two is Burin Peninsula. Mr. O'Reilly, if could just scroll over to the next page. Three is the provision to NP of the generation credit. So they tie in the generation credit to this question of excess capacity. Now, we've agreed, I take it, Mr. Haynes, that there is no excess capacity in the system in your view?
A. There is no excess capacity in the system to meet our planning criteria of 2.8 hours per year.

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Q. And so would you also agree with me that in terms of excess capacity, it is inappropriate to review the question of the generation credit calculation just as it is, for example, inappropriate to review the use of the generating facilities on the Great Northern Peninsula that belong to Hydro.
A. I think the approach that's been proposed by Hydro is consistent in the application of all these generation sources.
(9:30 a.m.)
Q. Now let's turn next then to have a look at the question of the transmission line assignment. And I wanted to talk with you about the Burin line, in particular. Let's start by going to JRH No. 3 and we'll start with page 6 which has got, I believe, a plan. There we go--or a map. Can we scroll up a little bit more, Mr. O'Reilly, so we can get the Burin Peninsula in down there. Can you blow up the Burin part of it a bit, because that's what we really need to focus on. There we go.
Now, perhaps we can just have a look, first of all, Mr. Haynes, and you can explain where these lines are when we look at who is

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served with these lines? Can you just walk us through that?
A. I guess the 138 kV line serving the Burin Peninsula ultimately terminate on the main grid at Sunnyside. TL-212 is from Sunnyside to Monkstown and there's a spur line to Paradise River which is a Hydro owned generating plant of eight megawatts. That lines continues on to Linton, eventually to Linton Lake and there's also another 138 kV line that goes from Sunnyside to Salt Pond. And on the foot of the peninsula, it connects the Green Hill gas turbine, the three plants of Newfoundland and Labrador Hydro and assuming that we do conclude on the wind contract, we'll include a 25 megawatt wind generating site at St. Lawrence, in that area. So there's a significant generation on the Burin Peninsula.
Q. And the wind generation site, Lawn is shown there and that's approximately about where the wind generation site is going, down that Lawn, St. Lawrence area?
A. I gather it's not too far from St. Lawrence, yes.

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Q. Now, the TL-212 line, there are a number of Hydro rural customers along that line near Paradise River and the Linton Lake area?
A. Yes, Petit Forte and there's a couple of isolated areas which were served by -
Q. Okay.
A. (Unintelligible) system.
Q. And from--these lines, 219 and 212, these ultimately tie together with a loop down around through Green Hill and the bottom, which would be a Newfoundland Power line?
A. Yes, I believe those lines are 66 kV in the loop.
Q. Right. So, if, for example, we took the TL-212 line and that was out of service for some reason, either because of a transmission outage problem or because the line was out for maintenance, you're replacing insulators or line or whatever, then the other line services the load and vice versa?
A. That's correct.
Q. And you talked about the problem that you have up in Goose Bay where you have only one line so that the two-line system enables one line to be taken out for maintenance from time to

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KELLY, Q.C.:
time?
A. That's correct.
Q. Have a look at page 18 of your JRH No. 3 for a second. And I'd like to get you to explain to the Board this transmission allocation guideline that you set out there and why you're proposing that as a reasonable guideline.
A. I guess there are several different considerations in allocating, or our proposed allocation of transmission cost. You know, we've been serving two customers. I guess the guidelines were, it would be common plant, if it serves generation and transmission--I'm sorry, generation and so on, it's common plant. But there are a lot of considerations, you know, the size, the substantial benefits to more than one customer and so on. So in the whole, we have proposed that the Burin Peninsula, because it serves two customers, because it has significant generation and significant generation I think is the key, that it should be considered common. In the Port aux Basques area, the generation is

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similar to GNP. It's not as significant or a bigger factor from the point of view of the local transmission, but it's still an aid to the overall system, still benefits all customers in meeting our 2.8 hours per year criteria.
Q. And as we looked at the table that's in the report, we don't need to go back to it now, but there is in total, some 34.7 megawatts of generating capability already down on the Burin Peninsula?
A. Yes. And the possibility of 25 more in the near future.
Q. I want to just take you to that point at--let's just go to NP-219. And this talks about that 25 megawatts of wind power. And that, I take it, is a significant increase in the capacity so it would now give us almost 59.7 down there.
A. That's correct, but I guess our recommendation--Hydro's recommendation is with or without the 25 megawatts, that the 34.7 is still substantial enough to consider to be a common -
Q. Yes and I don't quarrel with you with that but

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I want to give the Board some sense of the order of magnitude both with and without. And if we just have a look at IC-339, for a moment, the peak demand down on the Burin Peninsula in 2002 which--that would only, I take it, happen during the winter period, with only 58.7 megawatts in total?
A. Yes.
Q. So, during a good part of the year the capacity down there and certainly with the wind when it comes on stream, the wind plant in particular, will in fact provide generation capability to the whole system, would it not, Mr. Haynes, including customers off the Burin Peninsula?
A. That's correct and consistent, consistent with our proposed -
Q. Right. And so, would you agree with me that the Burin facilities and the transmission lines actually service three groups of customers at least. Number one, the Hydro rural; number two, the Newfoundland Power or common ones, and also the Industrial Customers by providing that capacity off the Burin--of assistance to them.

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A. Yes, that's correct.
Q. Now, I'd like to turn next and have a look at number six fuel if I could. Kind of change gears a little bit here. And I'd like to start with--on this topic with Schedule 7 of your evidence.
A. Yes.
Q. And as I understand from the first line there, the fuel expense which is--this is the number six fuel that we're talking about that your forecasting for 2004 is 84.4 million dollars? Scroll across to--as you go across--there, Mr. O'Reilly has got his -
A. Yes.
Q. Now, I just want to try to understand that a little bit first. The way that you kind of work through this is we take the forecast energy generation, take out what you can produce with your hydraulic, that then gives you what you're going to require for out of Holyrood. And, as I understand it, from this particular table, you need 1,790 gigawatt hours out of Holyrood. Is that essentially correct?
A. Yes, there are a few other considerations but

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MR. HAYNES:
that is the major driver.
Q. That's the gist of it. And then you've got that many gigawatts to get out of Holyrood and you use a fuel conversion factor of 624 for each barrel, and you determine from that, that you need 2,868,830 barrels of oil, have I got that much right?
A. That's correct.
Q. And just by way of curiosity, more than anything else, how big is a barrel in litres or gallons?
A. 42 US, 42 gallons.
Q. 42 US gallons?
A. I believe it's US gallons.
Q. And not to digress on that point, the number of barrels, you then multiply by the fuel price forecast which you told us is $29.20, to get the amount of money that you need?
A. Yes.
Q. And when you do that Math, 2,868,830 times 29.20 you get 83.8 million dollars. 83 million 769, to be more exact. And what we were wondering about is you got a forecast of 84.4 and we're wondering where this other

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$600,000 comes from or goes to?
A. The average price at that time for 2004 was based on a single number, but we do consider the inventory going into the year so, you know, there's some impact at the inventory at the year end. So it wouldn't be strictly a straight Math, particularly when we use a single number for 2004, which is all what we had from PIRA at the time.
Q. If it's already in inventory, why wouldn't that be adjusted through the RSP?
A. Well, the inventory at the end of the year is--what we have established in the oil tanks is an average inventory price of whatever it happened to be. It would not, I don't think--the field inventory is not part of the RSP directly -
Q. There's roughly about $600,000 extra in that number over the $29.20 for existing inventory?
A. I'm not sure of the exact mechanics or the volume, but that's basically at the year end, there is an allowance for inventory costs at the time. There were RFIs answered to that effect and giving some flow charts.
Q. We were trying to understand how that worked.

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Okay. So the average kilowatt hour or the conversion factor depends on the generating efficiency of the plant, so that the higher the fuel conversion or efficiency, the lower the fuel cost over all?
A. The higher the overall efficiency of the plant, the higher kilowatt hours per barrel and that would reduce the actual cost of fuel.
Q. Now in 2002, the Board set it at 615, but Hydro actually achieved, as you show on your schedule here, 648, and if we go to IC-207, and we scroll down towards the bottom of that, that actually resulted in about a difference of $6 million in total of which 3.6 million, in fact, would have accrued to Hydro's benefit?
A. Yes, that's correct.
Q. Okay.
A. And if you go to Schedule 5, which shows the chart, I mean, 2002 was an exceptionally high production--a record production year for Holyrood, which would naturally, all things being equal, drive the efficiency factor up.
Q. Okay. And I take that point, but let's go through a couple of other factors first and

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then see if we can come back to that one. Can I take you to NP-74? Let's just see how we get these numbers first. At line 11 there, it indicates how you get the 624, if we could scroll up the table, Mr. O'Reilly, there you go. You took the average for 1996 through to 2002, correct?
A. Yes, that's the weighted average, yes.
Q. Okay. And so you've got production data from '96 all the way up to 2002, and why did you take 1996?
A. In 1996, we installed--we purchased and installed a program called Eta Pro at the Holyrood plant, which basically assists the operators in tweaking and maximizing the efficiency. It looks at many operating parameters in the plant to ensure that we stay up as high as we possibly can. The operator has a fair bit of control over internal plant stuff and the system operations people also, in the control centre, try to maximize the loading required of the plant.
Q. So there was an improvement in efficiency in 1995, so you looked at the data then from 1996 on?

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MR. HAYNES:

A. There were new tools installed, effective in 1996, that would aid the operator in achieving a higher number.

Q. Okay. And can I suggest to you that there have been some improvements in output efficiency since 1995, in other words, from 1996 on as well?

A. There were a couple of projects which would help ensure that we stay up to our proposed 624.

Q. Okay. Let's look at IC-252 for a moment, and there are three projects that are talked about there. The water lance installation, the reheater tubing on No. 3, and the Continuous Emissions Monitoring System, and perhaps we could start by having you--you say in line 14, one and two should be considered together. Could you just explain to the Board what one and two were all about?

(9:46 a.m.)

A. There are three boilers in Holyrood, obviously, one for each unit. The first two machines are tangentially fire boilers, which means the guns or the burners, if you will,

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are located in the corners of a square box on different elevations. No. 3 is a Babcock Wilcox boiler and basically it's front-fired. All the burners are on the front face of the boiler, and when it's firing, you tend to get build up on the back wall of the boiler, on the tubes. So what the water lance project did was basically install a device to go in there and inject the amounts of water to keep that area clean, you know, to reduce the build up of slag and so on, which basically impacts the amount of heat that can be transferred to the water wall. So that's what the water lance project was.

The reheater retubing project, which was completed a couple of years ago, or a year and a half ago, was based on--and this was discussed at one of the Capital hearings, the reheater in Unit No. 3, you try to control the temperature of the main steam and the reheat steam to about 1,000 degrees C, and there was great difficulty from day one in trying to match those numbers, and what we did, we basically retubed the reheater, either added tubing or removed tubing to try to balance

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that particular situation, and they're all on the same unit. That's the first two.

Q. Okay. Before you go on to the next one, when were those two projects on No. 3 unit completed?

A. I think they were completed in 2002, I believe they were actually finished.

Q. Right. So that improvement in efficiency would not be in the data from 1996 through to 2002? There might be some impact, but only in the year 2002? Would that be correct?

A. I don't recall if the water lance project was actually completed in 2001. That may have been a little bit earlier than the reheater, but there would not be certainly prior to 2000 any impacts of those changes.

Q. Right. And in 2002, as we've already seen, that's when you got 648 kilowatt hours per barrel in any event.

A. We suggest the biggest driving factor there was the fact that we had a very, very high average unit loading.

Q. Okay. But those two projects at No. 3 unit, as we come down to line 22, equates to a plant efficiency improvements, in other words

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overall at Holyrood, of two kilowatt hours per barrel?

A. That would be the calculated number based on assuming that Unit No. 3 generates one-third of the production. Actually, it's more like close to one and a half. Unit No. 3 overall is not the most efficient machine, so it's not the favoured machine, if you go down through, you know, a priority loading system. So it's actually that particular number of two kilowatts is based on equal loading of the machines. It's more like one and a half actually, if you calculate the number.

Q. For purposes of rounding here, call it two.

A. Or one.

Q. It's your number. Line 24, you then start, you then talk about the Continuous Emissions Monitoring Project. Perhaps we'll just get you to explain what that is next, first.

A. The Continuous Emissions Monitoring Project was approved in the 2001/2002 budget, our capital, and it'll be completed--well, it's just being completed now as we speak, calibration and so on. Basically, it's primary role is to monitor our emissions, our

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MR. HAYNES:
environmental emissions, to give us a better handle on exactly what we're ejecting into the environment, CO2, et cetera, et cetera, and it does provide feedback to the operator to allow him to control particularly the excess air or oxygen and so on to tweak the burning process. And it's anticipated, based on industry numbers, that it can contribute to up to a half percent increase, which of 600 kilowatt hours would be three.

Q. So that item in line 26 to 27 is anticipated to give you an improvement of about three kilowatt hours per barrel?

A. On its own, all things being equal, that would be what we would anticipate. We have not proved that actually as yet, but certainly we hope to achieve that.

Q. Okay. And that, of course, would not, because it's not yet in service, it's only going to come into service this fall, that is not reflected in any of the average numbers that we just looked at in NP-74, correct?

A. We consider, I guess, our proposal of 624 kilowatt hours per barrel, we consider these

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two or three items to assure of being able to meet 624. There are so many variables that affect the conversion factor at Holyrood, with unit fouling and the conditions that this will assist us in meeting that and as we built on that over time, we will change our average appropriately or propose it be changed appropriately.

Q. Just have a look at NP-207, and this is the experience for 2003 and for 2003 to the end of June, you are running 639 as your conversion factor?

A. Yes, that's correct, and we've had some lesser months since.

Q. Okay. Do you know what the current amount would be?

A. The actual calculation for the end of September is 636. There's been a deterioration.

Q. So 636 to the end of September?

A. That's correct.

Q. But that would account for Holyrood's slowest months of all, which would be June, July, August and September, would it not, when the load would be the least?

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A. Yes, that's correct.

Q. Okay. Now you talked about your loading graph and you could put up again, if you want, but we looked as we went through how the system operates, how you get Holyrood up to capacity less reserve first and then adjust the peak through the hydraulic units. We talked about that. So that having gotten these improvements in efficiency, can I suggest to you, Mr. Haynes, that because of the way you operate the system, these efficiency gains are able to be achieved by the way you load the system? Can I get you to comment on that?

A. Yes. Obviously our target is to maximize the energy conversion factor, but when you look at that particular graph, that there basically is five or six years of data and depending on the average loading that you see in any particular year, you will have a lot of those, the scatter points, you know, on the high end. Like at 140 megawatts, you'll obviously see that we--if we can stay up there continuously and start the machine and load it to 140, which is not practical, there are a lot of other system conditions. There are unit

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fouling issues between the condenser water temperature and, you know, heater performance, cooling water, condenser fouling, the amount of build up of ash and so on in the air preheaters all impact that number, and when you look at that particular chart, between 100 and 120 megawatts, basically 30 percent of our operating monthly averages are actually between 100 and 120 megawatt number, not up at the 140. In fact, it's less than ten percent of the time that we're actually on average unit loading in excess of 140 megawatts, which would drive the conversion factor, as you see it there, to between 625-620 number.

Q. But wouldn't that have been true now through the summer that we just came through, in 2003 at Holyrood, in other words, you would have been down in those lower load levels?

A. Well, not necessarily. When we're running the machines for voltage support, particularly on the shoulder months, it's usually at a lower loading. We wouldn't necessarily--we wouldn't actually burn oil or keep it at 140 megawatts if we didn't need to do it for hydraulic purposes, but we would keep it on for voltage

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MR. HAYNES:
support. We have to maintain some generation on the east coast, particularly in the shoulder months because of the load, and it's a major load area and there's very little generation here. So it's a very mixed bag of influencing factors between the hydrology system, the voltage conditions on the system, and as well when we have transmission lines out of service for maintenance. So there's a whole raft of factors that play into that overall what we're going to achieve at the end of the year. But we do strive to maximize it as best we can, yes.

Q. And up to the end of September, you're running at 636 for 2003?

A. That is our record to date for 2003.

Q. When you file your updated evidence, do you intend modify the 624 number to reflect current data and the three projects we just looked at?

A. It's not our intention to change that recommendation, no.

Q. It is not?

A. No.

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Q. Okay. Is it possible to modify the table in NP-74 to assume those efficiencies that you told us about for the water lance installation, the Unit No. 3 rebuilder, as well as the experience for 2003 and come up with a modified composite number?

A. You mean if we were to add five kilowatt hours per barrel?

Q. Five to each of those and factor in the 2003 performance?

A. When you say to each of those, you mean to which particular ones?

Q. Well, I guess, I have to leave it to you as to what you would do with the 2002 data, as to when some of those projects came on stream, but I don't think any of them, from your testimony, affected the earlier years. So if there's an improvement of approximately five kilowatt hours per barrel, that five would apply to what, '96 through 2001?

A. It certainly wouldn't be appropriate to add that to--the water lance or the reheater to 2002 because they were in service.

Q. Yes, I understand that. But could it not be--could that not be done for the earlier data to

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make them comparable to the plant that you're now running now and then also account for your 2003 performance?

A. Our recommendation is to--we've put in these projects. We would like to verify its, I guess, its improvement over a period of time and let the average look after it. We don't really recommend going back and trying to change that. There are so many variables out there that influence that number and as you will see in 2003, even with those projects in place, except the Continuous Emissions Monitoring, we had 605, in June we had 588 and I guess, in August and September, they were 608 and 622. They were less than the 625. We don't--I mean, it can be done, yes.

Q. Yes. But if you don't do that, doesn't Hydro, as opposed to rate payers, take the benefit of that improvement in efficiency, because you haven't--none of that, apart from the 2002 year, on the two kilowatt hours per barrel item, it's not factored in at all, which seems to be Hydro then takes the benefit of these improvements, which have been paid for out of capital dollars, as opposed to rate payers.

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Would you not agree with that, Mr. Haynes?

A. I don't--I think I stand by the fact that we would do it on an average basis. When we are determining what our fuel conversion factor is, I mean, we're not doing it specifically for today. We're doing it for a number of years to cover off the next time we file, and there may be some improvement in the short term. It may be eroded over the long term, based on plant conditions, and if you go back to the chart that's on NP-74, you know, you have--you could use that analogy to add five kilowatt hours per barrel to 577. That's a low production year of approximately one terawatt hour. In 2000, it was less than a terawatt hour, you know, and in 1998, it was 1.2. So it's a difficult exercise to predict what our performance will be and we obviously are striving to improve it and to sustain that improvement, but we would really and very much like to prove those particular changes and to let the average look after it over a period of a couple of years, it'll start to creep up, if in fact they do pan out and we get that.

(10:00 a.m.)

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KELLY, Q.C.:
Q. Okay. We'll leave that one for argument then. Can I take you next to a couple of questions on hydrology? And this is at page 28 of your evidence. I'm not going to spend a lot of time at this, but I'd like to get some understanding of the status of this. If we go down to Section 7.2, if we could just scroll up a little bit, Mr. O'Reilly, there we go. You indicate that this Acres report has been done and then at line 24, there are a number of recommendations, "the longest reliable reference inflow sequence period of period of record should be used for all Hydro's operation planning and rate setting purposes." Just stop there. As we saw yesterday, you actually use, for the system, part of your planning criteria, you use actually the three driest years, as opposed to an average period?
A. That's for the long-term system planning to identify when new sources are required to meet our expected load, yes.
Q. And you, as the production vice-president, I gather from your evidence yesterday, don't intend to change that?

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A. No, that's pretty standard practice in pretty well any electrical utility or any particular group who looks after the long-term planning of a hydro system.
Q. Okay. And the second bullet is "the inflow sequences presently used by Hydro should be corrected to ensure internal consistency" and the report talks about data problems that need to be corrected and there's three points here. I'm going to give them all to you together. So the first one is the data correction for consistency, and then if you come down to the next page, line 4, just scroll up a little bit, it's "Computer simulation of the operation of the hydroelectric system using reference inflow sequences should be used to estimate energy production and spills from Hydro's hydroelectric resources. Hydro should review its in-house models and other models available and select one for these purposes." So item one is data correction for consistency. Two is model selection, and then it goes on "the above-noted corrections to the inflow sequences should be completed prior to simulating operations under the model, and

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since the system simulation models usually require a common start date for all inflow sequences, data from the early years of some inflow sequences will have to be cut off." So there are three items. Number one is correcting for consistencies. Two is selecting and running some kind of model and three is curtailing some of the data streams to get a common start date. Can you tell us what the status of each of those three components are and when you expect them to be completed?
A. Yes, I would add a caveat that the recommendation also by Acres was that these would not have any major impact on the overall outcome and they all can be readily corrected. With respect to the inflow sequences, Hydro has awarded a contract to SG Acres to review that and to do that and hopefully it'll be done towards year end, that we would actually have those inconsistencies in the data corrected, and I should also add that that was not on every reservoir. That was on--in some cases it was a distribution of the inflows in the Bay d'Espoir reservoir, not necessarily

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the whole. It may have been a split been Upper Salmon and Granite Canal and so on, but not necessarily the whole water shed area, and they, at Acres, suggested they were, you know, fairly minor.
Q. So before you go on, Mr. Haynes, that project or that part of the project, when will Acres report with that?
A. I think it's towards the end of the year that that will be complete.
Q. And will that be in a written report form?
A. Yes, normally that would be in a written report or a data set, whatever. Basically, it's an exercise to correct--statistically correct to standard statistical methods some inconsistency that they did see in some portions of the data.
Q. Okay. Could you tell us about the next one, the model selection?
A. I believe that's also under review to look at that, and that basically was on our--right now, I think most of the spills and fisheries are kind of on an average basis over long term. It's a refinement, basically, to what we're doing to allow us to do better. We do

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MR. HAYNES:
have some models in-house and they are being reviewed. I apologize, I'm not quite sure when that will be done, but it is in progress.
Q. Has Hydro gone outside, because the authors here talk about looking at the ones you've already got and then going outside and looking at other models as well, has that been--have you gone outside yet?
A. I did not review that actually, if we've gone outside, but I would suggest that if we have a model in-house that could do it, we would make our utmost efforts to use that.
Q. Wouldn't you try to get the best model, even if it means you got to go outside and look at the others as well?
A. Not if we've already paid for one that we own that can do the job.
Q. Is somebody in Hydro analysing that to determine which model should be selected?
A. The operations planning people would be reviewing that, yes.
Q. And when will they report to you on that?
A. I'm not exactly sure. I have not--I do not have that date in mind right now.

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Q. But I take it, it will be some time after you get the Acres report with the correction of the data inconsistencies?
A. Well, as Acres suggested, it would be appropriate to correct the data set before we proceed on that.
Q. So that will be sometime in 2004?
A. At the latest, yes.
Q. Okay. And then the last part of that is curtailing the data stream. Has that been addressed yet to know exactly which common start dates you're going to get for model simulation?
A. Yes. What we had proposed--the current filing is based on a 30-year average inflows, as directed by the Board in P.U. 7, and what we had proposed was that the earliest common date was, I believe, starting in 1950. So there are some years of historical information prior to 1950 that would be abandoned. But on a go-forward basis, we would peg 1950 and build on that in future.
Q. When you say you've proposed that, where is that curtailment at 1950 proposed? Is that somewhere in the evidence? Because I took it

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from reading this that that was still to come once you had corrected the consistencies and run the model.
A. What we had endorsed was the recommendation of Acres and I'm quite certain that's actually in the Acres report. 1950 was the date.
Q. So -
A. And we endorsed the recommendations of Acres.
Q. But by the time you get the model selected and the data done, it will be some time in 2004. Will you then be providing that to the Board and the parties, once that is done?
A. That has not been requested, but what we are proposing, as I mentioned when we started yesterday, is that we are not proposing to adopt that model for this particular filing. What we're looking for is resolution to the issue so that when we file future applications and for our year-to-year planning purposes that there's no doubt as to what we're doing. We'll have the data set cleaned up by the end of 2003. We'll have the appropriate models in place in 2004. So we will just carry on, on that basis, and the suggestion is starting at 1950.

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Q. The concern that we have down here, of course, is that we haven't yet seen: one, the corrected data; and two, the model runs in terms of its potential impact. So in order to kind of address it logically, you need to see that first, and hence my question. When it is done, will you be reporting it to the Board? So that we all have access to a final report with the corrected data and the results and conclusions of the models or the model.
A. If the Board requests, we will provide it. However, I should--I mean, I think when we get down into the nitty gritty of the hydrology recommendation, the most appropriate person will be Ms. Richter, who will be testifying on that there, but the basis is that based on the review done is that the best record that we have is a long-term average, which we are proposing to use. So regardless of the results, whether they are up or down or whatever the case was, there is no statistical reason not to use the long-term average, the whole data set as proposed, and the bottom line is that if it's up or down, I won't say it's irrelevant, it's of a concern, but that

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is the best average, the best number that we can provide and that's the one that we will propose to adopt regardless of outcome.
Q. But whether we all agree that it's best or not, or whether the 30-year moving average is best, it's hard to determine until you've got the final data, hence my questions as to when that is going to be available and what that is going to look like through the model. Is there a name to the model that Hydro is going to run? Like these are computer simulation models. Is there a name? Can you tell us the -
A. There's a couple names that come to mind, but I'm not certain. I'm not certain exactly which model it is.
Q. Okay. All right. Let me turn to a slightly different topic now and that is the Interruptible B issue. This deals with Abitibi in Stephenville. And I take it Hydro proposes to discontinue or not to renew that Interruptible B credit?
A. The contract expired last March, so it was signed in 1993 and expired at March 31st, I

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believe, of 2003.
Q. Okay. Maybe you could start by explaining to us what is involved in this issue and if you want, we can start by having a look at IC-194.
A. Yes.
Q. Perhaps you can start by just explaining what was being done with this Interruptible B contract and then why Hydro has decided not to renew it?
A. At the particular time when the contract was entered, there was, I guess, the LOLH or LOLE calculations at the time, there was a number of years difference between when we were going to have a capacity problem versus an energy problem, and Hydro entered a contract with Stephenville to allow them to request, on a fairly short-term notice, that we would want them to curtail load, in the order of 46 megawatts, and there was some limitations on the--basically it was for four months a year that we could do that and there was a limitation on the number of times we could do it, and so on.
Q. Okay.
A. It basically would affect--it would give us

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some capacity, peaking capacity, if you will, at a specified cost.
Q. And if we just go to NP-136 for a moment, the maximum capacity was 46,000 kilowatts or 46 megawatts, up to 25 times a year, for four months, December to March, which would be the winter peak potential season, at $28.20 a kilowatt?
A. That's correct.
Q. Okay. Now if we just flip back to IC-194 and explain to the Board why Hydro has decided not to renew this.
A. Basically, we had built generation with Granite Canal and two NUGS contracts and also, obviously, the load shape and so on, you know, other factors come together to change that. But in our forecast right now, we have ample capacity. We are meeting our reserve criteria of 16 percent. In fact, we are above that, as you do when you built any new plant, and we do not see any need to consider and Interruptible B type contract at the present time, and based on the current load forecast, current load shape and the factors that drive that, we don't see any reason to enter that in the

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future, in this particular point in time. The capacity deficit and the energy deficit are coming together within a year or so of each other and there's ample time to plan a next source or new source of supply to meet those needs.
Q. So would it be fair to say then from Hydro's perspective, the current value to Hydro of being able to take that 46 megawatts of peak off the system because you got lots of capacity, is currently zero? Is of no value to you?
A. It's not of significant value at this point in time, in the short term, no. You know, if the situation changes and we get into a case where we have a three, four, five-year variance between capacity and next source, it may be something that we would want to revisit with Abitibi or others.
Q. Right, but as we looked at Table 8, that is not the case for any of the--that's page, I think, 37 again, Mr. O'Reilly, for any of the period out to 2012?
A. No, that table excluded the 40, the Interruptible B contract.

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KELLY, Q.C.:

Q. Yes, it excludes the Interruptible B, so without Interruptible B in, you will not have a situation where capacity is exceeding the energy requirement all the way out to 2011?

A. That's correct.

Q. So is it Hydro's position that within the current foreseeable planning horizon that we talked yesterday about, the next source of generation will add both energy and capacity, that within the entire planning horizon that you can foresee, this 46 megawatts of peak reduction will have no value?

A. Based on the present assumptions regarding load forecast, load shape, et cetera, there's no merit to pursuing an Interruptible B contract.

Q. Okay. I take it, because of that answer, if you look at NP-139, Hydro has not investigated other opportunities for Interruptible B; in other words, other opportunities to take peak off the system?

A. No, we have not. We have not identified it as a need at this point in time. There's no--our load forecast and our calculations to date do

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not merit pursing that.

Q. And if we look at NP-138, I take it if you had a capacity deficit, then that's something that you would start to look at again?

A. As the answer says, we will consider any and all options that are available to meet our criteria.

Q. Is there any sort of principle that Hydro would apply in terms of assessing the value of an Interruptible contract to avoid or defer new generation in the future? Like how does Hydro approach that?

A. Can you repeat that question please?

Q. You say right now, like in the foreseeable time period, there's no value to an Interruptible contract to be able to take peak off the system. How did you come to that decision? Is there any kind of an analysis that you do to determine what the value is? How did you get to zero value?

A. Primarily it's a cost consideration, you know, with the construction of Granite Canal and the entering of the two Power Purchase Agreements with the Corner Brook Pulp & Paper and Exploits River Hydro Partnership, we have

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ample capacity and energy to meet the short term or the foreseeable needs until 29--2011 and it's a matter of cost. There's no basis in cost to actually enter into agreement for capacity that we do not need to meet the criteria of.

(10:17 a.m.)

Q. You talked a little bit with Mr. Browne about Demand Side Management, and I take it from your answers to him, that Hydro, at least in terms of anything on the Interconnected system, has no plans to do anything with Demand Side Management in terms of paying people to do things differently?

A. No, we do not, but I would suggest--sorry, I shouldn't suggest, I should add that the biggest opportunity for some of that would be with Newfoundland Power's customers, which vastly overwhelm the number of customers that Newfoundland Hydro has.

Q. Okay, but if Hydro thinks that there is some benefit in doing it, I take it you would do it with your customers as well, would you not?

A. The gains of Newfoundland Hydro's twenty-odd thousand customers versus Newfoundland Power's

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200,000 customers would be quite different. The "bang for the buck" if you will is in the larger customer base.

Q. If--when you talked about the Rural operations yesterday, with Mr. Browne, you said that when you get to a capacity constraint on your Rural system, at that point in time you look at whether Demand Side Management--whether there's any viable options there. Do you remember that evidence?

A. Yes, most of that activity is directed to the Isolated Diesel Systems where the marginal cost is extremely high, compared to our returns.

Q. Here's a couple of questions that kind of flow out of it. Why do you wait until you get to the capacity constraint to look at that?

A. Because that's what spurs capital investment in new plant or new transformers or whatever. We looked at that in our capital proposal for the addition of a transformer in Goose Bay, for instance, which is an Interconnected Labrador, we looked at the opportunities and basically there were none identified that would be economic. It's based on dollars and

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MR. HAYNES:
cents. What is the most economic -
Q. So until you get to that capacity constraint, it's essentially your position it's not worth doing, is that the bottom line?
A. I don't think that's the bottom line on the larger Interconnected System, but certainly in the Isolated Diesel areas, that's the approach that we've taken because there are so many different systems and there are so many variables.
Q. Okay, and you'd have to look at that system then and the factor that you said you looked at was, well what would be the marginal cost of doing it?
A. I should add too that in the Isolated Diesel areas, the penetration of electric heat is nowhere near what it is in the Interconnected areas, particularly on the Island. And one of the principles, I guess, or one of the things on Demand Side Management was that electric heat and hot-water heating would be the two major contributing factors to potential savings.
Q. But the marginal cost, you told us, is the

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factor that you would look at; in other words, if you're going to put in--Hydro's had programs, for example, in some of these places to put in low energy fluorescent bulbs, correct?
A. That's one of the things that was done in some areas.
Q. And I take it that in doing that, you made some kind of marginal cost analysis of what is the cost of doing--spending this money now to do that, versus spending money now to add a generation capacity in some fashion?
A. Generally, yes.
Q. That's how you would go about doing it?
A. That's how we've done it in the Isolated Diesel areas.
Q. Okay. Has Hydro performed any kind of marginal cost analysis on the Island Interconnected System?
A. Not of late, no, that was quite a number of years ago it was done.
Q. I think the last one was done about 1984? Does that sound about right?
A. That's sounds correct.
Q. Okay, would you agree with me that before you

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would want to--especially in the circumstances which you have just described about the capacity that the system has, the fact that your Interruptible B has currently no value, before you would engage in some of these Demand Side Management things, would you not need to do a marginal cost analysis to determine what, if any, value you would get out of it?
A. I don't think you--it would require to do that, I mean, we're not talking about a marginal cost system, we're talking about a marginal cost base. If we're all paying marginal cost, we would definitely over earn, so I think the data that was generated in 1984 is used and useful, and I don't think the lack of a current Marginal Cost Study precludes continuing, you know, entering that exercise or pursing a Demand Side Management or demand energy rates. I don't think that is an absolute necessity to proceed.
Q. Okay. Let's just take you to NP-167 for a moment and the answer at 167 is that DSM shouldn't be evaluated on a marginal cost basis, in fact, that's just the discussion we

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had about the Rural system. If, in fact, let's take a potential project, let's take water heater controls that you're going to try to put in place to take something off of peak, and we just had this discussion about the capacity that your system has got, the lack of value, as you see it, in taking 46 megawatts off a peak. If you were to put in heater controls so that for all the customers, so that the electric hot water heater no longer comes on at 5:00, it's going to be postponed until 8:00 at night, would you not need to analyze at what point in time that becomes cost effective? Especially since right now your system has adequate capacity to meet the peak?
A. Our system has adequate capacity to meet the peak right now, but I think if you were, you know, as you go down the DSM, demand energy rate that what you're going to do is you're going to increase the--or have effects over a period of time. They're not going to be instantaneous with respect to the planning horizon, but you may improve the load factor of the Newfoundland Power load and so on. So

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MR. HAYNES:
it's not a short-term fix, it's basically a longer term moulding the load growth and, you know, the demand energy characteristics of the system over a period of time. You would never see something--the outcome is going to affect us in one year, but you will see it over a period of years, that's the theory.
Q. Explain to me how you square that answer with the fact that Hydro doesn't see any value in taking 46 megawatts off of peak with Interruptible B?
A. The Interruptible B does not actually remove very much energy. It's more of a--it was a short-term thing to get over a capacity problem. I think that if you have a demand energy rate and however Newfoundland Power were to choose to change their rate structure to reflect that, that you will impact the overall energy requirements of the Province over a period of time. And I think that's where the gain would be, and it's fairly accepted.
Q. Have you studied Newfoundland Power's rate structure?

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A. No, we have not studied specifically Newfoundland Power's rate structure, but I would think that--I would assume that Newfoundland Power, if demand energy rate happens in the short term, that they would look at their rate structure and propose a rate structure that covers their particular concerns.
Q. But do you have any sense, if there is to be some benefit out of this to the system, then in what way does Hydro suggest that Newfoundland Power's rate structure should be modified? Have you addressed that question at all, Mr. Haynes?
A. I personally have not had any involvement in that, but you know, we do have Stone and Webster and the Rates Department who may be able to shed some light on what other jurisdictions do.
Q. In fact, if we put up PUB-148 for a moment, in fact the Board's staff put the question of assuming you were an integrated utility, would Hydro have employed a different strategy over the past decade, to pass through a demand price signal? And the answer, essentially, is

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due to the absence of either the experience of a hypothetical utility or data to support an alternative, no different strategy can be surmised. So I take it, not only have you not studied it, but nobody in Hydro has studied the issue?
A. Not of late, from that point of view. There was a lot of discussion in the 1990 hearings with Mr. Brunneau or Dr. Brunneau and so on, who were quite adamant on the demand energy rate and the fact that they would, Newfoundland Power would need the right signal from Newfoundland Hydro to make that happen. And I have to admit that I am not--cannot shed much light on their rate structure and so on. That would be more Mr. Banfield's and Mr. Greneman's -
Q. But you have shed a good bit of light on how the demand and energy characteristics of the system have changed since 1990 to the current date?
A. There's been some change in load factor, yes, overall.
Q. Let's move from that to a slightly different topic, just bear with me for a moment while I

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get organized here. I'd like to go next to look at a couple of expense items, Mr. Haynes.
A. Okay.
Q. Can I take you to Schedule 6 of your report?
A. Yes.
Q. Bear with me for one second. Now I'd like to go to the salary line here, and I just want to understand, first of all, how this works. If we go to line 4, you've got something called "permanent salaries" and you see if you go across that to 2004 forecast, it's forecast to be 18.47 million?
A. Yes.
Q. See that line?
A. Yes.
Q. Now, if I could start with permanent salaries, what happened to the concept of FTE's and where do the temporaries fit into this table?
A. We had changed that all salaries for permanent and temporary employees are now included on line 4.
Q. So that line, even though it says "permanent" is -
A. Is a total.
Q. Is a total?

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MR. HAYNES:
A. Yes.
Q. Okay. And with the capital projects completed and notice as you come across the overtime line, you still got a million, four hundred and seventy-five thousand in overtime, and if you go back to 2002, that's not radically different than the 2002 actuals in which there was a substantial amount of overtime that was, in fact, capitalized. I'm wondering if you can help us understand the reason for that?
(10:30 a.m.)
A. The reason for that in the sense that each year that we are actually undertaking capital projects, any overtime worked by our employees, our employees that they actually work overtime on a capital project, is charged to the project as a part of that, so -
Q. Yes, but those capital projects are essentially now over, are they not?
A. Oh no, there are still ongoing capital projects, I mean, Granite Canal is done but there are other projects that may require overtime and there is a considerable bit of overtime in some of our operating areas, such

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as Holyrood where you have a mandatory shift complement for steam plant operators and so on.
Q. But with Granite Canal finished, why is overtime at one million four seventy-five only about $200,000.00 less than the total overtime for 2002, or am I not reading this correctly in some fashion?
A. As I mentioned to Mr. Browne yesterday, that we never had a big contingent of people dedicated on a fulltime basis to Granite Canal, there were probably five fulltime. Most of those particular employees are not eligible for overtime. They basically are paid an allowance in lieu, which is pretty standard practice for our engineering staff, most of our engineers do not actually get paid overtime. They get an allowance in lieu of, so you know, some of the overtime that would be associated with the Granite Canal in 2003, would be from our operations people who were at the site there, as they are today, doing the various things until it's signed off.
Q. At the end of 2002, can you tell me how many of the permanent positions, as shown there in

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your department, were vacant?
A. In 2002?
Q. Do you have that information?
A. I would suggest it was probably eight to nine positions were actually vacant in Production Division.
Q. Eight to nine were vacant in the Production Division?
A. Less than ten.
Q. Okay, well nine would be less than ten. Are they in any particular department or spread throughout all six departments; in other words, is there any particular pattern or reason?
A. There were--they're spread over various areas, but primarily typically because of the numbers of people that are in the departments, the largest number would have been probably in Hydro generation and in thermal generation. They typically usually are the largest number and when we do have a vacancy, we usually--to meet our vacancy reduction targets, we usually stagger, rehire and review the position wherever it's need and so on.
Q. So just explain how that works, to meet your

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targets? Just explain that, what does that mean?
A. For the last number of years, we have included approximately--from a corporate level, approximately a million dollars a year in vacancy reduction which basically looks at the--we do our budget based on full complement and at the bottom of or at the end of the expense within the salaries, we include a number for vacancy reduction. It reflects the time lag between somebody leaving a position and somebody being hired into it. Depending on when somebody leaves, we may leave that position for a number of months before we rehire because it's at the end of the season, whereby, you know, we may feel that we need the position on a fulltime basis, but there is an opportunity to escape for several months or two or three months until we refill because it's in a low-maintenance period or whatever. So those are managed on a department basis. Each department has that allocation of anticipated savings because of vacancies.
Q. And I understand you have a policy of when a position becomes vacated that you look at

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KELLY, Q.C.:
whether there can be some reorganization to eliminate that position?
A. We review each--each permanent position that's vacated has to be approved before it's filled and we look at whether the job could be done by others, whether it could be moved to another location. We look at any opportunities to do that, as they become vacant and some any time.
Q. Can I take you to your testimony on this at page 14 at lines 9 to 11? And you say at line 9 there, talking about the 6 percent, "this reduction was achieved by various means, including reviewing vacated positions and the operational needs of our plants through technological change." Now, there are two components, I take it when a position becomes vacant, you look at reorganization around that position? That's the first one.
A. We look at the duties that are done, if they can be done by others, they can spread among another group or whatever, it's not necessarily quote, unquote, capital load reorganization, but we will look at the

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departments, we will look at, you know, we've done that consistently, looking at merging departments and so on.
Q. And what about the technological change? Where have you reduced your technological change in your divisions?
A. Maybe an example would be most appropriate. In Holyrood we obviously operate under the Boiler and Pressure Vessel Act of the Province and in our previous license, there were more or less dictated how many operators we had to have on shift to look after that major steam plant which is basically the biggest steam system in the Province. And we had, obviously we had put in technology over the years to provide the operator more information and what we had done is we had actually reduced the on shift personnel in Holyrood by one operator in that time frame, which accounted for some of that reduction. So we had gone from, I believe, six or seven--six operators on shift, down to five, plus the supervisor.
Q. And so that's in your thermal department?
A. That's in the thermal department.
Q. Are there examples in any of the other

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departments that come to mind?
A. Yes, in the IS&T where we can do a lot more troubleshooting on a person's PC and their desktop by, if you will, I'm sure it's not the right word, by remote control, that the client support analyst or the help desk in St. John's can actually take over somebody's PC, for instance in Port Saunders, and troubleshoot and fix things, as opposed to having people out there. That was one of the reasons we reduced a number of temporary client supportive systems that we had.
Q. And when did that take place?
A. That took place in early 2002, I believe.
Q. 2002?
A. Yes.
Q. Okay, how many positions are vacant in your division throughout your departments as of the end of August, 2003?
A. There are, at the moment, I believe there are ten positions vacant, as we speak.
Q. So there were somewhat less than ten at the end of 2002 and they are currently about ten--there are ten positions vacant as of today, October?

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A. They're not all the same positions, but there are approximately ten positions vacant today.
Q. As in October?
A. Yes.
Q. I'm just trying to get the time frame right, okay. Now, can I take you to NP-9 and page 2 of 6, and these are the number of permanent positions, if I follow it correctly, in your division, up to August of '03?
A. Yes.
Q. Okay, now what I'd like to do, is I'd like to look through this with you, because the departments have changed a little bit over the years. Let's go over, first of all, to the one that's called "Generation Engineering and Telecontrol", which has entries for only ' 97 and '98. Do you see that?
A. Yes.
Q. Okay, and there were, at the end of '98, there were 65 people in that department. And if we look at the columns, as we tried to figure out where that 65 went, 20 seemed to have gone over to the next column, which is "Generation Engineering"?
A. Yes.

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KELLY, Q.C.:
Q. And 12 seem to have gone over to "Generation Operations", you go from 5 up to 17?
A. Yes.
Q. And the balance went over to "Telecontrol and DMS", the next column over?
A. That's basically correct, yes.
Q. Basically correct.
A. Uh-hm.
Q. And in the meantime, in that same year of 1999, you had 36 people come in from outside your department in IS&T? In fact, they were transferred from your finance department, weren't they?
A. Yes.
Q. So if we look at your IS&T column in 1999, you have 36 that come in from finance and if we just quickly go over to page 5 of 6, you'll see '97 and '98, they got this MIS of 36 and then it drops to zero in 1999.
A. Yes.
Q. So if you just go back to page 2 of 6 now, so in the--if we go to the total, you start in 1997 with 277 personnel and you end up with 301, but you added 36 people that came in from

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finance, so if we add those in, we'd have 277 plus 36, would give us 313. We end up at 301 for a net reduction of 12?
A. Well there were other changes through the period of time, the economic analysis department also moved over to system planning. When you went from 10 to 13, there were three individuals transferred also from the finance department at the time.
Q. So you had three more that came in there?
A. Yes.
Q. Okay. And they came in in 1999?
A. They came in in 1999, yes.
Q. So if I add on those three more, I'd get essentially 15 in terms of reduction, in your total complement? I'm just trying to get an order of magnitude here, 12, 15, that's pretty close for the purposes I want to have a look at here. Are those the main drivers?
A. Based on the way you've done it, yes, I mean, I don't take exception to your 315. There are other changes, obviously, over time, depending on the needs of the Corporation, the needs of different areas.
Q. Right.

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A. Hydro Generation went up by three, so there are several, you know, it is very difficult to go back and try to rebuild the history because we have not kept it, so it's out best attempt to do that.
Q. Okay, but here's the point that I wanted to try to come to, when we look at those and we go to each of these columns through your generation operations, it started with 5, you had 12 come over, which is 17 and essentially you end up with 17, so there's no significant change in the generation operations department?
A. No.
Q. In the Hydro generation, you start with 85, you end up with 86, so you're up plus one, no significant change there. In the thermal generation though, you're at 113 and you end up with 99, for a total reduction there of 14.
A. Yes.
Q. And we can do that exercise all the way across, generation engineering from '99 on is still 20, and your systems planning starts at 10, ends up at 12, so there's a small change there of 2. Your IS&T, you've got some coming

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in, 70, and then you end up at 67, some small change there. But the only department with any, what I could call significant changes is in your thermal generation. Out of 12 to 15 in total, 15 of them seem to be thermal generation changes and I'm wondering if you could explain why, since 1997, there have been no significant changes in any of the other departments?
A. Well, I guess we are responding to the maintenance requirements of the system and the information requirements of the system. Holyrood presented itself as having more opportunities for reduction based on a number of thermal plant operators that we had and based on the merging of some departments. And there is--I mean, we have looked at all these departments from the point of view of need and continue to do that and have, in our vacancy reduction targets, will continue to look at that and the additional one and a half million dollars that we put in there for 2004. We are doing process review. We're looking at many processes and there may be changes, depending on what the work demands are. But Holyrood

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MR. HAYNES:
obviously, as you mentioned, was the most significant change to date.
Q. But you have not quite as many, but almost as many people in the hydro generation, yet there's no--there don't seem to have been any efficiencies achieved in terms of reductions in your hydro complement.
A. No, not at many in a direct number sense, however we did have Granite Canal in 2003 and we are not adding any additional operating people or engineering support people to look after that plant.
Q. Should that plant be essentially automated?
A. Well, as is Cat Arm and Hind's Lake there, except for Bay d'Espoir.
Q. Yes.
A. They're by and large all operated, but they all require, obviously, resources to do. I would also add that one of the key differences in hydro generation and thermal generation is that basically the thermal generation people are at one facility. So, basically you have 99 people who work at the thermal plant in Holyrood, of which 30 or so are operators. At

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the hydro generation you have people spread over from Paradise River to Cat Arm, Hind's Lake, Granite Canal. So, there's more travel time, there's more--I won't necessarily say lost time, but it's obviously not as desirable that they're all in one specific plant where you could have a better opportunity to address some cost saving measures. But with distributed generation, it's a bit more difficult to nail down the significant change that we've achieved in Holyrood.
(10:45 a.m.)
Q. Can I show you, from the 2001 General Rate Application, NP-31 and we've already provided you with a copy and the clerk will distribute this one.
MS. NEWMAN:
Q. This will be Information Item number 14.
KELLY, Q.C.:
Q. I'm sorry, number 14?
MS. NEWMAN:
Q. Yes.
KELLY, Q.C.:
Q. And this deals with the Haddon Jackson benchmarking study, Mr. Haynes. Are you

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familiar with this?
A. Yes, I am.
Q. Okay. I'd like to take you to a couple of pages of this, if you would come over with me to page 21 and this was reviewed with the Board in Hydro's 2001, at page 12 under Performance, "operation costs for the Bay d'Espoir station group was poorer that expected, exceeding expected costs by about 50 percent". And down on the bottom, there are improvement opportunities. The Bay d'Espoir station group prepares to have opportunities for improvement. Other leaders have shown that elimination of routine technical operators staffing at automated remote facilities will take full advantage of station automation to reduce costs. And then you go in the next one, "if they are going to be operators present, then they could be involved in doing routine work". So, that was one area that was highlighted. If we go to the next page, I'll give you these all together and get you to comment. Under Plant Maintenance, "the Bay d'Espoir station group cost performance in the small, medium, less than 45 year old

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segment was poorer than expected with costs of about 28 percent above average". And then there were a number of recommendations for improvement on the bottom, including the first one there, reducing layers of management, et cetera. And the final--I'll take you over to the next page which is WW&D, what is WW&D Maintenance?
A. Water Works and Dams.
Q. Water Works and Dams, maintenance costs for both Bay d'Espoir station group and blank were higher than average. Bay d'Espoir costs were about 55 percent higher. And again, down on the bottom, the recommendations for improvement opportunities included flatter organization, flexible workforce, reduced maintenance strategies, in favour of periodic investment may offer opportunities here as well. And I'm wondering if you can explain to us what has taken place since the 2001 hearing with respect to this?
A. I will. I'd like to just comment on a couple of things on the Haddon Jackson report. First of all, just to put it in context of the approach that was taken by Newfoundland Hydro

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MR. HAYNES:
at the time, when we undertook this particular project with Haddon Jackson to do a benchmark study of the hydro facilities, we treated all of hydro generation as one station. And when you go through the main body of the large report that was a companion to this report. Most other utilities and I will just mention a few, BC Hydro had 10 stations there and they actually undertook 10 separate reviews. They didn't look at, you know, Peace River, et cetera, et cetera, as being one consolidated thing. What we had done in the interest, I guess, of saving money to some degree was we had lumped Bay d'Espoir, Hind's Lake, Cat Arm, Upper Salmon, Paradise River and called it one plant. So, you obviously get some difficulties in comparing apples and apples when you consider the travel requirements and the distance between those. BC Hydro had 10 different evaluations done. Great Lakes Power had 4. Hydro Quebec had 8 and so on. So, there's some context required. It doesn't mean that there's not useful information provided by Haddon Jackson with opportunities

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for reducing that.
I'd also like to take you to page 6 of the report whereby we have a functioning cost per megawatt hour. And if you look at that particular chart, and I guess that's not available electronically, on page 6, the average is roughly about, I guess, a little less than eight dollars per megawatt hour. And there's an average line drawn across the page and of all the plants that were considered which were some two or three hundred, Bay d'Espoir is indicated on that chart, you know, less than average cost when it's prepared in that context. So, while there are suggestions in the report, I don't think it's damming from the point of view of our overall performance. And if you turn the page to page seven, they've separated medium hydro plants which is also the way Bay d'Espoir was treated. And that particular chart on the top right hand page, we are again, less than average of all those factors. So, I just try to put that into context that while there are certain areas of the Haddon Jackson report we are higher and there are

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certain areas where we are lower, but on the overall, you know, we didn't fare that bad. But there are recommendations in that particular report that certainly have merit and even though, it was not done, the review of the benchmarking was not done in an ideal way, in the interest of reducing costs, it certainly was--it certainly gave us some general guidelines, some indication of where we have some potential to save money.
So, if we go to page 11 and the focus here for medium hydro, these are the split of costs between the various areas. Medium hydro, that is where Bay d'Espoir is. So, this is the average for about that particular segment, medium hydro. And then if you turn the page to page 12, you have Bay d'Espoir. So, you know, there are some, you know, support costs, they're ten percent different, building and grounds maintenance is pretty well the same, dikes and dams, there's 11 percent for that as Haddon Jackson did point out. We do have quite a bit of, you know-- this report is benchmarking, looks at, tries to put in context and levelize the playing

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field for all these different plants. Some run of the river plants with one dam, you know, some other plants that have multiple facilities and we do have multiple facilities. So, there's some caution there. When you get down to other parts of the report, you know, with specific recommendations, we have done several things that are in line, if you will, with some of the Haddon Jackson commentary that we did receive. We, as I mentioned already, we've incorporated Granite Canal, another plant, another unit into the Bay d'Espoir operation with no increase in personnel in the operations or the engineering support group. We have, in the last contract negotiations, changed the role of remote plant operator to do more maintenance. At one particular time, they were basically operators and pretty well, each and every deficiencies or problem that arose, required electricians, mechanics or technicians to come from Bay d'Espoir or other places to help. Right now we are moving some of that trouble shoot capability and repair capability within the remote plant operators capability for them to

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MR. HAYNES:
do with less requirements from Bay d'Espoir. When we are into those particular areas doing overhaul maintenance work, the operator now works with that particular group. Whereas before he would basically do isolations and protection code things, but actually working with the group would be a very, very minimal thing. Right now that is changing as we move from a shift worker to a day worker.

With respect to Paradise River which is a small remote plant, we have relocated that particular position. We do not have an operator in the Burin Peninsula area anymore. That particular position is being relocate to Bay d'Espoir and that is being done through the Bay d'Espoir group. You know, the maintenance crews will, as they have for a number--since day one, be dispatched from Bay d'Espoir, but as a small plant, we do not see merit into maintaining a full time presence at that particular plant. It's sufficiently instrumented, there's sufficient information going back to the Energy Control Centre to allow them to dispatch people or call the

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maintenance people to have someone there. We have moved into the area of computerized maintenance systems and in our current activities and business process review, are looking at our work methods and so on. And we see from, we are expecting and anticipated some improvements over time with that as we progress down that route and have incorporated some increase in our vacancy reduction numbers to account for some improvements. They may be personnel, they may be anything, but the actual dollar savings is there.

One of the things too which was mentioned, I guess, by Mr. Kelly was that on some of the remote plants, you would actually remove--well, they didn't say actually remove, but you would have less people in the area, sort of thing, to do that. We don't consider that appropriate for Newfoundland Hydro. We have taken that approach in Paradise River. We would not take that approach in Granite Canal or Hind's Lake. We have a number of people in the Deer Lake area who basically look after the day-to-day maintenance of

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Hind's Lakes and Cat Arm. Because those particular plants are critical to our role in providing, meeting our mandate, we do not think it would be appropriate to take those people out of those areas. It's too far away, the time delays are too long, the plants are too important. On some smaller plants, for instance, at Snooks and Venam's, we do not have people in the area. We have a small contract with a caretaker, sort of thing, to look after it, but that's a minor cost. Paradise River, as I've mentioned a couple of times now, we've actually gone the other way.

We have made changes in our purchasing and our goods and consumable things to waste less time, if you will, going to the warehouse to pick up consumables as was mentioned a few days ago by Mr. Roberts and Mr. Wells. I don't recall now who. And we have, you know, used purchasing cards, we have changed around that goods and services supply thing to better accommodate the needs of the plants to reduce that particular effort. So, over a period of time, we see making some gains on this and improving our record compared to others.

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Q. After you got this report from Haddon Jackson, did Hydro do any internal study to see how it might reorganize the structure the Hydro division or department in view of Haddon Jackson's recommendations? Was there any kind of internal study done to look at this?

A. It was reviewed, but there was no "formal review" in a sense of sitting down and analysing each particular thing and writing a report. This report obviously is in the hands of the plant manager at Bay d'Espoir and when we are making changes, see opportunities, it is used to, I guess, to give us some guidance on possible areas of improvement which, we've undertaken several.

Q. But was it only dealt with at the level of the plant manager at Bay d'Espoir, as opposed to your level of vice president to look at how this department might be reorganized with, you know, as a flatter management structure, et cetera.

A. The -

Q. I take your point that, you know, Bay d'Espoir, as you say, some of the caveats that you've talked about, both Hydro's mandate and

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KELLY, Q.C.:
the Board's mandate is still the least cost generation.
A. The organization structure at Bay d'Espoir basically, you know, when you look at it right now, there's a plant manager, there's a labour manager, an asset manager and their supervisors and that's it. There is no six or seven rungs to the ladder, if you will, in the hydro plant area. So, I think the organization structure is reasonable flat now. I don't think there's a lot of opportunities, there maybe here and there, some, you know, a couple of things here and there, but there's no major organizational structural issue with the Bay d'Espoir or the hydro generation area.
Q. This would be an appropriate place to break, Mr. Chair.
CHAIRMAN:
Q. Thank you, Mr. Kelly, Mr. Haynes, we'll reconvene at 11:30 a.m. Thank you.
(BREAK - 11:00 a.m.)
(RESUME - 11:36 a.m.)
CHAIRMAN:
Q. Thank you. When you're ready, Mr. Kelly.

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KELLY, Q.C.:
Q. Thank you, Chair. Mr. Haynes, I just want to finish up this discussion we were having about NP-31 from the previous hearing. And can I take you to the October 10, 2001 transcript at--discussion begins at page 2? It begins at the bottom of page 2 with Ms. Butler asking about NP-31. And if we go over to the top of page 3 at line, approximately 50, 51, 52 Mr. Henderson is answering, and he says "We're looking at our maintenance practices, our staffing levels in different areas. We have not made--come to any conclusion. We're just basically at this point studying this report and we will be expecting to start implementing some changes as a result of this in the next year or two." And down at the bottom of that page at lines 98 to 101 he makes a similar comment. And I'll take you over to page 4 to line 40. And Mr. Henderson says, "They are being considered, as I mentioned, but there has been no action taken on these other than the fact that we are reviewing them with our new vice-president in position." I take it that would be you?

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A. Yes.
Q. "This is one of his items that he has to address with the manager of hydro generation to look at what of these we can implement." And Ms. Butler says, or asks, "So there are no potential savings reflected in the test year from any initiatives that may be taken from this report?" Mr. Henderson answers, "No." And I take it that as we looked at NP 9, that there have, despite this report, been no changes in the staffing levels at--in the hydro department at Newfoundland Hydro?
A. There has been no specific staffing changes in the hydro department. I mean, there have been some--there have been increase in plant, as I mentioned. We added Granite Canal, which was obviously a consideration. When we added Granite Canal, there may have been a perceived notion that we would increase staff. And that was discussed thoroughly with management of hydro plant operations and we proceeded on the basis there would be no increase in staff for Granite Canal. We have addressed other items that were in the Haddon Jackson Report which was, as again I mentioned, with respect to

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Paradise River, relocating the operator to maximize the resources of the whole. We've changed the working conditions or the working hours, if you will--not the hours, but the assigned hours of the remote plant operators from a shift operation to a day shift operation to better employ their skills and abilities in the maintenance and operation of those plants. So, even though there has not been a reduction in the complement at Bay d'Espoir, we have undertaken several initiatives to improve that particular operating footprint, if you will, of Bay d'Espoir.
Q. Are there any savings from the Haddon Jackson Report and any of what you've said been incorporated in the 2004 test year, and if so, how much are those savings?
A. All the savings, I may be a little bit difficult to put a number on some of the initiatives that we did there, but if we go to, if we go to--excuse me for a second. If you go to NP-87, and this excludes the discussion that Mr. Wells had or Mr. Roberts had on the goods and services where we made

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MR. HAYNES:
change to effect all these particular plants, not only Bay d'Espoir but other ones, but we anticipated over time that we would save, on page 103, about approximately $100,000 a year by more adequately employing the remote plant operators to do maintenance and to--and moving them from a shift operation to a day shift operation. At item No. 2 there was a small amount of money, but nevertheless, it's an activity that helps by relocating the plant operator position from Paradise River to Bay d'Espoir and that would also have been a factor in us not actually hiring additional operators or maintenance personnel for one additional plant. You know, we have five major plants, now we have six, so we've taken on, you know, another machine and another maintenance activity with no increase in staff. So there's no dollar value, a dollar value tagged to that, but it's a definite saving and will reduce our per megawatt hour, per megawatt cost, whichever way you want to measure it. These are the two primary ones on a single basis at Bay d'Espoir which would

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facilitate that there. With respect to the materials management on goods and services, those things had been done. And all those savings are reflected in the 2004 test year. And further, on a corporate level and--of which the production department has been assigned, I forget the number offhand, but it's readily available, the production division has also been tagged with, not a very good choice of words, $925,000 in vacancy reduction as well as our share of the one and a half million dollar corporate reduction that we anticipate over the ensuing period of time with respect to business process review and things of that matter.

Q. How many of those vacancy--how many of those positions are vacant now in the hydro section? You told us overall there's 10 vacant. How many are in hydro?

A. Just one second. At the present time in hydro operations we have five vacancies.

Q. And has it been looked--are you looking at eliminating any of those five positions permanently, or are they all going to be filled?

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A. All the positions are under review. Some of the changes--some of the positions are actually maybe being partly done by temporary labour, depending on the particular role. When we go back to, I guess, an earlier question this morning on organizational structure, we did make an organizational structure change at Bay d'Espoir when we moved the operators who were now taking on more of a maintenance role and operating role. We've actually moved them to the labour manager, which was kind of consistent with the approach that Haddon Jackson had suggested and so on. But all the five positions will be under review.

Q. But so half of your vacancies are in the hydro generation department which has not yet seen decreases in complement. And while you say they're under review, can you give the Board any sense as to what Hydro's plans are as to whether you intend to eliminate some or all of those five positions?

A. We do not have any specific plans to eliminate any of those positions at this point in time. We are reviewing, as I mentioned. Some are

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being filled by temporary efforts and there are some--there were some--all the particular activities of those particular people are being reviewed, but we have not concluded that we can do without them at this point in time.

Q. Okay. The need for operators for Bay d'Espoir and whether that facility could be remotely operated, has that been analyzed at all by Hydro in recent times with new technology, etcetera?

A. Not in recent times it has not been looked at. I think it was some number of years ago. And the Bay d'Espoir plant has not been--it would require considerable capital and you will still need operators. But Bay d'Espoir plant right now is manned 24 hours a day with an operator.

Q. Has Hydro performed or do you intend to perform any kind of cost, benefit analysis to look at that as a potential alternative to reduce complement?

A. We have not considered doing that for the remote operation of Bay d'Espoir plant for a few reasons. Primarily, one of the key roles of the operators at the Bay d'Espoir facility

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MR. HAYNES:
is that we do not have operators on shift at any of the other remote plants. The energy control centre looks after the system, dispatches units, can start, stop machines other than Holyrood and Bay d'Espoir. But the Bay d'Espoir personnel do have a fair number of duties and roles with respect to the remote plants. The energy control centre would not be--they are dispatchers, they do not get into plant operating specifics. They don't, you know, go into the plant and turn on things within the plant. That is left to the Bay d'Espoir operators who look at that for remote plants, as well, and do things like that. So we have no current plans to -

Q. Automation is not being even analyzed?

A. Not on the--it has not been for some time. We have looked at automating certain aspects of our Bay d'Espoir hydro plant operations with respect to some up country structures. Some of that work is ongoing now, but we do not have any conclusive results to make changes. But if they have changes are--if the changes are economic to do, then we would put them

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forward as being valid capital budget proposals -

Q. That's what I was trying to get a handle on as to are you doing a cost, benefit analysis study to determine whether some of these things are cost effective?

A. We're not looking at the hydro plant, per se. We are looking at other aspects of the hydro plant operations such as some of the remote structures up country.

Q. Okay. When will those studies be completed?

A. They will be completed late this year or early next year. That's an in house, a desktop study to see if there's merit in continuing further.

Q. So late 03 or early 04?

A. That would be the time frame.

Q. Okay. Can I ask you a couple of questions about maintenance? We've heard and Mr. Wells talked about reliability centred maintenance and there's much discussion of that in the TRO section, but less so in yours. Does it apply in production or--and if so, what are the implications?

A. It has some applications in production. We do

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employ RCM at the gas turbine in Holyrood and we are reviewing some RCM applications in the Holyrood plant as such, certain systems and so on, not the whole plant but certain aspects where there may be some redundancy. In the Bay d'Espoir hydro generation as a whole we have not undertaken a full scale review and we have some, we have some reservation about moving to a, you know, to the philosophy of full scale RCM approach primarily because some of the plants are remote and run into failure when you have the distance and so on and the potential of spill is--has to be weighed against RCM. You know, we do--you know, there are several maintenance tactics that you can employ, RCM is but one, you know. And we do computerize maintenance planning. We have condition based monitoring for certain things, but we have not--we have not pursued a full RCM review for the hydro plant. We have some reluctance and some doubts about whether it would be really effective for that particular -

Q. Is it being studied in your division?

A. Not in the hydro plant, per se, at the moment.

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We are reviewing some potential applications for some subsystems in Holyrood -

Q. You have Holyrood -

A. - we have not looked at it in whole for hydro -

Q. If I take you to MP-277 which asks about reliability centred maintenance and we go down through the answer, the answer covers transmission, distribution, terminal stations, diesel plants, gas turbines. And then at the end at page 3 of 3 there's a breakdown of what the million dollars is. They all, at least on first blush to me, appear to be in TRO. Am I missing something here?

A. No. That's correct. That is a TRO initiative, and the gas turbine cost quota would be for the gas turbines that are maintained by TRO, being hardwoods in Stephenville and Goose Bay.

Q. Are there any reliability centred maintenance savings in the production division?

A. As I said, we have not reviewed it in dept for Bay d'Espoir. We are reviewing it with respect to some systems in Holyrood and we have employed it for the gas turbine at

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MR. HAYNES:
Holyrood, but I don't know what the savings are offhand.
Q. Okay.
A. So we are looking at it with caution and where you have a potential for spill, major damage, it--my personal view, I guess, is that on RCM, I think there are lots of benefits to RCM, but you have to look very specifically at what particular facet of the operation you're looking at. On a distribution system where you have some many miles, there may be some merit to that and where you have staff who can in a reasonable time frame return that to service, but on a generation side, caution is required, from my perspective.
Q. I don't get the sense you're as "gung-ho" about this as perhaps some of the other people -
A. No, I have reservations about run to failure on generating plant that may affect--excuse me. That if you adopt that philosophy and embrace it, embrace it too much on generating plant, you may affect the forced outage rates and therefore affect timing. You know, we

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think that what we're doing right now is consistent with most of the Canadian utilities and we are striving to maintain those reliability numbers. If you run to failure and you, if over time affect our forced outage rates, then you will affect our overall asset performance and may affect timing of new plant.
Q. But reliability centred maintenance is not really intended to be a run to failure, is it, surely not?
A. It is one aspect of RCM. It is one aspect of RCM.
Q. We'll explore that perhaps a little more with Mr. Martin. Can I take you to WW-2, which is the July--sorry, June 30th quarterly report, to page 3 of that? A little bit--no. Should be page 3. I think you got to go a little bit further. Next page over, Mr. O'Reilly. There we go. In the area dealing with net operations, and there's a question that arises about the maintenance. There was a breakdown page that we had which is U-1, I believe, which provides a breakdown of that. Perhaps we could put that up? Yes, there we go. And

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the systems equipment maintenance is down for Hydro generally from 7 million 8 in the forecast to 6 million 2. And I'm wondering if you can shed any light on the reasons for that up to the end of June?
A. Yes. The primary driver or the primary reason for that is mostly timing, and particularly with respect to our Hydro--I'm sorry, Holyrood thermal plant. We basically have partner agreements in place with the, well, three actual vendors, and one particular vendor is the work is being done but his timing of bills is good for us and bad for him, from my perspective. He doesn't get his bills in on time, but it's mostly timing delay.
Q. Is it that the work is not done or that the -
A. No, no.
Q. - that the invoicing is not in?
A. The invoicing is not in. The work has been done.
Q. Oh, I see. So it does not -
A. It's just timing.
Q. It does not reflect a question of timing of the performance of the actual maintenance?
A. No. There were some exceptional items to be

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done in Holyrood, but the primary reasons for the large difference in the actual forecast, I'm sorry, the actual versus forecast is primarily the delay in the vendor submitting their bills and invoices to Newfoundland Hydro.
Q. Okay. Now, I understand in 2003 there was a major turbine overhaul for unit No. 1 at Holyrood?
A. Yes, that is correct.
Q. Without getting into a lot of technical detail, what's involved in that and would that improve the life of the unit?
A. Each year we do major overhauls of the boiler and then--and we do a minor overhaul of the turbines. Every six years, that's the present practice, that we--which used to be four years, we do a major turbine overhaul, which means that you basically tear apart the turbine, you remove the rotor, you check all the blades for any damage or corrosion and you fix, you fix what's broken. It wouldn't necessarily be life extension, but if you didn't do it, you would definitely have a shortening of the useful life of the machine.

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MR. HAYNES:
And, you know, we look for cracking on turbine blades, which eventually may fail and we replace those. We check the condition of the generator, the winding, and we--and often times we end up doing more work than we may have had in the plan because of that, because you're actually opening up something that operates at 1000 degrees and 1000 PSI that you haven't seen for six years.
Q. And that takes place every six years and the 2003 cost is about a million dollars, correct?
A. The additional cost is approximately a million dollars over the -
Q. Okay. And but you said that, well, if you didn't do this, the life would certainly be shortened. Does that not, as a corollary, mean that the life is extended by doing the overhaul?
A. That is a normal practice for any steam turbine operator to do a major overhaul at some periodic interval which may vary with use or their experience. And I guess it's--if you didn't maintain it, you would deteriorate the life. I'm not prepared to say that we're

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actually extending the useful life of the asset, but I have no, I have no reason to believe that we will not get another 20 plus, 30 years from the turbine itself.
Q. And what would have been the original life expectancy of the turbine?
A. Typically steam turbines are expected to operate about 30 years. However, we do have some other factors which affect our expected life, basically the fact that we do not operate that particular plant at 75 percent capacity or capability throughout the year, so there is some additional useful life. And we anticipate a 20/20 is a non-issue and in all likelihood we will be able to get beyond that with some reinvestment of capital over time.
Q. Right. So if--and unit, this was unit No. 1, that would have come into service when?
A. 1970, possibly.
Q. Right. So in the ordinary course of events that would have already exceeded its useful life, so but for these six year overhauls--these six year overhauls extend that life out further, is that not essentially the case?
A. I think the six year overhauls ensure that we

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will actually get there. I think one of the biggest factors in getting beyond the 30 year life is the fact that our operating factor since year one would not have been 75 percent, it would have been something less.
Q. Yeah. Now, there are other projects that are major projects in 2004 which are in the numbers, a heap tracing refurbishment for about $203,000?
A. Yes.
Q. And what's involved in that?
A. Primarily that is the fuel lines from the, I'm not sure which section, it would be from the marine dock to the--the marine dock to the oil storage tanks. And two of those tanks are original, the same age as the original units and two tanks were built in 1979, '80. So over the period of time there's been a deterioration in the insulation and in the heat tracing, so basically we are just basically overhauling, if you will, and replacing what has been worn out.
Q. So that's renewing the insulation on these systems?
A. And the heat tracing equipment itself.

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Q. And the heat tracing?
A. Yes.
Q. And that would be a betterment or an improvement to those from their current condition?
A. It's to ensure that we can, that we can move oil. Bunker C obviously in the cold temperatures doesn't flow very well so we have to keep it heated. So it doesn't necessarily--it doesn't preserve the life of the pipes in the sense of, you know, reducing corrosion or whatever from any major sense. It's more to just maintain the operating capability that was designed initially.
Q. And you have fuel oil tank cleaning and repair for 665,000?
A. Yes.
Q. What's that in relation to?
A. That is the fuel oil storage tanks. We're not contemplating any replacement of any steal of consequence. It's to look at the condition of the roof, to repair any pits that are there, to apply a protective coating, ie, paint, to drain the tank, to do non-destructive testing of the wells and so on to ensure we do not end

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MR. HAYNES:
up with an oil spill or leak.
Q. And you've got an asbestos abatement program. I take it that's to remove asbestos from some area for 175,000?
A. Yes.
Q. Where is that coming out of?
(12:00 p.m.)
A. Primarily it's units No. 1 and 2 which were the original plant. There's some small amounts of asbestos that was installed on Unit No. 3 mostly through repairs done over time and it's some--$175,000 is, I would suggest, the minimum amount that we see at this point in time. And over a period of years we would endeavour to remove most of the asbestos from the plant.
Q. And you've got a roof replacement for 215,000?
A. Yes.
Q. Where is that roof?
A. It's in the powerhouse in one of the--it's a section, it's the replacement of a section of the roof.
Q. And that part of the roof is simply being replaced?

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A. Yes. You know, it's basically a pitch and gravel roof which over a period of 15 to 20 years often require considerable maintenance. So it'll be just -
Q. But in this case, I take it, it's more than just a quick patch, it's actually a replacement job?
A. Of a section of the roof, yes.
Q. Right. And the last one I wanted to ask you about was fire protection purging valves relocation for $200,000?
A. Yes.
Q. Where is that? I take it there are new valves being installed?
A. No, it's not new valves; it's actually a relocation. And that was a strong recommendation of our underwriters for some years. And right now the turbine generators of Holyrood are cooled with hydrogen gas, all three are. And I guess experience has shown in other facilities and so on that obviously if it's a failure, it's a fairly volatile and explosive gas. And their recommendation was to move the purging valves from the second floor, which is basically down below the

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operating deck where the operators are up where they're more readily available to the operator in the case of emergency so he can actually isolate and shut off the hydrogen gas to isolate the system.
Q. All of the items that we just talked about in 2004 are in as operating expense as opposed to capital expense, and the 2003 major turbine overhaul, that in fact, was in as a 2003 operating expense as opposed to a capital item. Can I suggest to you, Mr. Haynes, that some of these items, in particular, the overhaul, the roof replacement, the heat tracing replacement and some of these other ones would, in fact, be more appropriately capitalized?
A. To date Hydro has treated most of those costs as operating costs because there was no significant life extension. We've had some discussions, obviously, with the controllers on and some decisions whether they should be operating or capital, but to date we have considered these to be, you know, operating costs because it's particularly in Holyrood, it's--that is this year. Next year it'll be a

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host of other things with such a complex operation. We have not capitalized that.
Q. Okay. Can I take you to NP-249? This asks about Hydro's guidelines for capitalizing. And the answer is, "Overhauls or major repairs would not normally be capitalized unless considered as a replacement or betterment of a unit or portion of a unit of property. And subject to Board approval the cost of major extraordinary repairs are recorded as deferred charges and amortized on the straight line method over five years." For example, the roof replacement we looked at is clearly a replacement of a portion of a unit, is it not?
A. The portion of the roof, yes.
Q. So why wouldn't that be capitalized within that guideline that you've got there?
A. None of the particular projects that we have in the operating budget for Holyrood we actually propose to treat that way. Usually on a recurring basis each and every year there are a number of these aspects in Holyrood. The heat tracing was a part of a multi-year program, and the roof replacement, I don't recall that as being a multi-year program, but

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MR. HAYNES:

I would not be shocked to find that next year or the year after we may find a comparable item. So over a period of time it kind of -

Q. But some capital projects do go on over a number of years, both big ones and -

A. Oh, yes.

Q. - small ones. And take the heat tracing refurbishment or replacement which again would be a replacement that takes place, I would suggest to you, of a capital nature?

A. We haven't taken that approach for some of the systems at Holyrood. We've treated those as operation costs and I'm -

Q. But then it goes into -

A. And I'm not sure what the depreciation -

Q. But then it goes into the test year expense for which for customers and ratepayers have to pay as opposed to having to having it capitalized?

A. And if you had it in a capital we would earn for a long number of years, which would be more onerous on the ratepayer.

Q. Yes. But there's a question of balance in there. And that comes to the second part of

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it, "Subject to Board approval". Has Hydro requested the Board to deal with any of these items over an extended period of time, either by putting them into capital or having them dealt with as amortized over five years?

A. No, not to my knowledge, no, we have not in recent times taken that approach.

Q. Okay. Can I take you to one last question on maintenance to Mr. Brushett's '03 report at page 42, and to the table at the--sorry. If I said '02, Mr. O'Reilly, I meant to say '03, page 42. There we go. This deals with maintenance expenses. And you see production there?

A. Yes.

Q. Which would be your department. In '02 we had 7.7 or 7.8 million whereas forecast '04 is 9.1 million, which is an increase of about 1. 3 million, many of which are the projects that we just talked about. And keeping in mind the significant increase of 1.3 million over ' 02 to '04, does that shed any light on whether these should be treated as capital or operational?

A. I think you can equally go back to 2001 where

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it was $9.2 million. And 2002 we did cancel some projects, you know, in striving to--or deferred some projects and cancelled some to some considerable time later to try to meet the direction of the PUB on our productivity allowance and our bottom line. But the2002 test year was--the 2003 test year--I'm sorry. 2003 test year included a major overhaul. 2004 does not have a major overhaul, but there are other projects that are in there. And certainly on a go forward basis we will try as best we can to levelize that. And that's been the subject of, I guess, some discussion for some time. It's very difficult to levelize the cost of Holyrood because of the nature of the beast. But--and I fully expect in 2005 it'll be in the same order of magnitude of numbers.

Q. A couple of questions just to close out with respect to the IT area.

A. Yes.

Q. And can we have a look at NP-259? And if we go over to the attached schedule, we look at the production division, this is travel and conference, the amount for IT is dramatically

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in excess as you go along through 2002 travel and conferences than any of the other departments?

A. Yes.

Q. Can you explain to us why that would be the case and what efforts are in place, if anything, to control those items?

A. For both categories or?

Q. You have both travel and conferences, and as I look across the line both substantially exceed the amounts for any of your other departments. The first question, why is that the case, and the second part of the question is what is being done to control it?

A. As I mentioned, I believe, when Mr. Browne was questioning on this, on the travel components, the IS and T department, you know, maybe I should go back and compare it to hydro generation. Hydro generation has a few extra people, but they basically maintain seven or eight specific sites, different hydro plants. The IS and T section maintain all the IT infrastructure across the system, the VHF communications, the microwave system, so inherently there's a bit more travel to an

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MR. HAYNES:
excess of 100 particular sites, so there is more travel. On the conference budget, there has been money allocated for attending various technical conferences whereby it's--whereby there is value added in the sense of bringing back what other IT organizations are doing, what other utilities are doing, and that was part of the seventy-one, five. In 2003 it basically was 25 and a half. And if I recall correctly, in our re-file there will be a change in the seventy-one, five, down to comparable levels to last year. But in keeping up with the technology and the trends and understanding what people are doing and opportunities for improvement, conferences are a good place to attain that information.

Q. But I thought travel and IT was one of the areas that you had told us earlier that there were some potential for savings now as you get the ability to control and rectify some of these systems from St. John's?

A. Yes, and to -

Q. It's about travel.

A. - and the 2004 forecast, from 2003, is

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significantly down on travel from 220 to--well, from 218 or 219 to 184.

Q. But it's still -

A. It's still high.

Q. - it's still up over 166 in 2002.

A. Yes. But we have added a VHF radio--I'm sorry, we have added an additional microwave systems, the interconnecting loop between Sunnyside and Grand Falls area and added a facility which requires obviously personnel to maintain and review.

Q. If I take you to the Grant Thornton '02 report, and I do mean '02 this time, at page 24, and you'll see this breakdown, and there's an item in there for EXP Advisory Service, which I understand is essentially another name for the Gartner Group research people, see that?

A. I see EXP, yes.

Q. Okay. And if you go to NP-257, you'll see Gartner Group for the years '01, '03 and '04, and the numbers, in round figures, about 104,000 for '01, 138 for '02, 138 for '03 and 145. Can you explain to us what this continuing item is for?

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A. We have subscribed to Gartner, as has dozens of other utilities and companies, both in Newfoundland and otherwise, for their advisory services with respect to IT, and you know, a lot of other--the Newfoundland Government, health care, Newfoundland Tel, New Brunswick Power. It's basically a retainer that we pay. We subscribe to certain services from Gartner to aid us in ensuring that we are getting the best value for our money spent on all our IT, in order for us to provide more or better services at the same or reduced cost. It's a common industry--it's a well-known consulting group in the IT area and subscribed to by many utilities and other companies.

Q. But in addition to that, the next item down is "Information Technology Infrastructure Library" and that also is a recurring item that if you go through the numbers, in 2002, you've got 259, 2003 66 and 2004 76. What's included in that item, since you've already got Gartner?

A. ITIL, they are not--ITIL is an information technology infrastructure library, originally put together by the British government and

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accepted by virtually all of the--it's a book, not a book necessarily, but it is a list or a structure of IT best practices which we subscribe to. When we started doing this and looking at this, and I would suggest that Gartner was probably a part of that, who may have been a part of that particular--of us actually buying into that methodology. We retained the company to help us set up some of the aspects and over a period of time, that will diminish. What we acquired from the ITIL consultant that we had hired was basically to come in and work with us to set up some of these particular systems so that we can learn and set up future ones ourselves at a much reduced cost.

Q. So there was a -

A. - basically, it's a list or a whole raft of best practices in the IT area.

Q. So a consultant came in and set this up for you?

A. Helped us kick start, if you will, that philosophy and where we can use those particular tools and gain by it.

Q. Do you know how much that consultant cost?

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MR. HAYNES:
A. I think that's in the numbers that you had there a minute ago, in 2002, I believe, of-- and they set up the Help Desk process and a couple of other -
Q. So that's in the 259,000 in the 2002 year, is it?
A. Yes. My recollection is that was the initial come in and get it going. There would be reduced costs after that and it would diminish.
Q. So the ongoing cost then is in the order of-- well, in 2004, you've got it budgeted for $76,000.
A. In 2004, yes.
Q. Okay. If you go back to the Grant Thornton '02 report, one of the questions I'd asked Mr. Roberts, as Grant Thornton dealt with significant items, there was about $900,000 left over and I asked what was included in that, and one of the items that Mr. Roberts referred to was 224,000 for additional information technology items covering assistance that was required relative to the intranet document management security. Does

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that have anything to do with your department?
A. It would be through the IS&T department.
Q. Goes through IST. What was that about?
A. Can you just repeat the -
Q. It's Mr. Roberts, if you want, the precise language, October 16th '03, page 121. Put it on the screen, if you like. And it's line, about 24. No, gone too far, top block. There you go. If you scroll down a little bit or scroll, take it back up to the top a bit, Mr.- -there we go, we get the top of the next page. The bottom of page 121, "there was 224 for additional information technology items covering assistance that were required relative to our intranet document management security."
A. I don't recall specifically, but with respect to the intranet that we have deployed, we pay a fair bit of attention to security and to ensure that people can't, you know, hack our sites and so on, but I don't -
Q. Don't know what that is?
A. - recall specifically, but I would suggest that it's related to that aspect of it.
Q. And then there was another 141,000 associated

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with Holyrood and included such things as utilization of services of a chemical consultant, et cetera, read it there. What did that relate to?
A. In Holyrood, it's a thermal plant. You could also look at it as a chemical facility, I guess, as well. We have to pay quite a bit of attention to our water that we use in the steam processes. It's demineralized water and we retained, I think it was Dearborn Chemicals at that time, to review our chemical treatment of the water. If we didn't do that and our water quality condition dissipated, then basically we would have more fouling of boiler tubes and less efficiency and so on. The other aspect is that at the Holyrood facility, with respect to the landfill, we had a certified landfill. We recover all water that comes over that. We test it to ensure we're not leaking anything into the environment, and as well, our lab technicians out there are certified through, I forget the particular branch, but that's a requirement of our certification with Government to maintain that self-controllability that our chemical

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technologists are basically certified by, I think, CAEL, C-A-E-L, I believe. So those are costs related to our water quality, keeping up our certification of the technicians and so on.
Q. Thank you, Mr. Haynes. Those are all my questions. Thank you for your patience.
A. You're welcome.
CHAIRMAN:
Q. Thank you, Mr. Kelly. Mr. Haynes, we'll move now to the Industrial Customers. Good afternoon, Mr. Hutchings.
HUTCHINGS Q.C.:
Q. Thank you, Mr. Chair. Just as I had mentioned earlier, Mr. Seviour will be participating in this cross-examination as well. He will be dealing with issues related to plant assignment, but I'll start off and deal with the balance of the issues that Mr. Haynes addresses in his evidence. Good afternoon, Mr. Haynes.
A. Good day.
Q. Mr. Haynes, I want to begin with some brief questions on the area of hydrology. In your evidence at page 28, and there were some

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HUTCHINGS, Q.C.:
questions addressed to you earlier in this connection, 28, page 28. You were asked earlier, I think, in connection with lines 11 through 13 on that page, about the power and energy analysis that you did for Granite Canal. Can you just explain for us how the addition of the Granite Canal plant affects or is affected by the inflows that we have spoken of or does Granite Canal make any difference to the actual water inflows in the Bay d'Espoir system?

A. No, it doesn't. There was no change in the watershed area, the drainage area, with respect to the Bay d'Espoir plants. So there was no--there would be nothing of any consequence. There may be some inter-reservoir flows that may be affected, but there would be no gross change or no overall change.

Q. Okay. So is there a separate specific reservoir that relates to Granite Canal?

A. Basically it's Granite Lake.

Q. Yes.

A. We did erect the--when Bay d'Espoir was built

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initially, there was a Granite Canal which was basically blasted out of rock to drain the water from Granite Lake down to Maelpaeg, and all we did really with respect to Granite Canal is we basically put a bypass structure there and we built a canal and a small intake for the Granite Canal project. So there's no--there may be some small impacts or impacts on the operating level of Granite Canal, but there's nothing out of the ordinary.

Q. Okay. So can you just explain for us then essentially the flows of water that we're talking about in the Bay d'Espoir watershed? You're leaving me with the impression that this water is in fact used by several different plants over and over and I just want to make sure that I'm getting the right understanding of that.

A. I don't have a mental picture of all the reservoirs in the Bay d'Espoir area, but I'll start from the sea level and go back.

Q. Okay.

A. Our Bay d'Espoir plant is built basically at not tide water, but close to it, and that would be the lowest hydraulic head plant that

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we have. As you go back up country, you get into Upper Salmon and Upper Salmon takes advantage of a natural elevation difference between a couple of reservoirs. Granite Canal does the same thing, as would Island Pond, if and when we ever build that. So what we've done is Granite Canal would be the--the water that comes from the furthest reaches of the reservoir is turbined at Granite Canal. It will eventually be turbined at Upper Salmon, and finally, it's used a third time over at Bay d'Espoir. I don't know if that explains your -

Q. Okay. Yes, I think that's consistent with the impression that I was getting. So in terms of the hydrology issues that were left to be dealt with and have been addressed in the Acres report now, the presence or absence of Granite Canal really doesn't impact that. It's just that we are able to get an additional 224 gigawatt hours of electricity out of the same water?

(12:23 p.m.)

A. The 224 should not change as a result of any consequence with respect to this. 224 is the

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average estimated capability and 216 is the firm.

Q. Okay. I noted that one of the recommendations made by Acres, and it's quoted by you on page 29 of your evidence, references the fact that the system simulation models usually require a common start date for all inflow sequences, data from the earlier years of some inflow sequences would have to be cut off. I take it, again, Granite Canal doesn't impact that process at all, does it?

A. No, it shouldn't because the water regime in the Bay d'Espoir area, it's all part of the same watershed. So there may be some little--some small distribution factors between the various things, but the actual water that's discharged at Bay d'Espoir will not change.

Q. Okay. If we can move then to your Schedule 4, which you discussed a bit, I think, with Mr. Kelly, and it's a graph of total system energy storage. Am I correct in assuming that this particular line is not what you technically refer to or use operationally as a guide curve, is it?

A. It's what guides us on our annual operation

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MR. HAYNES:
for the reservoirs, and I guess in describing that yesterday, I may have misrepresented a little bit the summer increase in June and July. I think I had talked about snow melt and so on. That is more related to our peak maximum flood. When the probability of a flood event at that time of the year is actually lower, so we can actually surcharge some of the reservoirs, but it is a--this is a system and each particular reservoir may have a guide curve that talks about, for Granite Canal or say for Cat Arm. This is the overall, you know, energy and storage that we have.

Q. Yes, and that's what I was getting to. This is a cumulative graph which shows all of your systems, even if they're not connected to one another?

A. Yes.

Q. Yes, okay, all right. So presumably for each of your reservoirs and at least for each of your generating plants, there would be a guide curve and that would be what would be used in the actual operation of your facilities?

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A. It would be a factor in the individual plant operation.

Q. Yes, yes. But I mean, I'm assuming that you produced this graph in this form essentially for illustration purposes, in terms of showing the total system energy storage as opposed to giving us something that your operators would use on a day-by-day basis to actually manage and control the systems?

A. This is used by our operations people. Basically when you look at the, whatever colour that is, I'm sorry, the purplish line, the pink line, I'll call it, that is where we stand with respect to meeting our firm requirements. So when we are below that line, we would be stressing production out of Holyrood. When we're above that line, then, you know, we could back off a little bit on our expectations of Holyrood. So we would try to stay, on a whole, above that green line. So it is used. That is something that I would look at periodically in my office to see how we're doing. It's the subject of a daily report.

Q. Yes. But your purple line there is a amalgam

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of the operations of a number of watersheds, and I mean, theoretically, Cat Arm, for instance, could be pushing the limits of its maximum storage, whereas Bay d'Espoir might be low, so that, you know, you'd be operating Cat Arm in a different way than you would be the Bay d'Espoir watershed, if that was the case?

A. Yes, that's correct, and that obviously depends on the hydraulic conditions on the Cat Arm reservoir versus Bay d'Espoir, et cetera.

Q. Right, okay.

A. Often times different.

Q. Yes. So you manage each reservoir in itself as opposed to specifically managing--I mean, obviously you manage the whole system, but you have to look at the individual guide curves in order to determine what usage you're going to make of a particular facility, correct?

A. Yes, we look at each facility and, as well, we look at the whole.

Q. Okay. Now you spoke with Mr. Kelly on this yesterday, and at page 160 of transcript of October the 20th, at line 10. You're discussing the different lines that appear on this particular graph and at line 10, you're

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asked "so the red line at the top is your perfect world, so to speak?" and you say "the ideal world, yes." The top red line represents, as indicated, the maximum operating level? Is that correct?

A. Above that line, we will be in a spilling water. That is the maximum storage capability of the reservoir system.

Q. Yes, okay. But let's assume that this graph, instead of representing the entire system, was representing a single reservoir system, and let's use Cat Arm, because Cat Arm is easier separate from all the others. In managing your system, would you try to get to the red line or would you try to get to the green line?

A. In any particular reservoir, you would--if you're at the red line, you're probably in a--you are risking spill, accepting a higher risk of spill, in a single reservoir. You would try to manage the whole. Obviously it don't have to be the same, but you know, you would have some ban that you would operate and I don't know what the actual number is in the operating area, but I don't think that you

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MR. HAYNES:
would strive to maintain any operating plant to be at 90 percent full and another one to be at 30. You would have some range of realism, tempered by the fact that you would try to minimize your use of oil.
Q. Yes. And when you're on the green line, essentially you're maximizing your use of water, aren't you?
A. That's correct.
Q. Okay. And if you had perfect foresight and you knew that you were going to get sufficient rainfall and other events to keep you on that green line, you'd stay on the green line forever, would you not?
A. That would protect our firm, which is our minimum criteria, yes.
Q. Yes, okay. So I'm pursuing this because it would seem to me that the red line wasn't actually the perfect world, that the green line was, and I'm wondering if you can comment on that?
A. Well, my comment in respect to the perfect world, I guess, is that if we had full supply reservoirs and we're meeting our load, we

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would have a lot of rain and we would be doing both. You know, you operate within those bounds, as system conditions dictate. If you could provide all our load to all our customers with no oil use and stay up close to the red line, we have tons of water, it wouldn't be an issue.
Q. Yes.
A. But that's not reality.
Q. No. But I mean, with our system as it is configured now, other than a couple of months in the summer, we can't provide the complete load hydraulically, correct?
A. Most summers we can shut down most all machines at Holyrood. That's not--you know, it may be for three weeks. It may be for four weeks, maybe one machine running, or no machines running, but it depends on the demand of the system, and particularly the hydrology that we've experienced.
(12:32 p.m.)
Q. Yes. But given that we are, most of the time, pumping at least some thermal energy into the system, our goal should be to keep as close to the green line as we can get? Is that

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correct?
A. I wouldn't say, not on a monthly basis, but on an annual basis, if you come into the--you're on the green line and you go out of the--you're close to the green line and you're doing well, but at any particular month in the period, you would built up hydraulic resources and you would be above the green line, anticipation of freeze up or the fact that you're going to delay starting a Holyrood plant. So it's not a--I don't think that the--it would be a target to stay on the green line 365 days a year. You would certainly build up a reservoir situation beyond what would meet your firm, knowing that you are going to come down as you do there, for instance, in 2002. We were up to about two terawatt hours in June and then presumably Holyrood shut down at that time frame and when Holyrood shut down, we quickly came back to near the green line. So it's a--you know, there's no standard answer. You can certainly wrap up between those lines and still maintain overall effectiveness of Holyrood and the hydraulic resources.

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Q. But again, if we look at the slope of the green line itself, what factors are incorporated into where that green line happens to be at any particular point during the year?
A. I think one is the average expected precipitation on a monthly basis will be a factor, and probably a fairly key factor. We basically plan the system based on average.
Q. Yes.
A. And the average inflows. I say precipitation, really what we actually measure is the inflows, not the precip per se.
Q. So the minimum energy storage targets that you've established are based on these three worst years scenario?
A. I gather it's about three and a half to four years, 1958 to '61, that time frame is the firm sequence which we've planned for.
Q. Yes, okay. I guess my question might perhaps best be answered by having you explain for us why that green line isn't simply a horizontal line going across here.
A. I won't pretend to know all the details that go into that, but it is not sort of similar to

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MR. HAYNES:
the red line in the fact that, you know, that line is based on an average precipitation or snow melt--I'm sorry, inflows to the reservoir and so it does move. In the summer months, our average precipitation is down and the line occasionally comes up a little bit because we would not anticipate a major influx of rain, you know, for instance, in the middle of June. We would not anticipate, on average, that we would have major rainfall. So it's primarily driven by the inflow averages that have been built over time.

Q. Okay. Does that green line change from year to year?

A. Yes, it does. The averages change over a period of time. There was an RFI filed with several sequences and there is some, you know, change from year to year. I don't recall which RFI it was, but there was an RFI filed with a series of charts from probably three or four years, and there are some changes in the green line, based on average, where the water is and the situation at the time.

Q. Okay. So can you tell me, aside from that

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series of lowest water years that we've spoken of from the 1950s, what are the other inputs into that green line? I mean, if, in fact, it was just the lowest water years, then presumably it would be a constant line. It wouldn't change year over year?

A. I don't know all the factors that go into it, but even if it was the average water, it's based on the monthly average inflow. So it would not be a flat line in any case.

Q. No, no, I'm not saying a flat line, but it would be the same line this year as it was last year, if it was based upon three or four years in the 1950s, if that was the only input?

A. I'm not sure of the answer. I don't know.

Q. Okay. Can you try to get an answer for me on that?

A. I can try to clarify a bit more detail. (Undertaking)

Q. Okay. Thanks. Arising also out of your discussion with Mr. Kelly on that subject, is it fair to characterize your operation of the hydraulic and the thermal generating capacity as basically a trade off between oil and

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water?

A. I don't think trade off is an appropriate description. What we try to do is optimize the hydro-thermal mix to reduce the overall cost to the rate payer, to the customers.

Q. Yes. As you discussed with Mr. Kelly, given that the marginal source of energy is, for all intents and purposes, always Holyrood, the time of year at which you generate doesn't affect your costs, your marginal cost on the system, does it?

A. In the short term, I guess I say that the marginal cost in the short term is Holyrood, but as you approach--you know, when you start to run out of that capacity, our marginal cost may be, you know, a combination of next source and so on. So it's not the--the marginal cost in the long run is not necessarily Holyrood. It may be the next source or some combination. But in the context of on a short time, short-term horizon, if we're not spilling water or not risking spilling water, any energy that we do not--any energy, for instance, in July that we do not generate by thermal means because we're using our hydrology, we would generate

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later in the year. I mean, at the end of the year, we have X number of terawatt hours, 8 point, 8400 or whatever it is, gigawatt hours to supply, and if we're not in a--we do not plan for spill per se, any of the energy that's saved or produced hydraulically will be replaced by thermal in the short term. Eventually a new source will be required.

Q. Effectively, you could choose, at any point during the year, when there was no fear of spilling, to burn fuel to basically add water to your reservoirs, correct?

A. Yes, and we do take that into consideration and we do--you know, when we are particularly below the green line, we have a desire to get Holyrood back on sooner so we can get above that line to assure that we can meet our firm target.

Q. I'm more interested, I guess, in the times when you're between the green line and the red line. You're above your target green line water level, if you wish, but there is no fear of spilling. And referring to your fuel purchase contract which allows you a certain amount of purchases on the spot market, have

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HUTCHINGS, Q.C.:
you considered spot market purchases during the summer periods in order to build water reserves for the winter period?
A. Not of late. We have not looked at it. I mean, it's an option that we have, to look at the spot market to do that, but we have not actually done that in recent times.
Q. What forecast pricing information do you get from PIRA on a regular basis through the year which might allow you to evaluate that possibility?
A. I think we get a PIRA forecast, I believe it's on the quarter, and basically, in the short term, they give us a monthly forecast, and then in the long term, they give us an annual number, you know. For 2004 right now, it'll be just a--I'm sorry, 2005, it'll be a single number. But it's a forecast. That is a--if we were guessing the market, I guess, we could do that. We have not done that in a considerable amount of time and really, our fuel purchase contract that we have in place right now, as mentioned in our thing, is basically we pay on monthly average prices.

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So when the market spikes up or spikes down, we don't actually pay those prices. We pay an average monthly price, which we think is a good compromise of gaming it, and you can win or lose by doing that.
Q. No, I understand that, but if you're in a situation in the summer when the forecast for the fall when you would normally be making your fuel purchases is that there's going to be an increase in the prices, what extra cost is there to you, other than a carrying cost perhaps, of making a spot purchase at what is forecast to be a lower price than you're going to pay in the fall, and using that energy to fill your reservoirs basically.
A. There is nothing to prevent us from doing that, it's not an option that we've chosen to be one that gives us great comfort that we are going to actually gain at the end of the day. It all depends on where the market goes. We could do that, if we were to order a shipment of oil for such and such a date, and we get that price the next month, it could be up or down. I mean, the forecast now for 2003 is that actually in October, it will be down

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again, so I mean, it's so volatile that I guess it's, as Risk Advisory had said in our, in the report that we had done, that it was very unlikely that we could actually beat the market in a sustained fashion.
Q. No, no, I'm not speaking about their notion of beating the market in a sustained fashion, it's simply a question of timing purchases, given that you know that at some point during the year you're going to burn that fuel in any event. Do I take it that you haven't looked at that possibility?
A. There are two other factors there, one is that I guess in the summertime Holyrood is under a fair bit of maintenance activity, and so you really don't have the opportunity to do too much of that, obviously there's some; the other thing is that in the middle of winter and December, we will be operating three machines anyway and we would try to optimize and increase the loading to as high as reasonably possible to maximize our conversion factor. If you were to run up against the red line, if you will, and then in the wintertime you would have to, you know, keep Holyrood

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going at, say 100 megawatts of average loading, we would deteriorate and I'm sure, I would suggest we would lose--we could lose any benefit that we gained by buying on the spot market, not to say that we can't do it, but--and we do have the provision to do that, but it's what we consider a little bit of risky business. It's a gamble and we have chosen not to take that approach.
Q. Looking at where your actual total system energy storage was at the end of 2002, you were some significant different distance below your green guideline, correct?
(12:45 a.m.)
A. I'm not--yeah, on that chart, I'm not quite sure what the previous graph, the green line was. I don't remember which RFI that was, but on that particular--going in on January 1, we were below the--where we would like to have been, primarily based on the heavy demand put on Holyrood during the year--I'm sorry, the low hydraulic inflows during the year.
Q. So does that fact constrain the amount of energy you can produce hydraulically?
A. Can you repeat that?

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HUTCHINGS, Q.C.:
Q. Does the fact that you are below your guide curve, the green line, shall we say, constrain the amount of energy that you can produce hydraulically at that point?
A. No, I don't think on a weekly or a daily basis it would. I think what it really says is that if we were to start our firm sequence on January 1 of 2003 and we actually had a repeat of a 1958 to 61 event, we would have some difficulty meeting our energy requirements based on our firm plants.
Q. Okay, so when your peak arrives in January--well, when it arrived, presumably in January of 2003, you were maximizing hydraulic output in any event, is that correct?
A. Yes, we would have on a short--you know, the peak that we meet with hydraulic plants versus the overall long-term energy production are disjointed. As long as we have water at the intake, then we can max out any hydraulic machine to its capability. The lack of water means that you will not be able to do that for 60 percent of the year, it may be 50 percent of the year if your inflows are 10 percent

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below what you would normally expect.
Q. And thereby, you take the risk that you're not coming into the driest cycle ever?
A. Well yes, I guess in a way you could say that, but, you know, we do have, if you were in a pinch you could obviously use gas turbines to provide some energy if you're just a little bit off that base, although it's very expensive and prohibitive to do.
Q. But I mean, your gas turbines are built into your firm capacity, correct?
A. They're built in on a megawatt, but we do not plan for any significant energy production from the gas turbines. They're not considered to be firm plant.
Q. While we're on the subject of firm energy, I wanted to ask you a couple of questions that related to the wind project down on the Burin Peninsula. As I understand it, in the documentation that's been filed before the Board here, there is nothing in the Cost of Service or any of the related material that will go into producing rates at the end of this process that affect or is affected by the wind project, is that correct?

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A. There is nothing in the 2004 Cost of Service to reflect any purchase cost for the wind. The contracts are under negotiation with Newind, as well as with the Federal Government under the GPPI Program to, and we are hoping to get the best we can from the Federal program to mitigate some of that cost.
Q. So in terms of what the Board has to do here, it's going to set rates based on a 2004 test year as if that wind project didn't exist?
A. If the wind project?
Q. As if the wind project didn't exist.
A. It's not in the 2004 Cost of Service at this point in time.
Q. You gave us some information yesterday in your direct examination on the wind project, could you just remind us of the capacity, you're talking 25 megawatts, I believe?
A. The proposed project right now is in the order of about 38 wind turbines, 25 megawatt capacity and approximately 96 gigawatt hours of energy, average energy capability.
Q. Okay, and assuming that project comes on stream, will you regard that as being firm capacity?

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A. There is a--when you look at any hydro plant, there is a forced outage rate or an availability figure assigned to it, and on a wind turbine, we did undertake a review of that and I just do not recall at the present time exactly how much we considered, but it is 25 megawatts that by and large will be there, the wind regime is very good. But obviously will not be there one hundred percent of the time; and nor in our planning do we consider all hydro plants, there's a forced outage rate, the repair time associated with it as well. It would be a little bit more for the winter, but it's a load capacity factor, I don't recall the numbers offhand.
Q. Okay, I believe you had some discussion yesterday which talked about the effect of the wind project on your LOLH calculation and will it or will it not have an effect if it comes about?
A. I don't recall exactly, I don't think we actually--I don't recall any question that we actually looked at what the impact would be, I don't think. It's treated somewhat like the star, from the point of view of its

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MR. HAYNES:
capability, it's basically take or pay. We buy when it's making energy. I don't recall that we actually did any analysis of LOLH, including the wind turbine in any RFI.
Q. Okay. Well without getting into a specific number then, would the introduction of the wind project as a matter of principle affect your LOLH calculation?
A. It's another 25 megawatts on the system and it would have impact. It would be 25 megawatts that we would assume would be there and it is there most of the year in some capacity or another, but it's not dispatchable in the same sense that the NUGS are not dispatchable.
Q. Okay, and you don't know what capability factor would be assigned to the wind project at this point?
A. I don't recall offhand, I'm sorry.
Q. So do you know or not whether the wind project would delay the violation of your LOLH guideline and if so, to what extent?
A. I believe we indicated before of approximately one year, the LOLH--I don't recall actually a question regarding that, off the top of my

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head, but I do recall we did say one year deferral of the LOLH with a 25 megawatt additional generation on the Burin Peninsula.
Q. And that, presumably, is inputting into that calculation something less than 25 megawatts as firm capacity?
A. No, I think that would be the 25 megawatts would be there, as assumed in that figure. But in the LOLH calculation, which is not just a straight mathematical thing, you have to consider the megawatt capacity, you have to consider the capacity factor and all of that goes into the equation, for the lack of a better word, to come up with that there. And I think it was a one-year deferral of the-- when we would actually be in trouble on the LOLH criteria.
Q. So in terms of your Table 8 and maybe we could put that up, Mr. O'Reilly at page 37. You're suggesting that instead of 2010 or 2011 when the capacity criterion would be violated, that would be 2012?
A. That's correct.
Q. Okay, and what about the energy balance issue?
A. I would assume that basically we'll have

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another 96 gigawatt hours per year, so it would have some impact on that number, but I don't know the specifics because you still have to consider the time and the capacity factors and so on. We would actually have to run that particular thing, but I would suggest it may be a year or so.
Q. Okay. On your current Table 8, there's a minor violation, I guess, of your energy balance criteria in 2009?
A. Yes.
Q. And there's a more significant one in 2010. If in fact your energy forecast increased by 96 gigawatt hours per year, it would in fact be 2011 before your energy balance criteria was violated?
A. I'm not sure if that's exactly right because the energy balance is based on a firm sequence, I'm not sure exactly how the wind was treated in that particular calculation, but I think a year or so would be an approximate number that we would, on a cursory nature, evaluate as being a reasonable approach.
Q. So would it be fair to say though, that with--

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if the wind project goes ahead, the time at which the demand criteria gets violated and the time at which the energy balance criteria gets violated tend to move a bit closer together?
A. It may and I guess what we had said previous is that it would see one year deferral in the addition of new plant to meet those needs.
Q. Okay. Are you aware of the practices of other utilities in terms of whether they regard wind power as being firm capacity?
A. Not immediately. I know that we have reviewed that with respect to other utilities and there is certainly--there is certainly some issues with respect to the integration of wind into a system if the numbers get too big with respect to regulation and that criteria. It is usually considered and I've read papers on that, but I'm not quite sure in the context right now. There is some practice in the industry how that's incorporated into capacity planning.
Q. So you have not, to date, incorporated the potential capacity from the wind power project into your near term capability requirements,

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HUTCHINGS, Q.C.:
is that fair?
A. No, nor have we put it into our--you know, it's not in the 2000 test year in any form.
Q. No, no, and that's quite properly so, and I mean, subject to the Order in Council in any event, but in terms of your long-term planning or near-term planning between now and 2012, you haven't incorporated the potential existence of the wind power into that scenario either, have you?
A. I'm sure that planning has looked at it, but we have not provided any information in any RFI to any details of that effect.
Q. Okay. At page 33 of your evidence, when you speak of the long-term planning forecast, I think that's 34, yes, okay, you're speaking of the long-term planning load forecast and at line 6 you say, "Hydro's current ten-year annual average load growth projection for the Island Interconnected System is 1.3 percent." Is that figure calculable from your Table 8 or how do you come up with the 1.3 percent?
A. I think you would have to go to the--just a second, I'm going to refer before I speak, I

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think you would have to go to one of the load forecast schedules, I believe, actually it doesn't go long term. I didn't actually calculate the number, but I presume Table 8 would be close to it, but I didn't actually calculate the figure.
Q. So you think that that figure should be calculable from Table 8?
A. Should be close.
Q. And when you say load growth projection, are you speaking peak or energy or both?
A. Typically that would be energy.
Q. Okay. There's a significant increase, obviously, in 2012 which you referred to in your evidence as relating to the Voisey's Bay Mineral Project Development. Can you tell us what the average load growth would be from 2003 to 2011 before the Voisey's Bay Project fits in?
(1:00 p.m.)
A. I cannot calculate that in my head, I'm sorry.
Q. Can you undertake to provide that for us? (Undertaking).
A. Yes, we will.
GREENE, Q.C.:

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Q. I wonder if Mr. Hutchings could repeat the question.
HUTCHINGS, Q.C.:
Q. I'd like to have the annual average load growth projection for the Island Interconnected System between 2003 and 2011, on the assumption that the ten-year one that is referred to at page 33 of Mr. Haynes' evidence is from 2003 to 2012.
Q. Mr. Haynes, I notice that one of the challenges you referred to in your direct evidence that Newfoundland and Labrador Hydro faces is the question of isolation. Did you feel better about being isolated in August of 2003?
A. We will survive the 2003. We're doing a much better job.
Q. So there are some advantages, actually, to being isolated, aren't there?
A. On days like that, yes.
Q. Yes, no question. All the trees in Ohio can fall and we're quite safe here.
A. Ice usually gets us.
Q. That's true. One other calculation that I wanted to review with you and you referred to

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it at page 138 of the transcript of yesterday, at lines 12 to 18, and that's the average annual energy for Holyrood, based on a 75 percent availability factor. And you gave the numbers of 466 megawatts times 8,760 hours in a year, times 75 percent. I did that calculation and I couldn't come up with the 2996 that is in your table. Is there something else we should be doing?
A. Can I ask how far off you were? It's actually 46 or 6 1/2 megawatts and somebody may have to count it for a leap year, I'm not sure, but -
Q. We ended up with a figure of 3061, as opposed to 2996.
A. That maybe the half megawatt, the actual net rating is 466.5 megawatts, is the net rating.
Q. Oh, I think that would make it worse, well then we get 3064.
A. Recalculate the number.
Q. Uh-hm?
A. I say I will get the number recalculated but that's fairly close.
Q. Yes. The 38 percent that you referred to, that is the capability basically from your thermal production, as opposed to the actual

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HUTCHINGS, Q.C.:
percentage of thermal that you would have in any given year, is that correct?
A. Which line are you referring to please? You said 38 percent?
Q. Yes. I think Mr. Wells referred, in his evidence, to 38 percent of the capacity of the system being thermal?
A. Yes, the 38 percent of Hydro's total capability, our own generation plus what we purchase from our NUGS is 37.6 percent. That's Holyrood, plus the gas turbines, the Hawke's Bay diesel, et cetera.
Q. Right, okay, but in terms of your actual production, you have never actually reached that number, have you, that percentage?
A. I can't say whether we have in any particular point in time with all the machines on, I would suggest that when we were meeting peak last year in 2002, we called upon Newfoundland Power as well to start their gas turbines, so we would have been fairly close of dispatching all plant that was not on maintenance or--to do that.
Q. Okay, could we bring up IC-151? Go to the

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table on the second page. This shows the actual production, as we understand it, on the Island Interconnected System from 1992 up through to 2002. And on calculations that we've done, I think in 2002 it looks like about 36.5 percent of your production was thermal, does that sound about right to you?
A. Yes, that's energy, that's not the number we were just speaking to a minute ago.
Q. Yes, that's energy, yes. And running down through the years, back to 1992, I think 1994 was probably the best year in the sense that only 13.4 percent of the energy was produced from your thermal plants on that--in that year? Does that look about right to you?
A. Yes, Holyrood was 770, that's a low year.
Q. Yes, and on our calculation, the average over the period that's shown there would be about 24.2 percent of your production being thermal. Does that figure sound generally correct to you?
A. I'll trust your math, that is correct, it's not surprising.
Q. Pardon me?
A. I said I'm not surprised by the number, I

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didn't check the numbers, I assume your math is correct.
Q. Yeah, okay. And can you tell us what your plan for 2004 calls for, in terms of energy production from Holyrood, what percentage would be thermal?
A. Yes, that's in Schedule 7, I believe. Maybe not Schedule 7--excuse me for a second while I find it.
Q. You're looking at the net production of 1790.15 gigawatt hours?
A. That sounds right.
Q. Okay. And have you calculated what percentage that is of your total?
A. I have not, no.
Q. Okay. I've done it a couple of different ways and I come up with numbers in the range of 23 to 26 percent. Does that sound about right to you?
A. I'm not surprised.
Q. Yeah, okay, all right. In doing these calculations, I assume and I think this is what you confirmed for Mr. Kelly earlier, that you take your anticipated average production from your hydraulic sources and your

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anticipated average purchases from your power purchase contracts and then deduct that from the total required, and the balance becomes your anticipated production at Holyrood, is that correct?
A. That's more or less correct, yes.
Q. I want to speak a little, Mr. Haynes, with you about the short-term load forecasts and how you handle those. I think we've had described here previously the process whereby you obtain load forecasts from each of the Industrial Customers and from Newfoundland Power, and add to that your own forecast for Hydro Rural for the purpose of determining what loads you're likely to have to meet in the test year, is that correct?
A. That's correct.
Q. Okay. Can you describe for us how you deal with this raw data that is provided to you from Newfoundland Power and the Industrial Customers, whether--what scrutiny it undergoes or whether it's questioned or what happens to it?
A. I guess basically each year we would go back to the Industrial Customers and Newfoundland

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MR. HAYNES:
Power to get a revision of their load forecast. I think most of the short-term ones are questioned in a sense that is anything there that we have some discomfort with or don't quite understand their rationale for it, we'll go back and seek explanation. For instance, if the Mill has a shutdown, presumably they would put that in the forecast and we would reflect that in our forecast and so on and the same thing with Newfoundland Light and Power. We would get a forecast and we would look at the energy and demand numbers and question if we felt that it was something out of the ordinary which we didn't quite understand, we would seek resolution to understand that. But by and large, they are accepted largely as proposed with some minor tweaks here and there.

Q. And what sort of thing would impel you to question a load forecast in those situations?

A. If there was a change in the load factor based on the historic one that they had or if there was a significant reduction in the energy requirements, particularly from an Industrial

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Customer, whether it would be a paper mill or NARL. And often times if they have a planned shut down or a major overhaul of any component, we would see that and we would just seek to verify what the rationale was and to ensure it was done. If Newfoundland Power had a significant change in their load factor, from year to year, we would question to, maybe a double check on their part or a double check on our part to ensure it is the best guess at the time.

Q. Okay. And did you question the load forecast that was produced in the fall of 2001 by Newfoundland Power for its requirements for the test year of 2002 at the last hearing?

A. That was reviewed by our forecasting group and there was nothing that--the explanations provided were all rational, logical and we accepted that particular forecast.

Q. Can you tell us what those explanations were?

A. I can't tell you that offhand, I'm sorry. That would have been done between our forecasting group and the appropriate department in Newfoundland Power. I don't know the detail.

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Q. Again, if I can get you to look at page 31 of your evidence and at the bottom of the page there in Section 8.2 at lines 28 and following, you note that for 2002, your overall sales and bulk deliveries were 48 gigawatt hours higher than the operating forecast.

A. Yes.

Q. That's a correct number, is it? And that resulted from two factors which you refer to in your next sentence, "utility sales being 107 gigawatts hour higher than forecast and sales to Industrial Customers being 59 gigawatt hours lower than expected", is that correct?

A. Yes.

Q. Okay. If we could, Mr. O'Reilly, put up IC-1C, page 3 of 98. I recognize, Mr. Haynes, that this is the dreaded Cost of Service and I perhaps should ask you initially, you know the extent of your involvement in connection with the Cost of Service Study itself.

A. Very limited.

Q. You recognize that you have significant inputs into it.

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A. In meeting our customer demands, yes.

Q. Yes, okay. This is the 2002 actual Cost of Service for the total system. And it shows, among other things, the revenue to cost coverage in the last column on the right hand side. Do you know the significance of revenue to cost coverage as it shows up here?

A. I don't have a detailed knowledge of explaining the Cost of Service model when that's done. And I would prefer to push that to Mr. Banfield and Mr. Greneman.

Q. Um-hm. I understand that. Do you know what ratio of revenue to cost is targeted for the Island Industrial Customers in the Cost of Service?

A. I'm not sure offhand.

(1:15 p.m.)

Q. I just have to see if we can look at this another way, Mr. Henderson (sic.). Do you recall what the differences were between the initial load forecast that Newfoundland Power produced in 2001 for the 2002 test year and the final one which was incorporated into the Cost of Service during the course of the hearing?

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MR. HAYNES:
A. I think the 2002 test year would be included in some of the schedules of the forecast. The 2002 forecast for Newfoundland Power is in schedule 11 and the forecast was 4485.1 gigawatt hours and the actual was 4588.7.
Q. That's from your schedule 11?
A. That's in schedule 11, yes.
Q. Now, my question was as to how the forecast which Newfoundland Power provided to you initially in 2001 changed between the initial forecast and the final forecast that was incorporated into the Cost of Service.
A. I don't have that knowledge offhand as to what was actually the initial versus what was in the final test year.
Q. You had some discussions with Mr. Kelly this morning about the significance of the load factors that are used and that's related in part to his discussion about the generation credit. Do you know what impacts the load factor assigned to Newfoundland Power has under the Cost of Service Study?
A. It certainly has an impact. I think in the order of less than 50 percent load factor,

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49.2, 49.5 and it will affect the actual megawatt number to some degree, but I can't speak to any specifics on that, but I would suggest that I believe Newfoundland Power will be appearing as a witness and if you were looking for an explanation of their load forecasting methodology and those numbers, it may be better directed to Newfoundland Power.
Q. Okay. Can I refer you to page 41 of the testimony of Mr. Olser and Mr. Bowman. Looking at lines 12 through 18 where they remark upon the updating of the Cost of Service originally filed to reflect the new Newfoundland Power load forecast. I mean, I take it you were aware that there was such an amended forecast filed, is that correct?
A. Yes, I do recall that, but I did not delve into that in any specific degree. And I guess to explain that, I think it still would be most appropriate that as Newfoundland Power are appearing, that they may be better to explain that change than us.
Q. Okay. But I mean, it was Hydro that incorporated this change into the Cost of Service for 2002, correct?

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A. Oh yes, and we did incorporate their forecast. We did discuss this with Newfoundland Power and we accepted their explanation and rationale as to the merits of that particular load forecast.
Q. Okay. And do I take it that you agree with the substance of this evidence that the initial forecast peak was 953,251 kilowatts at transmission and the revision reduced that to 923,476 kilowatts?
A. I presume he's taken the information from the evidence, so I have no reason to suggest otherwise.
Q. Um-hm. And Hydro took that nine hundred and twenty three thousand kilowatt number and incorporated that into the Cost of Service, correct?
A. Well, I guess the forecast was 1001 according to schedule 10, but that may be losses, distribution losses or whatever incorporated in there, I don't know.
Q. Okay. And I take it, we can probably confirm and I guess this takes into account the transmission losses--but this number is taken from the Cost of Service Study as it appears

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in line 17 of the page that we're looking at here, that the actual recorded peak was 1,047,534 kilowatts.
A. I assume, I didn't go back and check the report. I would suggest, I mean, it is a forecast, there are a lot of variables that affect the actual end number at the end of the year, the degrees days, et cetera, et cetera. So, at that particular time, I assumed it was Newfoundland Power's and best guess and we concurred with their forecast, it changes.
Q. My question, I guess, is to you whether this forecast reduction of 30,000 kilowatts without any significant reduction in energy forecast would be sufficient to cause Hydro to question Newfoundland Power's forecast?
A. As I indicated, we do question Newfoundland Power's forecast when we see changes that would draw our attention. They're explained and rationalized and it was accepted. And -
Q. You can't tell us at this point what that explanation was, can you?
A. I don't know offhand, but as I said, with respect to Newfoundland Power, they do have a witness appearing and they would be in the

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MR. HAYNES:
best position to explain their forecasting methodology and any changes based on the actual experience they incurred.
Q. I'd like you to undertake, sir, to provide us with the explanation that Newfoundland Power gave you at the time. Would you do that? (Undertaking)
A. Okay, yes.
GREENE, Q.C.:
Q. I would point out this is also the subject matter of cross-examination in the last hearing by the Industrial Customers that was also considered by the Board and the Board approved the use of this forecast and the Cost of Service methodology and we will undertake to provide the explanation as we did during the last hearing.
HUTCHINGS, Q.C.:
Q. Well, we now have the additional information of how many millions of dollars this here actually cost us, Mr. Chair, so I think it's certainly worthwhile to pursue this a little further and I would like that information in order to be able to proceed.

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GREENE, Q.C:
Q. And again, as Mr. Haynes has pointed out, Mr. Henderson, from Newfoundland Power who is the witness who actually has responsibility for forecasting at Newfoundland Power will also be a witness at this hearing and it may be appropriate that if the Industrial wish to pursue that issue, that it would be done to the person or to Newfoundland Power whose forecast we're talking about.
HUTCHINGS, Q.C.:
Q. We'll certainly be pursuing with Newfoundland Power as well, Mr. Chair, but I mean, given that this is Newfoundland Hydro's hearing and they are the ones who have a judgment to exercise as to whether or not they accept the information that Newfoundland Power provides to them, I think it's still appropriate to pursue it as we have, but we will be pursuing it with other witnesses as well.
GREENE, Q.C.:
Q. The only point is we're talking about a forecast that was approved by the Board and used in setting the 2001 rates. We're looking at the past. We will provide the explanation

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as requested. I just question the merit of pursuing it as we're looking at setting 2004 rates.
HUTCHINGS, Q.C.:
Q. A couple of other points that we may be able to fit in before the break, Mr. Haynes, on the subject of hydrology, in the previous Board order P.U. No. 7, and perhaps we could go to that at page 48, down a little further toward the bottom of the page there. We have the direction of the Board there in bold at the bottom in terms of the use of the 30-year average annual hydraulic production of 4, 425 gigawatt hours, that's the basis for the test year hydraulic forecast. If we were to go back one page, I think we'll see there that just under the heading "test year, hydraulic production forecast", the long-term forecast that Hydro is using or wished initially to use in the 2002 test year was 4,285 gigawatt hours, is that correct?
A. Yes.
Q. That's what you wanted to use in 2002, is that correct, Mr. Haynes?
A. That's what was used in that hearing, yes.

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Q. Yes, okay. If we can move now to Table 7 of your current evidence, table 7 on page 30. This table shows the recommended full historic records and the column headed existing 1973 to 2002, that's the 30-year record, is that correct?
A. That would have been the most recent 30-year record at that time. In the last rate hearing, obviously, we're using numbers up to the end of 2001. This would reflect numbers for our full record that we have going back 30 years. So, it would not be identical, but it's based on the same premise, it's a 30-average. So, it dropped an old year and added a new year.
Q. Okay. And as we discussed earlier, while the inflows themselves are not affected by Granite Canal, the hydraulic capability certainly is affected and adds 224 gigawatt hours to both columns, correct?
A. That's correct, yes.
Q. Yes. So, can you just explain for us how the full recommended historic record as it stands now, if you take out Granite Canal, the 224 gigawatt hours has changed since the 2002 test

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HUTCHINGS, Q.C.:
year numbers. As I calculated, there would be a 51 gigawatt hour difference?
A. Fifty one being, I'm sorry, the -
Q. Okay. If you took the full recommended historic record from your table and deducted the 224 from Granite Canal, you should end up with 4,234 gigawatt hours.
A. Yes.
Q. And that is 51 gigawatt hours less than the 4,285 that you wanted to use in 2002.
A. That would be the addition of a 2002 experience, which we did not have obviously, during the 2002 hearings. So, it was a low inflow year, I believe it was the seventh or eighth lowest on record or something to that effect. So, they would actually reduce the average. So, basically the table there reflects the 2002 experience which was a low inflow year.
(1:30 p.m.)
Q. Yes. And it affects the average on the 30 year one, even more so, obviously as would be mathematically correct. I think there's a 67 gigawatt hour difference between what the

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Board ordered in P.U. 7 on the basis of the 30 year average and what that would be today once you take out Granite Canal, is that correct?
A. The Board Order was the most recent 30 years experience and that's what we prepared for this particular filing.
Q. Do you know what amount of money is reflected in the revenue requirement as a result of that change of how much, for instance, would be represented by those 67 gigawatt hours, in terms of revenue requirement?
A. Well, it would be--the simple approach would be, and I don't want to calculate the numbers, would be that particular amount of energy at 624 kilowatt hours per barrel, times $29.20 a barrel, based on the filing.
Q. Okay. That's probably as good a time as any to break, Mr. Chair.
GREENE, Q.C.:
Q. Excuse me, Mr. Chair. If I might, I had a document I'd like to circulate before we concluded today.
CHAIRMAN:
Q. Sure.
GREENE, Q.C.:

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Q. You will recall that we dealt earlier with the undertakings that had been given prior to today and I had indicated with respect to one that was given to Mr. Kennedy about providing historical information for the key performance indicators, that we would be able to do that. And what I would like to distribute now is the actual information with respect to the key performance indicators with the historical data back to 2000 and with the forecast for 2003 where appropriate, including actuals and where we didn't use actuals, we never used the target for 2003. So, this is our last undertaking to respond to prior to those that are required for today. So, I have copies to distribute now.
CHAIRMAN:
Q. Thank you, Ms. Greene. Thank you, Mr. Hutchings and Mr. Haynes as well. According to the calender, I guess, we have a day off tomorrow. No bad strategic scheduling after an election day, I don't think.
GREENE, Q.C.:
Q. I wonder if it would be possible if the Industrials could indicate how long, further

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they may be so we can get some idea of the schedule for Thursday and Friday.
CHAIRMAN:
Q. We can do that.
HUTCHINGS, Q.C.:
Q. I would anticipate, Mr. Chair, that if we are not finished by the break tomorrow, we'll be finished shortly thereafter.
CHAIRMAN:
Q. Okay.
MR. KENNEDY:
Q. You're putting me on the spot, I would--I shouldn't be any more than half an hour or 45 minutes with Mr. Haynes. So, it's a reasonable prospect you might finish with Mr. Haynes on Thursday.
GREENE, Q.C.:
Q. Yes, I thought that might be the case and I just wanted to indicate, we are prepared to proceed with Mr. Martin on Friday and I just wanted to ensure that that was everyone's understanding.
CHAIRMAN:
Q. I'd like to do that if we can, yes. Sounds good to me. Do this need to be assigned a -

MS. NEWMAN:

Q. It would already have, I guess, a number assigned. We can track that down and let everybody know what the number is.

CHAIRMAN:

Q. Okay. Thanks very much, enjoy your evening and we'll see you at 9:00 on Thursday morning. Thank you.

Upon conclusion .

CERTIFICATE

I, Judy Moss Lauzon, hereby certify that the foregoing is a true and correct transcript in the matter of Newfoundland and Labrador Hydro's 2003 General Rate Application for approval of, among other things, its rate commencing January, 2004, heard on the 21st day of October, A.D., 2003 before the Board of Commissioners of Public Utilities, 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 21st day of October, A.D., 2003

Judy Moss Lauzon