MR. NOSEWORTHY, CHAIRMAN: Thank you and good morning. I trust everybody had a good weekend. Before we get started, counsel, are there any preliminary matters?

MR. KENNEDY: I don't believe so, Chair.

MS. BUTLER, Q.C.: I wonder, Mr. Chairman, if we might just introduce Mr. Larry Brockman, who is Newfoundland Power's witness on the cost of service matters.

MR. NOSEWORTHY, CHAIRMAN: Good morning, Mr. Brockman. How are you? We've used your name a couple of times in vain last week. *(laughter)* Good morning and welcome, sir.

MR. BROCKMAN: Good morning.

MR. NOSEWORTHY, CHAIRMAN: Good morning, Mr. Osler.

MR. OSLER: Good morning, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Good morning, Mr. Browne. I wonder could I ask you to begin when you're ready, please?

MR. BROWNE, Q.C.: Thank you, Chairperson. Good morning, Mr. Osler.

MR. OSLER: Good morning, Mr. Browne.

MR. BROWNE, Q.C.: Mr. Osler, can you go to **your evidence of September 12th, 2001, on page 12, which is the first supplementary** ... there you deal with issues of rate design on page 12 and use of an energy-only rate for NP. Can you just read that into the record, please?

MR. OSLER: Line 13?

MR. BROWNE, Q.C.: Yes, line 13.

MR. OSLER: "Use of an energy-only rate for NP. Hydro has proposed an energy-only rate for NP that is inconsistent with normal rate design principles and fails to track the costs NP imposes on the hydro system. In addition, this rate fails to reflect the practice regarding wholesale rates on similar systems in Canada."

MR. BROWNE, Q.C.: Now, what other similar systems in Canada are you referring to there?

MR. OSLER: I had two in mind, first being the Ontario system, which is, you would know, I guess, has a fair amount of capital intensive generation either in the form of nuclear or hydro, as well as some thermal. With Ontario Hydro, and I'm thinking back to the days when it was a regulated system, Ontario Hydro providing the bulk of the power for all of the residents but there were many, many municipal utilities as well as a number of what they call larger users, that's five megawatts or more, served directly by Ontario Hydro, and the practice that evolved in it there was one of a two-part rate structure for all of these, what they call large users, either municipal distributors or large users industrial. On a much smaller level, I'm advised that in the Northwest Territories, Power Corp, it too has used a two-part rate in dealing with its distributor in a hydro-based system.

MR. BROWNE, Q.C.: When you ...

MR. OSLER: Sorry.

MR. BROWNE, Q.C.: Okay. No, continue. You need to complete your answer.

MR. OSLER: One more example was that in Yukon when the Northern Canada Power Commission had been supplying power to the local distributor, introduced a two-part rate. That got melded into a one-part rate similar to the one you've got here at the time period when the distributor effectively was managing the Crown company through a contract and they ended up putting it into a one-part rate. Now that contract is over, I don't know what would be the situation there as they go into the next rate hearing, whenever that may be.

MR. BROWNE, Q.C.: Now when you say in the first sentence, there, "NP ... Hydro has proposed an energy-only rate for NP that is inconsistent with normal rate design principles," what do you mean by that?

MR. OSLER: Well, in normal ... removed from the classification and allocation of costs step inter rate design. When dealing with customers who are purchasing power at a scale that makes clear the, clearly justifies in terms of economics the meterings for more sophisticated, keeping track of their loads, metering of demand, etc. It's been my experience that one would try to track both capacity costs and energy costs in the rate structure as well as having gone through the effort of putting them together when doing the classification of allocation of costs and assigning costs to different customer groups, and the reasoning for that approach to rate design would be that you want to give people price signals on the one hand for efficiency reasons that relate to both capacity and energy use, and secondly it would have some advantages in lines of rate design people historically in stabilizing revenue to a certain degree by locking in certain demand charges through ratchets and other things so the utility could rely on a certain amount of relatively stable income relating to its fixed costs and its capacity costs, and how you design the energy tariff becomes an interesting challenge, but you can design it various ways. You don't have to have only one energy rate when you're doing the energy portion of it. You could have stepped rates or increasing blocks or decreasing blocks depending on what you're dealing with, so that when we look at even Newfoundland Power, they do (inaudible) what I'm saying when they start treating their own customers. They treat those who can afford meters with a two-part rate, whereas the residential customers who traditionally don't consume enough power to justify that type of metering, they have a single rate.

MR. BROWNE, Q.C.: So there could be advantages and options for customers with a demand component in the rates.

MR. OSLER: The rate design approach would look at it, I guess, from the point of view of both customers and the utility, and the advantages that would be there would be either from the perspective of tracking costs as they've been discussed and assessed in the cost of service, separately for capacity and energy, and you would try and design it in such a way you could also achieve some price signals and perhaps some incentives towards better efficiency in use by both the utility and the customer.

MR. BROWNE, Q.C.: On **page 26 of your evidence, the same supplement, line 27**, you make reference to Newfoundland Power's energy-only rate as well. Just can you read that into the record, please?

MR. OSLER: "Newfoundland Power is currently subject to a rate that includes only an energy component with no demand charges or fixed monthly charges. This energy component far exceeds the cost of service study conclusions regarding the embedded energy cost assigned to NP as it encompasses the demand costs and customer costs assigned to NP as well."

MR. BROWNE, Q.C.: What do you mean by that, it far exceeds the cost of service study conclusions?

MR. OSLER: What I mean is that the amount in the rate includes not only what we call energy in the cost of service study but also what is called capacity in the cost of service study, so the actual energy rate far exceeds the costs that are classified as energy and assigned to NP in the cost of service study as energy.

MR. BROWNE, Q.C.: And on the next page, on page 27, on line one, can you read that into the record, sir?

MR. OSLER: Hydro has proposed no change to the energy-only rate structure for NP. In addition, Hydro has filed a letter they have received from NP in **PUB-68** which states, "NP's interpretation that a demand charge and fixed charge component of the wholesale rate would increase revenue volatility to the detriment of customers."

MR. BROWNE, Q.C.: Do you agree with that?

MR. OSLER: I do not think that a two-part rate needs to necessarily increase revenue volatility to the detriment of customers. I can see why utilities may be concerned with it but I do not think it necessarily flows.

MR. BROWNE, Q.C.: And your last sentence, line seven there?

MR. OSLER: "Our view of the matter does not support the conclusion that an energy-only rate is the suitable rate design for NP."

MR. BROWNE, Q.C.: Now, Newfoundland Hydro and Newfoundland Power in this hearing are advocating an energy-only rate. Has that always been the position of Newfoundland Power to ...

MR. OSLER: I'm not intimately familiar with the history but I understand that hasn't always been the position of Newfoundland Power from what I've heard in testimony in the last week.

MR. BROWNE, Q.C.: Can you go to **page 29 of your evidence**, sir, and beginning with line six, "In contrast," can you read that into the record?

MR. OSLER: "In contrast, NP's expert, Brockman, page 28, notes that at this time he is not recommending a demand energy rate for Newfoundland Power despite the fact that he has recommended one at times in the past."

MR. BROWNE, Q.C.: Okay. How do you know that? How did you come to that conclusion?

MR. OSLER: I believe he said so in his testimony. I think he acknowledged that he had recommended in the past and although he had done that he wasn't recommending it in this instance. I hadn't reviewed his past testimony.

MR. BROWNE, Q.C.: And just continuing with line eight.

MR. OSLER: "The reasoning given is that it would tend to increase the volatility in revenues for both Hydro and NP, however, he provides no substantiation as to how such a rate would increase volatility."

MR. BROWNE, Q.C.: Do you share that conclusion, that a demand rate would increase volatility in revenues for both Hydro and NP?

MR. OSLER: It doesn't have to necessarily. If there were very specific concerns, they would identify as to what happens on the margin when you're charging for the energy that one could address it in a two-part energy rate, but essentially a demand charge with some ratchet provisions, which I assume would exist, would introduce stability to Hydro's, Newfoundland Hydro's income stream because regardless of the load, whether, if it declined, they would get locked in this amount of income, and it would introduce similarly, perhaps to the adversity of Newfoundland Power, but it would introduce stability into how much it was being charged if its load went down. In the case of the energy rate, the issue for Newfoundland Power has to relate to how the energy rate compares to the (inaudible) run-out rates that it's using for its customers and I assume it would probably have a need for the two utilities to think through how the rate designed worked as an integrated package.

MR. BROWNE, Q.C.: Now, if Newfoundland Power advocated a demand component in the past, using that reasoning, reasoning that they give now for not introducing it, wouldn't it have increased volatility in their revenues at that time?

MR. OSLER: I'm not ...

MR. BROWNE, Q.C.: Wouldn't the same rationale apply?

MR. OSLER: I'm not aware of anything that has changed in the nature of the system in the time period since I gather this other testimony was offered that would explain a change in position. I think though I have heard people say that this position is intimately tied into their interpretation of the RSP and that absent the RSP I think Mr. Brickhill at least suggested that the situation could be quite different. Anyway, the RSP has been in effect since the mid '80s from the point of view of Newfoundland Power and Hydro, so again I don't see how it has changed anything that would lead to a change in position on this matter.

(9:45 a.m.)

MR. BROWNE, Q.C.: And other companies with which you're familiar, they must have a demand component, do they not?

MR. OSLER: Well, the ones I listed earlier, certainly had demand components.

MR. BROWNE, Q.C.: And they survive, do they not? They end up with revenues and they are not subject to a volatility which is going to bring them under or anything, are they?

MR. OSLER: No.

MR. BROWNE, Q.C.: Just moving to another topic, last week there was some discussion about the 1-CP, 2-CP and 4-CP, and on **page 10, lines 24 through 25 of your September 12th, 2001, testimony** ...

MR. OSLER: Which lines were you on?

MR. BROWNE, Q.C.: Lines 24 and 25. You say, "Both Bowman, pages 7 and 8, and Brockman, page 23, disagree with Hydro in this regard, however, there is no basis to increase the allocation to 4-CP and there is likely benefit to retaining the current 1-CP for consistency with allocation transmissions and consistencies with similar utilities." So it is your evidence then that if the Board in its, decides against moving to the 4-CP that you will be content with the 1-CP?

MR. OSLER: Correct.

MR. BROWNE, Q.C.: And the 4-CP, would 4-CP cost the industrials money?

MR. OSLER: I have to check the percentages. It might be that 4-CP has a slightly more adverse classification, sorry, allocation to industrials than 1-CP but ...

MR. BROWNE, Q.C.: So it could be more expensive for the industrials.

MR. OSLER: It could be, but that wasn't central to my thinking. My thinking was based on what the experience is with other utilities of this type in Canada, and I'm not aware of any of them using the 4-CP.

MR. BROWNE, Q.C.: **On page 10, lines 27 to 28, of your September 12th, 2001, supplementary evidence**, you state, "Hydro's application does not consistently address the various interruptible demand alternatives that Hydro maintains. The treatment is critical for calculation of the system load factor for classification of hydraulic plant and cost for allocation of the generation and transmission demand costs on the coincident peak of generation and for rate design of interruptible demand programs." Then you say, "In calculating the CP for allocation and for determining the system load factor for COS purposes, Hydro reduces NP's peak to reflect interruptible demand." And then you say, "This treatment appears to be inconsistent with the industrial customers' interruptible demand and in any event serves to calculate a revised load factor for its cost of service purposes that is different than Hydro's load factor for planning purposes." Can you tell us exactly what that means?

MR. OSLER: This whole topic is dealt with in **Section 3.5 of this evidence and starting, I guess, at page 17**. I'll try and just summarize it. I think the Board has heard by now considerable evidence on how the interruptible contract with one of the industrials, called Interruptible B, allows the Utility to interrupt that customer for, I think, up to 46 megawatts during the peak periods of the year and that this is a cheap way of getting extra capacity security on the integrated island system. I think the Board has also heard evidence that there is a similar capability Hydro has with its wholesale customer, Newfoundland Power, and it's called a generation credit, but essentially it allows Hydro to control the dispatch such that if it had a shortage during the year at a certain point in time it could call upon NP's generation, and return for each of these provisions, which I think many people have now described as being basically similar, at least there's answers to questions that say they are similar and there's evidence on the record that says they're similar in terms of what they do for the Utility, Hydro. In the one case, the Interruptible B case, the customer by a contract receives $1.33 million a year as payment for making this interruptible capability available. That comes down to about $28.20 a kilowatt per year. That cost is treated in the cost of service study as a production demand cost and it is assigned, therefore classified to demand and allocated according to the ground rules that you've been talking about among all the different customer classes, so that the industrial class pays a share of that cost. It is transparent, it is cost justified, it is fully treated in the cost of service. The only thing that's a bit odd about it is it's done by contract rather than by a rate approved by the Board, and there's an issue there as to whether or not that should become part of the rate structure offered to anybody who's prepared to take it up rather than done on a contract basis.

MR. BROWNE, Q.C.: **On page 18 at lines 11 to 20** you indicate there, "There are inconsistencies in the treatment of Newfoundland Power generation on the industrial customer Interruptible B power."

MR. OSLER: Right, because if I look at the Newfoundland Power generation credit, it is not dealt with as a cost payment to Newfoundland Power. It is done as a credit in the cost of service study. It is very difficult to find it, so it's not done in great transparency. It's there and we found what it's worth through interrogatories and questioning but it's not something you could find by picking up the cost of service or anything else in terms of its value. It has effects on the cost of service study given the way it's dealt with by reducing certain loads and things like that and that are difficult to understand and not necessarily clearly justified, and of course it's very difficult to understand the extent to which the one form of interruptible dispatchable control that the Utility has with Newfoundland Power is being fairly and consistently costed and paid for compared with the Interruptible B type of dispatchable control that they have with Abitibi, and that's in essence the issue at the stage that it was presented in the September evidence as a concern about consistency and transparency and trying to get to the bottom of it. I think since then we have learned a little bit more and can know a bit more now of the costs relating to the credit, we didn't have before, and I gave some comment on that in my opening direct testimony.

MR. BROWNE, Q.C.: Do you believe that an explicit interruptible rate option made available by Hydro to Power, similar to that offer by Hydro to industrial customers, was appropriate?

MR. OSLER: Well, I wouldn't even call it a rate structure the way it's done. It's sort of ... it's a credit in ... done, I gather, with the approval of the Board historically, so it's not underhanded or anything but it's in the cost of service study rather than a rate in the normal sense of the word. I would think it would be preferable to have a transparent rate structure that clearly treats all parties the same way, indeed makes it open in a DSM context for other parties that might want to think about making interruptible load available.

MR. BROWNE, Q.C.: So you would say that it should be available.

MR. OSLER: I think it should be available, should be available on a rate form rather than by deals and it should be available to anybody who can provide it subject to the terms and conditions, and I cite as an example of that, in the 1990s, in Manitoba Hydro's case, with a fair amount of persistence from some of its customers, they eventually got around to offering curtailable rates as a rate form for their larger industrial users, and historically had said this is not possible to do on a hydro system and wouldn't be worth it, but they do have at least one customer still on that and very important to them and they had another one on it for a while, so it didn't ... not everybody jumped to use it but some people used it to their benefit and to the benefit of all the other customers in the system.

MR. BROWNE, Q.C.: Do you feel that there should be a contract specifically identifying the generation services to be offered by, be it between Hydro and Power along with compensation similar to contracts between Hydro and the industrial customers? Do you believe things should be collapsed to a contractual basis between Hydro and Power?

MR. OSLER: I think they should be dealt with on a similar basis. I'm not sure whether the contract role (phonetic) range is necessary when you have rates approved by a board. I think that's an interesting question all by itself. If there was a rate approved by the Board, then it's transparent, it's open and everybody can see it. Many utilities seem to still feel that we need to have a contract as well, and if that's felt to be the case then we should have a contract with each of them.

MR. BROWNE, Q.C.: So are contracts prevalent in the industry from your understanding?

MR. OSLER: They vary. They are, I guess, prevalent more than I would perhaps like at times but they are ... utilities' law departments seem to feel they like to have a contract.

MR. BROWNE, Q.C.: Will be more of a business-to-business relationship, I guess, would it?

MR. OSLER: Right, but it's always subject to the board's orders so, you know, what I find personally is that sometimes you have difficulty making darn sure that the contract is consistent with the order because usually people that write it, in the big utilities, they're not necessarily involved in the rate case, so they sit down and start all over again. Anyway, that's a side comment.

MR. BROWNE, Q.C.: The earlier part of this hearing we dealt with duplications and services between Hydro and Power, and I think there was some discussion concerning a VHF radio system which Hydro was proposing to purchase at $8.5 million, and there was some suggestion, I think, that themselves and Power at one point could have worked out some agreement when Hydro was about to purchase a new system, which hasn't happened. But from the industrial perspective, do you see savings for the industrials if duplications in services between the utilities were dealt with?

MR. OSLER: I think there's potential proceedings for all the customers to the extent that the system can avoid duplication and increase its overall efficiency between the two utilities.

MR. BROWNE, Q.C.: Do you see any merit in this province in having one vertically-integrated utility?

MR. OSLER: I haven't considered it. It would seem, from experience I've seen in a few other places, it would require, I would think, careful consideration of all the issues before I'd want to get any comment on it.

(10:00 a.m.)

MR. BROWNE, Q.C.: **On page 11, lines 10 to 13, of your September 12th, 2001, testimony** ...

MR. OSLER: Sorry, page?

MR. BROWNE, Q.C.: Page 11, lines 10 to 13.

MR. OSLER: Thank you.

MR. BROWNE, Q.C.: We're discussing frequency converters there. You indicate, "There's no principle or reasonable basis justifying a change in assignment of cost related to frequency converters from common to industrial customer specific," and you can recall there was previous discussions during these hearings on this particular issue. If the converters which were judged to be useful to two or more classes previously are now judged to be useful for only one customer class, would that justify changing the assignment of costs from common to specific?

MR. OSLER: I think in this case, no, because the benefit related to the overall system is embedded in the system in its origins and very hard to take away fairly at a later time and say it doesn't matter anymore, whereas the cost of changing the rules would be very significant, it would appear, for the one customer that is likely to be affected by it.

MR. BROWNE, Q.C.: So if they only service one particular customer, how could they be described as common?

MR. OSLER: Common in their origin in the sense that the decision was made by all parties to develop the system a certain way which left these customers, and this one in particular, continuing to rely upon a system that would provide them through the utility as a common cost feature for their frequency conversions. If the system had developed a different way, perhaps along the lines of the frequency that this customer has, that issue would be moot. The benefits of that decision continue to flow for all of Newfoundland. The costs of making the change today rather than umpteen years ago would be borne only by the one customer. I think that creates issues that don't make me comfortable with saying it's easy to no longer call it common.

MR. BROWNE, Q.C.: Well, effectively, I guess, they could be taken out of service, couldn't they, if the industrial wasn't there to use them, is that not correct?

MR. OSLER: If there was no user they could be removed from service, correct.

MR. BROWNE, Q.C.: So the only one that they are serving is the industrial.

MR. OSLER: (inaudible) two industrials, likely only one in the future, yes.

MR. BROWNE, Q.C.: On **page 12, lines 18 to 25, of your September 12th, 2001, testimony**, we're talking about the wheeling rate and transmission costs there, and you note that, "All transmission costs are included in Hydro's calculation of the wheeling rate." Does this not result in an average cost of transmission or what is commonly referred to in the industry as a postage stamp rate? Are you familiar with that term, postage stamp rate?

MR. OSLER: I'm familiar with the term, yes.

MR. BROWNE, Q.C.: Okay. Can you tell the Board what that means?

MR. OSLER: Generally applied to customers over, say, a whole country or a whole jurisdiction, that they all can have the same rate for use of a service without it being differentiated on the basis of distance or location so that a rural customer would pay the same as city customers, and in our province, people up north would pay the same as the people down south, etc., that type of thing.

MR. BROWNE, Q.C.: It's the same as the postage stamp, right, we all pay whatever it is now, 47 or 48 cents?

MR. OSLER: Right.

MR. BROWNE, Q.C.: No matter where you live in the ...

MR. OSLER: No matter where you live you pay the same amount to send a letter in Canada, a different amount if you're going to send it somewhere else.

MR. BROWNE, Q.C.: Saving Labrador, I think. Some people have an argument up there on occasion. Is postage stamp pricing not a common method of transmission pricing used in the industry?

MR. OSLER: I'm not intimately familiar with transmission tariffs but my understanding of the recent evolution of some of the tariffs as required for utilities such as Manitoba Hydro to meet American requirements is that they have to develop a cost justified, I've never heard them use the term in this context, but postage tariff for your jurisdiction so that anybody who's a wholesaler can have access to flow through the jurisdiction, etc. If Manitoba Hydro wants to have access to American markets, they have to turn around and provide a tariff that does the same for the Americans, however, there have been tariffs, I believe, that have been done on different bases than just postage stamp, and I don't know whether, I don't know enough to know whether the (inaudible) rules in the States allow variations as long as they're cost justified.

MR. BROWNE, Q.C.: In this province, provided all the wheeling transactions in the province, say subject to this charge, is this not an acceptable rate and procedure for wheeling?

MR. OSLER: It could be if that was the overall intent, to develop a tariff across the whole jurisdiction for wheeling from any point to the other one.

MR. BROWNE, Q.C.: **On page 21, lines 14 to 19, of your September 12th, 2001, testimony**, you state that, "It is not clear why the $3 million on the secondary sales revenue in Labrador would be allocated to the Labrador consumers with already low rates rather than being allocated to offset the rural deficit." On what basis should the $3 million be allocated to offset the rural deficit? What's your rationale?

MR. OSLER: I think this is addressed very briefly in a response to Newfoundland Hydro No. 96, but the point is that we are dealing with something that is a surplus and is therefore not cost justified, and that's a surplus that arises without any debate about it not going back to the customer, so you start from the premise that there isn't a cost-justified basis for assigning this surplus any more than there's a cost-justified basis for assigning the rural deficit, and because there is no principled cost causation basis to distribute the revenue credit and there's no cost causation basis to distribute the rural deficit, it would seem that you then have some discretion, and it struck me, and I think others, a few others mentioned this, that it may be something that you would apply this to the rural deficit rather than apply it only to the customers in that particular system.

MR. BROWNE, Q.C.: Why, just because it's a surplus and it's $3 million worth of money so the Board can just take it and order it to be applied against the deficit? What is the rationale here?

MR. OSLER: There's no rationale for deciding that it should be assigned specifically to that system or the customers in that system. The rural deficit is assigned to customers in different systems, as I think the evidence has gone through. If there's a problem with the rural deficit in the sense that it is not being paid for by the customers that are getting the service from it, and you got a surplus that has been derived in another situation over and above the cost required to serve that customer, it seems that an option is there to apply the surplus to the deficit. I'm not advocating it and I'm not disputing it. I'm just saying it seems to be an option that would be before the Board for parties to argue and consider seriously.

MR. BROWNE, Q.C.: That's a form of secondary revenue, wouldn't you agree?

MR. OSLER: Definitely.

MR. BROWNE, Q.C.: And is it your position that all secondary revenues which may appear be allocated to the rural deficit?

MR. OSLER: No.

MR. BROWNE, Q.C.: Just this particular one.

MR. OSLER: This is a pretty big one and the other secondary revenues are fairly small and very much relate to use of a specific system and their benefits are assigned back to the users of that system.

MR. BROWNE, Q.C.: **On page 22, lines 10 to 11 of your September 12th, 2001, testimony**, you're referring to various adjustments there, and in addition you say, "We do not see the basis for proposing to delay past 2002 the other adjustments that Hydro considers appropriate in the long-term." Can you expand upon that, please?

MR. OSLER: We're talking in this context around again the rural deficit and the rural rates and the issue of phasing in on higher charges or new ways of dealing with them, and it struck me that the application in many respects in this regard said we're going to do something but we'll tell you what it is next time, and given the history of what happened the last time we had a, you had a rate hearing here in detail and how long it took to come to grips with some of the things that came from it, one would have thought that it would be nice to have tabled in this hearing an actual five-year plan starting now or a seven-year plan or whatever, and start implementing it now. That's what I'm getting at.

MR. BROWNE, Q.C.: So that's what you're recommending the Board to do.

MR. OSLER: I'm not sure the Board has the ability to deal with it absent the evidence as to, from the applicant, and I guess the Board could order the applicant to provide a game plan and then let's review it.

MR. BROWNE, Q.C.: I want to ask you some questions concerning your position on the RSP. Is it fair to say that since the RSP was set at $12.50 in the early 1990s, customers have been receiving incorrect price signals?

MR. OSLER: Yes.

MR. BROWNE, Q.C.: And is this because Hydro has been undercollecting revenues through the RSP balancing account rather than passing them through to consumers in the year in which they occur? Is that the nature of the incorrect price signals?

MR. OSLER: It's been sending them a price signal each year in their rates that doesn't reflect the full cost of the oil and the result is that it undercollects through rates and assigns the deficit, so-called, to the RSP, so therefore gives the wrong price signals.

MR. BROWNE, Q.C.: Now, are industrial customers concerned that they're facing a ... there's a $26 million deficit in the RSP account in 2002 and 2003, according to **your table on page 35**. Can you go to that table, please?

MR. OSLER: Sorry, which number did you look at?

MR. BROWNE, Q.C.: The table on page ...

MR. OSLER: 35, yeah.

MR. BROWNE, Q.C.: ... 35.

MR. OSLER: Right.

MR. BROWNE, Q.C.: Okay. We're referring to the deficit that you see the RSP account from an industrial perspective in 2002, 2003, and I think you base oil at 25 and 20 and 15. You don't base it at $28, I notice.

MR. OSLER: No. I was just looking for some symmetry of trying to understand the implications of $5 up and down.

MR. BROWNE, Q.C.: And just before we get to the table, is it your position that it should be based at what is forecast, $28 a barrel? Is that the position of the industrial customer?

MR. OSLER: I think we should keep clear that whatever I'm testifying to is my position and I don't ...

MR. BROWNE, Q.C.: Yes, but you're brought in by them and I think you're brought in to give opinion, so can you give us your opinion?

MR. OSLER: I'll give you my opinion. I'm just not speaking for the industrial customer. My opinion would be that in a rate stabilization plan you should have a plan to do what you're saying, which is to stabilize the rates at the cost that you think they're going to be at. Now it doesn't necessarily mean you have to put it to $28 in the year 2002 and you only had about $12.50 before, but it would imply that you'd have a game plan to get to where you think the price of oil is going to be, charging that to your customers and having that as your base in your plan. That is not the way I interpret the, approach the problem. So you could phase it in over a few years given that you don't want to have a shock of doing it all at once, but you would not deliberately set a base that was different than where you thought the price was forecast to be in the sense of a two or three-year time horizon, some reasonable time horizon.

MR. BROWNE, Q.C.: So you're saying it should go to what is forecast, the $28, only it should be phased in over time. Is that your position?

MR. OSLER: Well, $28 may be a moving target. I think their forecast, when they filed it, was that $28 would tend to come down, so my position is, to take an example if we could without hanging me on it, if you said three years was a reasonable phase-in time period, so what do you honestly think the price of oil is going to be in three years, and after evidence the Board says, yeah, we think the price of oil in three years is going to be this, let's aim to get there in three years. Let's not set a plan that is designed to not be where we think we're going to have to be.

(10:15 a.m.)

MR. BROWNE, Q.C.: From the industrial customers' perspective, according to your evidence, they are to be in a $26 million deficit if it's based at $25 a barrel by the end of 2001. Is that a concern for the industrial customers?

MR. OSLER: I think it's $26 ... I think those were opening balances. No matter which price we set there ... looking at this table ...

MR. BROWNE, Q.C.: $26 million.

MR. OSLER: Yeah, $26 million. I don't know what the industrials think as a group but the concept of $26 million being in a fund that has to be charged back to you should be of concern to any group of customers, and what you're in effect doing is creating a mortgage account that has to be paid some day.

MR. BROWNE, Q.C.: Now, do you know how the industrial customers place this amount of money on their books, this $26 million deficit? How do they ... what do they inform their auditors, do you have any idea of that?

MR. OSLER: I have no idea.

MR. BROWNE, Q.C.: If the Board decided to collapse the RSP Plan and have the industrials pay in a period of time, how would the amount be divvied up among the three industrials, among the two paper companies and North Atlantic Refinery?

MR. OSLER: I have no idea. I think one of the troubles with this plan is that I have a lot of difficulty even with the allocations as they exist between Newfoundland Power and the industrials. The concept that we could then take it and try and divvy it up between individual customers would seem to me to introduce another level of confusion or complexity, possible. There's no rules that I'm aware of as to how they would do it.

MR. BROWNE, Q.C.: And there are three industrials being represented here. If one of the industrials left the system, is it your evidence the other two industrials would be responsible for the entire deficit?

MR. OSLER: No, not my evidence.

MR. BROWNE, Q.C.: What do you believe would happen in that case?

MR. OSLER: My view is that if you re-ran the cost of service where they, having lost an industrial customer, then the implications would be borne by the entire system and all its customers, not just by the remaining industrial customers. That's the fair and appropriate way to do it. The thought that one industrial customer is held accountable for the loss of load or benefits directly because of a gain in load from another industrial customer, I don't see any justification for that.

MR. BROWNE, Q.C.: Now, if another industrial, if another industry was to be attracted to the province and do a deal with Hydro for the provision of electrical services, would that other industrial be taking on the debt of this particular class?

MR. OSLER: I'm not as sure we have an assigned debt to the customers here, but the way I understand the scheme, if you became privileged enough to be called an industrial customer, you'd be having to pay the charges flowing from this account in a practical sense that they would charge you when they sought to recover the balances through the extra mill rate that they charge to the RSP, and if you were an industrial customer you would, as I understand the scheme, you would be privileged to pay that amount.

MR. BROWNE, Q.C.: So you would come in under the umbrella of the debt if new industry was to come into the province, is that your answer?

MR. OSLER: Yeah. You would ... I have never, I guess, thought of it from that issue, but it would be an interesting concern ...

MR. BROWNE, Q.C.: I would think so.

MR. OSLER: ... for a new industry coming in.

MR. BROWNE, Q.C.: It's a great attractor. Come in, we can give you, what is it, $26 million divided by four. Yeah.

MR. OSLER: The mill rates, according ... yeah, it would be ... I could see them giving some concern to that, yeah.

MR. BROWNE, Q.C.: So the lawyer might want to do their due diligence if they're acting on behalf of that company. In reference to the RSP, is it your evidence that the end users are ultimately responsible for payment of deficiencies in the RSP, consumers, from Newfoundland Power's perspective and the industry, from the industry's perspective?

MR. OSLER: Is your question, is it my understanding of how it works, that that's how ...

MR. BROWNE, Q.C.: Yes.

MR. OSLER: Yes. Ultimately my understanding of the intent and the way in which it's structured is that whatever amounts are in there are to be charged out on this declining balance basis to customers, end users.

MR. BROWNE, Q.C.: And is it your understanding that Hydro has the liability on its books and borrows the money to fund the RSP?

MR. OSLER: Certainly it's on Hydro's books. I don't know how you deal with it here in the sense of a, what some would call a trust account. In the Yukon the rate stabilization plan, which is called the Diesel Contingency Fund, is effectively created as a, on the books of the company, but it's under the control of the utility board, and there's no way that the company can do anything it wants with that fund without getting approval from the board, so in that sense stabilization funds are often on the books of a company but subject to the rules and directions of a utility board.

MR. BROWNE, Q.C.: Would it be on the books, from your knowledge of the RSP here, on the books of Newfoundland Power?

MR. OSLER: I have never looked at it but I would assume that that'd be the case and I could be dead wrong.

MR. BROWNE, Q.C.: Or would it be just on the, to be flow through to their customers? Is Newfoundland Power off the hook here? We have the end users, the industrials having to pay, the consumers having to pay, we have Hydro having it as a debt, which they're borrowing money. What is Newfoundland Power's function here, the middle man?

MR. OSLER: Well, from what I've been reading I gather they have their own various funds, weather stabilization and their own stabilization scheme so that they seem to, as a, if you like, a middle man, have their own additions that relate to the exercise which I'd have, I'm not familiar with, but they are sort of like a water system with a series of reservoirs. We fill them up at various stages as we go down. Eventually it does flow down to the customer, so I trust, unless somebody has found a way to syphon out expenses somewhere else.

MR. BROWNE, Q.C.: Can you go to **CA-218**? You made reference to the Yukon's Rate Stabilization Plan, and I asked there for a summary of results of survey, Canadian utilities, regarding rate stabilization plans and description of the relevant plans. Are you familiar with any of these plans?

MR. OSLER: I'm certainly not familiar with Nova Scotia, New Brunswick's or Maritime Electric's. There's nothing, according to this, in Hydro-Quebec, Ontario Hydro or Manitoba Hydro, Sask Power, Atco, (inaudible). I'm aware ... I've been aware at times, I'm not up on it right at this moment, on the rate stabilization approach in British Columbia, but I think it's very much a ... I think you've described it elsewhere in the transcript as very much an overall stabilization to do with our export earnings and a few other things like that. It's not down to customers' specific accounts, if I remember correctly. Northwest Territories, I'm not personally familiar with th is. I think some of my staff are. They haven't got Yukon here, it seems.

MR. BROWNE, Q.C.: But the Yukon has one as well, to your knowledge?

MR. OSLER: Yeah. The Yukon ... in the context of what you're talking about here, you would have found that Atco in the days when it was regulated in Alberta, I'm not sure where it is right now, Alberta Utilities typically had fuel adjustment clauses and in the sense that you're using the term here. Somebody talking on the telephone might not think of it that way but Northwest Territories, I believe, certainly Yukon and Alberta Utilities, have fuel adjustment riders which are part of your approach, and then they also have the water stabilization type of funds, which in Yukon's case is called the Diesel Contingency Fund, and the concept is very similar to the hydraulic account you have here, that to the extent that there is an increase or a decrease in diesel generation required on the main system there, due to the water availability being varying from the long-term average, then the effects on diesel costs are put into a, the Diesel Contingency Fund or taken out of it as the case may be. This particular approach was first instituted in the late '80s and has been modified and evolved, various stages, during the '90s, and it has developed a certain level of sophistication where it actually stops being utilized or stops having amounts charged to it or something or another when diesel is not on the margin in the system because the load is too low, which has happened when the major mine up there closed. So it's a fairly sophisticated approach. It is entirely separate from your treatment of fuel adjustment, which, with two utilities, their run of fuel adjustment, what they call a rider, fuel rider account, they are under direction from the Board and indeed order-in-council, which doesn't require the Board's approval, to ensure that the rider is adjusted or installed as required from time to time to make sure that fuel prices, fuel costs are being recovered, and they have got directions from the Board up there that if they sit on their hands too long after a fuel price change and don't start to reflect in the rider, the Board doesn't like that so that they ...

MR. BROWNE, Q.C.: What do we mean by too long there?

MR. OSLER: I think it would be consistent with Mr. Brickhill's evidence, six months to a year. They've sat once for a little bit longer than that and the Board didn't like it when it saw them next. And the way they do it is essentially to look at the deficit that they might have built up or, and then look at what they think the price is going to be and try and set a rider that's likely to be stable for a period of time, and what's happened in the last ten years plus, since I've been around, we have had two price, you know, spikes in all, so it's worked out. The rider came on one time and it went up by three or points on the rates. It paid off, it did okay when the price went down and they were able to get rid of the rider again, and I think it's happening again as we sit here now. We had to put a rider on recently when the price went up and I'll bet you that rider can get reduced now or pulled back again because the price has gone down lower than people thought.

MR. BROWNE, Q.C.: So it built up there in a brief period of time.

MR. OSLER: Oh, yes.

MR. BROWNE, Q.C.: It's not done year over year as here to build up an account.

MR. OSLER: No, and I think if I can ... when I look to the history here, you had a technique that went month by month with a great deal of variability. I mean, there are fuel adjustment approaches that can conform more closely with the ideas of stability than the one you've had in Newfoundland historically, so it got a pretty bad reputation given the approach you took. The one I'm talking about ...

MR. BROWNE, Q.C.: Was it pre-1985 you're ...

MR. OSLER: Yeah, yeah. It was very, very ... if I looked at some of the evidence, it really did have an effect and it would drive, I could see where it might drive a reasonable consumer a little bit frenzied.

MR. BROWNE, Q.C.: So if they had the six-month to the twelve-month period as other jurisdictions had at the time ...

MR. OSLER: Right, right, and if they tried to stabilize it to the extent they can, smooth it out rather than, you know, go to one extreme or the other.

MR. BROWNE, Q.C.: Are we at the other extreme now?

MR. OSLER: I think you've gone from one extreme to the other, yes. This one has the virtues of stability. *(laughter)*

MR. BROWNE, Q.C.: What specifically are you suggesting that the Board should do with regard to the cost treatment of the investment in the Great Northern Peninsula interconnection?

MR. OSLER: If the Board is satisfied that the project was prudent, I would recommend that the transmission facilities be specifically assigned to the rural customers.

MR. BROWNE, Q.C.: Why?

MR. OSLER: Because I think the facility is primarily almost exclusively to their benefit and not to the customers' on the rest of the system.

MR. BROWNE, Q.C.: But yet you just told me in reference to the frequency converters that the paper mills that, specific to them, but it should be deemed as common. Is that an inconsistency in your position there?

MR. OSLER: No, because the whole issue to deal with converters was that without debate or dispute they were established, the system was established on a basis that was of benefit to all and we're now dealing with the situation a long time later, trying to deal with it fairly and justly. In this case we're dealing with the establishment of this interconnection at its origin and the dispute at its essence is whether or not this is a common benefit to all the customers that were on the system before or is primarily and almost exclusively to the benefit of the customers that were previously there called rural, so we're right at the origin, we're at the nub of the issue at the start and in my opinion that goes to the ...

MR. BROWNE, Q.C.: Wouldn't you agree with me that the Great Northern Peninsula interconnection is of common usage, we have all different classes of rural customers there using that, people in the general category will have fish plants using it up there?

MR. OSLER: You have a variety of rural customers and they should all ... that's what I mean assigning it to the rural group, the group that would have paid the costs, would have had the cost assigned to them before and then to the extent they weren't paying the cost it would be called a rural deficit, it would be assigned out to a bunch of other people. That's essentially what the situation was like before you built the interconnection. The people that were living there were not paying by any means all of the costs of providing the power, so it seems to me that when you get right down to it what we're doing is shifting, we're trying to find the less costly way of serving these people and if that ...

MR. BROWNE, Q.C.: And would you say this is the less costly way?

MR. OSLER: Well that's the prudence issue. I have not been persuaded that the Company has convinced me anyway that that's the case but it's close and it's already done, and if the price of oil ... well, never mind, done. But if it has a benefit as a result of, let's assume for the moment it is prudent and does lead to some overall cost savings over time, which was my discussion with Mr. Young, then the beneficiary of that would be those who pay the rural deficit because it will simply go to reducing the rural deficit, and I'm very, very concerned that by simply looking at electrons and discussing things without looking at the whole issue here, we say that this is called common, we suddenly with the stroke of a pen assign all these costs to the customers in the integrated system, including the industrials, who, under no circumstances, would pay for the deficit if it was left as a rural deficit under the laws as they exist now.

MR. BROWNE, Q.C.: You stated in **your evidence, page nine, lines one to two, of your pre-filed second supplementary** ... I guess that's your last filed evidence. Page nine, lines one and two. We're talking about the 1.5 million which you're claiming in reference to the RSP.

MR. OSLER: Right.

MR. BROWNE, Q.C.: When did the industrial customers become aware that there were inconsistencies in the proper operation of the RSP?

MR. OSLER: I can only speak to when I became aware, and it was in the course of preparing for this hearing. I really didn't understand how the allocation mechanisms worked until we got the answers to a series of questions that are addressed in this second supplementary, so I probably put my mind on it some point in November.

MR. BROWNE, Q.C.: Have the industrial customers discussed, well, there's a billing discrepancy, I guess, with Hydro's Customer Service Department?

MR. OSLER: I do not know that.

MR. BROWNE, Q.C.: If it's a dispute between Hydro and the industrial customers concerning a billing calculation, wouldn't the appropriate forum for the discussion have been between the two parties involved, some form of alternate or dispute resolution, you might want to consider Ms. Butler's company, rather than in a public hearing such as this? *(laughter)*

MR. OSLER: I'm not aware of this ever having been a contractual matter between the parties. In my reading of their contracts I didn't see the words "RSP" once. I think the matter, this is the first time the matters pertaining to rate charges by Hydro to industrial customers have become under the jurisdiction of the Board. I guess this is just one of many issues that's on the table to get sorted out, the principles, and how you want to deal with them in the future. It may be that dispute resolution ... I think somebody was asked this earlier by one of the commissioners. It may be here, like it has been in some other jurisdictions, a very good way to proceed but it seems to take a bit of getting everybody used to what the ground rules are before you can proceed. I mean, I think there's been a long gap in time here between the last time and the current time. Once the decisions are rendered and rules are set, parties might look to being able to solve more of their disputes through that method.

MR. BROWNE, Q.C.: The industrials would have had a fair opportunity to review their bills as they're given from month to month. Is it really fair to go back now to 1992 and say, yeah, there was a mistake we just discovered in the year 2001?

MR. OSLER: It has taken a long time to get a clear answer as to how these things are allocated. It's not transparent at all from the material that the industrial customers receive along with others on a monthly basis.

MR. BROWNE, Q.C.: If we go back to 1992 and you're suggesting the RSP be revisited at a different rate, aren't you really suggesting that rates be established retroactively?

MR. OSLER: I think the rates are interim, if I'm not mistaken, with the industrials in any event, which means that they're still subject to confirmation by the Board. In the case of this RSP, I don't believe either the industrials or the Board have ever sanctioned a particular approach to the industrials. The Board didn't have jurisdiction at the time this scheme was put in place and I'm not aware of any evidence that the industrials consented to or agreed as a matter of contract to a particular scheme. So I frankly think what's been going on is that I am not the only one who's been learning what this is all about, so we've been on an odyssey to find out what really has been going on and whether it is consistent with a whole bunch of principles or not.

MR. BROWNE, Q.C.: Is it your view that the entire RSP Plan is really a form of establishing rates retroactively?

MR. OSLER: I hesitate on the word "retroactively." I think that the RSP Plan is part, an integral part of a rate structure and is reflected as such now in the application because it's in as a schedule in the rates, but I don't think its intent was to do it all retroactively. The intent was to impose charges that would be felt in the future.

MR. BROWNE, Q.C.: Thank you very much, Mr. Osler. These are our questions.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Browne. Thank you, Mr. Osler. We'll move now to counsel's questions, Mr. Kennedy, please.

MR. KENNEDY: Thank you, Chair. Mr. Osler ... Mr. O'Rielly, I wonder if we could pull up **DRW-1, page five**? This was an exhibit put forward by Hydro early on in the hearing actually and for the purposes of some of the questions I wanted to ask you about the classification of transmission in particular to demand and energy, and I think that this map will get us there, and with the assistance of Mr. O'Rielly helping us tip toe around through the geography of the province. I fully understand that you may not be intimately aware with some of the more remote locations. But as you know, one of the principal issues in this application that's at issue is the allocation of, or the classification of transmission (inaudible), and we've heard a lot of testimony and I know in your subsequent or supplementary evidence you've taken exception, for instance, to some of the positions of Dr. Wilson and others regarding that, so I just wanted to see if I understood or make sure that the differences there were clear to all. I guess maybe what I thought I would do is just start first with the summation, if you will, of your position on the issue, and if I understand it correctly initially or principally you agree with Hydro's position that generation-related costs should be classified to demand and energy in accordance with the system load factor, is that correct?

MR. OSLER: Correct.

MR. KENNEDY: And that generation specific transmission plant should be treated similar to the generation plant itself in that it too should be classified to demand and energy in accordance with the system load factor.

MR. OSLER: Correct.

MR. KENNEDY: But that, and this is where you perhaps disagree with Dr. Wilson but continue, I think, to agree with Hydro's position, which is that the grid transmission related costs should be treated all to one and not to demand and energy, is that correct?

MR. OSLER: They should all be treated as classified to demand, yes, based on the practice as I've seen.

MR. KENNEDY: Okay. So, Mr. O'Rielly, I wonder if we could just put our cursor on Cat Arm, which is up by Harbour Deep up there. Yeah. *(laughter)* The blind leading the blind here, but ...

UNIDENTIFIED SPEAKER: It's a long way from the southern shore. *(laughter)*

MR. KENNEDY: That's Cat Arm, Mr. Osler.

MR. OSLER: Okay. Where I see his hand, okay.

MR. KENNEDY: Alright. And that's a generation unit owned and run by Hydro.

MR. OSLER: Okay.

MR. KENNEDY: And as I understand it, that's a hydraulic generation plant and so being a hydraulic generation plant you would agree that the cost of that plant would be classified to demand and energy as we stated in accordance with the system load factor.

MR. OSLER: It would be my understanding, yes.

MR. KENNEDY: Okay. And as I understand it, the red line that goes from Cat Arm there down to where it ties into, and I'm going to call it the grid and you can correct me if I'm wrong, but that that line would be called a radial line, is that correct?

MR. OSLER: I'll accept it and I don't know whether, what terminology you would necessarily use here, but ...

MR. KENNEDY: Okay.

MR. OSLER: ... it would make sense it was called a radial line.

MR. KENNEDY: Okay. So for the purposes of this question let's just assume it's a radial line, I guess. So your, in your professional opinion, based on the overall operation of the connected electrical system for the Province of Newfoundland, the Cat Arm generation plant, together with that radial line, would be classified to demand and energy in accordance with the system load factor.

MR. OSLER: Let me be very careful here in terms of local facts. I don't know anything about the history of this line and whether there might be other matters under debate or (inaudible), but it wouldn't surprise me if you told me that that line had been built only because of the generation and therefore in the past it had already been classified on the same basis as the generation. Just looking at the map ...

MR. KENNEDY: Sure, and I'll ask you to accept that there's not much more up in Cat Arm other than a generation plant, so there wouldn't be much other reason to build this line from the Cat Arm plant ...

MR. OSLER: Alright.

MR. KENNEDY: ... except to provide the electricity or the energy generated from that plant to the grid.

MR. OSLER: There can be some healthy debates is all I'm saying over exactly which lines fit this description and I don't want to get dragged into it inadvertently here.

MR. KENNEDY: And I appreciate that and I'm not talking about specifics but I chose this one in particular ...

MR. OSLER: Okay.

MR. KENNEDY: ... because of it's, if it, hopefully, as I understand it, it's free of such historical tainting.

MR. OSLER: I don't know in fact whether that line has been so classified, which you haven't told me that.

MR. KENNEDY: Okay. Assuming that it is though, that it is a line built specifically for the purposes of delivering the energy generated from that Cat Arm plant to the grid, in accordance with your opinion, consistent with your report, you would for the, treat the cost of that radial line similar to the cost of the generation plant itself and split it among demand and energy in accordance with the system load factor.

MR. OSLER: Based on the assumptions you've given me to work with, yes.

MR. KENNEDY: Okay. Alright. Let's just leave that aside for a second and go to Bay d'Espoir. That's the one in the middle, Mr. O'Rielly. There you go. Where the cursor is now is generally where Bay d'Espoir is located, and actually, Mr. Osler, if you turn around you'll see then a more detailed mapping of that, just to get a better feel for what's taking place there in the Bay d'Espoir area.

MR. OSLER: Uh hum.

MR. KENNEDY: Okay. And again the Bay d'Espoir Hydro hydraulic generating station is itself, from a cost perspective, classified to demand and energy in accordance with the system load factor.

MR. OSLER: I assume it is, yes. It should be.

MR. KENNEDY: And the specific, lines built specifically to deliver the energy generated from the Bay d'Espoir plant to the grid, to the main transmission grid, would, assuming there's no historical tainting again of the line, historical factors that need to be taken into account, would be treated from a cost perspective the same as the plant itself.

(10:45 a.m.)

MR. OSLER: Well, that's the principle that you're looking at. This map, and where Mr. O'Rielly's hand is, it looks like the grid in this jurisdiction and Bay d'Espoir are very closely inter-tied. I mean, the whole system is developed with this in mind so that I don't know where there'd be any room for directly assuming that it is a part of that little line in there that's only for generation or whether it's been viewed historically as the evolution of the grid, going back to frequency converter questions and things like that.

MR. KENNEDY: Right.

MR. OSLER: So there may not be a distinction here. I wouldn't be surprised if there wasn't in this instance.

MR. KENNEDY: As I understand it though, the point of departure from your position and that of Dr. Wilson specifically in regards to the classification of costs of the transmission grid itself is that the transmission grid from Dr. Wilson's perspective should be given a demand component rather than being treated purely as energy, is that right, or vice versa, sorry, that it should be treated in part as energy and not purely demand?

MR. OSLER: I take it that that's his position but I think if you ... I think my comments were that I wasn't completely sure also as to whether he was focusing on the type of exception that we've been talking about already or whether he was talking about something much broader than that for the whole transmission system. I wasn't clear and I was waiting for his testimony to find out more about that, but if ... I've assumed that that might be the case, the way you put it, that he was implying that on the main grid, where we don't have a case of a type we've been talking about, that somehow or other some portion of those costs shouldn't be, should be classified to energy rather than all the costs that currently being classified to demand.

MR. KENNEDY: Now the transmission line, these main transmission lines that go from Bay d'Espoir over towards the Avalon Peninsula and would hook up somewhere around Goobies, which is ... Mr. O'Rielly will show you where Goobies is. That portion of the line there, going from the Bay d'Espoir hydraulic generating station to the next main point, if you will, on that section of the transmission line, you would, as I understand it again, just ignoring for a moment the historical possibility there may be some historical reasons to treat it differently, that if this was just built yesterday, for instance, that you would treat that portion of the line as being solely demand related and that you would not allot an energy component to the cost classification.

MR. OSLER: Right. If there wasn't a line going north from Bay d'Espoir and this looked like it was just a hydro plant built out, and I'm not meaning to be at all pejorative, assuming I'm from Winnipeg, I know nothing, out in the wilderness, you know, like up north, we call it the wilderness and it has nothing to do with the wilderness, believe me, but then I might have a different point of view, but when I see the lines coming through and keeping going and everything else, it looks like it's a grid serving people on both sides and all this type of stuff, and therefore would probably be the type you and I just discussed.

MR. KENNEDY: Okay. So just so I understand the rationale itself, just going back to Cat Arm again and ... the reason that you classify Cat Arm to demand and energy is because in that when the plant is built it's built to serve both, correct? It's built to provide capacity to the system but it's also built to provide energy to customers.

MR. OSLER: Yeah. If you give me a bit of tolerance here, the fact that something is a hydro plant wouldn't automatically mean it's classified this way in my professional experience. I can give you, again in Yukon, a facility that was, a hydro facility built in Whitehorse called Whitehorse No. 4, which was built to take surplus summer flows and translate them into energy and thereby save diesel. When it was built the evidence was it would have no effect on the system's capability to meet its peak in the middle of winter, so it had zero capacity capability contribution at the time it was planned and it therefore was classified by the Board entirely to energy, and I can think in theory that there could be cases the other way around where you could be classifying a lot of the cost to capacity because it's built that way. So going to the heart of your question, you go to the time period it was designed and built and what was the evidence as to what it was doing, and we go to system load factor approach as a sort of a simple way to deal with the bulk of the facilities of this nature rather than trying to go through a deal with each one and driving ourselves nuts.

MR. KENNEDY: Sure. So as I understand it, one of the underlying principles of this classification model is that the hydroelectric generating plant is often required to be built in remote locations.

MR. OSLER: Right.

MR. KENNEDY: And so the plant itself is being built to provide energy to customers in part.

MR. OSLER: In part.

MR. KENNEDY: That's normally one of the reasons why you would build a hydraulic generating station, to deliver energy.

MR. OSLER: Right.

MR. KENNEDY: And, but it's also, by virtue of being built, also provides capacity to the system as well.

MR. OSLER: Yes, and because you're using water, you will probably design the facility to get the most value from the water, so you often build up the capacity of the facility so you can pond the water at least on a daily basis so you can, like, store it during the night and run it during the day when you've got your peaks, or you might store it, you know, if you got a little bit more storage capability, you might store it during the summer in order to use it during the winter, and if you got lots of storage capability like Quebec or something, you might store it over years, okay, so you don't want to waste the water, is the principle. You want to get the most value for it. So you tend to have capacity for sure as one of the elements in what you're building it for, but it's certainly not the only one.

MR. KENNEDY: Sure. And so the classification of the cost for this purpose has a lot to do with the system planning or the system planning that took place at the time that it was constructed, is that right?

MR. OSLER: That is correct.

MR. KENNEDY: Chair, that's perhaps a good place to break.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Kennedy. We'll break until ten after.

(break)

(11:15 a.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you. You continue, Mr. Kennedy, when you're ready, please?

MR. KENNEDY: Thank you, Chair. Mr. Osler, I just wanted to just make sure I understood something that you had indicated just a moment ago when we were dealing with Bay d'Espoir plant, and I was asking you about the classification of the transmission line going from Bay d'Espoir to Goobies, that line there, and I wonder if we could make an assumption first in order to give you a hypothetical, and the assumption is that there's no line going from Bay d'Espoir up to Bishops Falls, so that for the purposes of this hypothetical what we have is the Bay d'Espoir hydraulic generating station and then this transmission line going to Goobies, and I'd also ask you to take it as a given that there's not much between those two points, and so that the only purpose of that transmission line would be to get the energy and capacity, if you will, generated from the Bay d'Espoir plant to Goobies. And if I gather correctly, you seem to indicate that that would impact on your opinion about how the costs for that transmission line should be classified. I'm wondering if you could just elaborate on that?

MR. OSLER: Well, we're dealing with a hypothetical?

MR. KENNEDY: Uh hum.

MR. OSLER: And the experiences that I've seen where people get into classifying transmission lines on the basis of both generation energy and capacity as per the generating plant have been sort of like your Cat Arm example you gave earlier, something where there's a line going in typically one direction that doesn't, on its face, have a lot of other purposes associated with it in terms of serving loads or making a system more reliable or a whole bunch of other issues that can surface, and appears to have been something that was put in place because of the generation being developed. Probably was part and parcel of the planner's thought process, etcetera, that they had to build this line in order to get the generation facility into the marketplace. The most dramatic examples I'm aware of are in northern Manitoba, the long high voltage direct current HPDC lines that come from the north classified in the way that you and I are talking about at that moment. There's a myriad of details you could get into about other types of lines and stuff like that that make one cautious about going too far with simple principles. Now, so the hypothetical examples you've asked me to think about were moving in the direction of making the Bay d'Espoir plant and the transmission line flowing and going in one particular direction from it maybe, might, under some circumstances meet these types of assumptions. Hypothetically, it might, and, but it would be something you'd get into a lot more detail than you and I are getting into here, and in the case of a system where the lines do, in fact, run in different directions and it's integral to the development of a grid for the whole island, there could, as well, be completely offsetting thought processes that would make this quite apparent to be a grid system be normally assigned on the basis of demand, so we'd have to go into a lot more detail beyond the hypothetical.

MR. KENNEDY: So just following along with that hypothetical, if there were no transmission line going from Bay d'Espoir to Grand Falls, Bishops Falls, then the transmission line that goes from Bay d'Espoir to Goobies is possible that that could get classified more in accordance with how we would classify the radial line going from Cat Arm down to the first point in the grid?

MR. OSLER: It's hypothetically possible that someone could come up with enough assumptions that would make a case for doing that. I'm not aware of any such case having been developed in practice.

MR. KENNEDY: Just going to your example in the Yukon, you indicated that it was your experience that there was a plant built in the Yukon which provided energy, I believe it was, to the ...

MR. OSLER: The one you and I were talking about before the break?

MR. KENNEDY: Yes.

MR. OSLER: It's a 20 megawatt facility on the Yukon River called Whitehorse Number 4. It was built in the 1980s entirely to take the summer run off, if you like, and used it to displace diesel when the load on the overall system was big enough or high enough to do that, so it was displacing energy and not contributing at all to the system capability at peak.

MR. KENNEDY: Okay, so then I guess that's the distinguishing feature, isn't it, that it is providing capacity to the system that that example you gave us, the Whitehorse Number 4 is providing capacity but the purpose of it being built was to provide energy?

MR. OSLER: The evidence was that it provided nothing, it was not designed to provide anything to the system peak, at the coincident peak in the wintertime because it theoretically could not. The firm river flows were not sufficient to utilize the plant, and just to bore you with a little bit more, it's called Number 4 because there were three other ones built first, and the other three are also 20 megawatts and they're sufficient to, if you like, use the river flow, if it's available, under firm winter conditions, so those 20 megawatts could probably run all year round or virtually all year round, but the other 20 megawatts when they were added on were literally only there to get the summer flow and they didn't contribute anything towards meeting the system peak at wintertime because they wouldn't meet all the tests that you'd need to do that. So in a layman's sense they provided the capability to have additional energy generated and capacity supplied, but in a practical planning sense and on review, they did not contribute to the system peak capability, which is what capacity is all about.

MR. KENNEDY: Okay. On the system peak capability and the coincident peak, I had a few questions about that because there's parts of it that I'm afraid I'm still a bit muddled on. There was a statement you made during cross-examination by, I believe it was counsel for Newfoundland Power, regarding the peaks in the system, and my notes indicate your statement was something in accordance with that this system has only one peak per year, and when it occurs is irrelevant?

MR. OSLER: Okay. It may have been with Hydro, but anyway, okay.

MR. KENNEDY: Okay, and I guess from a lay person's perspective, it's always going to be the case that there's one peak in the year for any system? In other words, it seems like the methodology employed is to look at the system peak on a day-by-day basis, determine when the system peak occurred and then calculate what the coincidence is for the different customer groups during that peak period, correct?

MR. OSLER: I can understand that perspective. What I'm getting at with the concept of two system peaks, I think Mr. Brickhill raised it first, in the American situation they had seen the evolution of the summer peak, if you like, with air conditioning and its surpassing even to the south of Manitoba, surpassing the winter peak, but I think the planners, at least in the northern part of the States, would still say it hasn't surpassed it by such a level that they want to just say they've only got one peak. They literally worry about two peaks in their operation of the system, one in the summer and one in the winter, so it's in that sense of the word. Technically there may be one of them that's always going to be bigger any one year, but they would probably say that to plan and design this system they've got to be conscious of these two system peaks when they're building up their capability.

MR. KENNEDY: So that if we just go with a hypothetical and we say that there's 1000 megawatt peak that takes place in the month of January and an equal peak that takes place in the month of July.

MR. OSLER: Uh hum.

MR. KENNEDY: And all other months in the run of the year are substantially less than either one of those peaks.

MR. OSLER: Okay.

MR. KENNEDY: Then, as I understand it, we would clearly have a two peak a year and that one of the underlying presumptions is that the participation, if you will, by the various customer groups, in contributing to that peak, may be different in the January month than it would be in the July month?

MR. OSLER: Right.

MR. KENNEDY: And that would drive in part the rationale for why you should go with the 2-CP as opposed to a 1-CP?

MR. OSLER: Right, and in the hypothetical example what's important is that there is a peak in the winter. We may or may not have it happen in January. It may be December, it may be February or whatever, and there's a peak that's going to occur in the summer, we're fairly confident of that. It may happen in July, it may happen in June, it may happen in August. In that sense, to put it back to the words you gave in the beginning, the fact that we've got these two peaks is what really matters. Whether they occur in the months that you and I are talking about or in a nearby month, to paraphrase what I said earlier, is irrelevant.

MR. KENNEDY: And so let's go with another ... and so first of all, in that hypothetical, as I say, the underlying presumption is that the customers contributing to those peaks are likely to be different, at least proportionally, because of the fact that it's over two completely different time periods, and the mix would be different. The industrial classes may be using energy more in the winter and less in the summer or vice versa, and Newfoundland Power, for instance, may be using more energy in the winter and less in the summer or vice versa, and that that ... those changes that take place on a seasonal basis are what provide at least one of the rationales for why you would go through the effort of calculating a 2-CP allocation?

MR. OSLER: Right. I mean, you would assume that that's possible, so the effort would be undertaken in case those issues arose in order to make sure you were fairly treating the different customer classes. There would be other issues that arise when you start going beyond 1-CP, and they would be, you know, how much importance do you ... is there equal loss of load associated with each one or is one more important than the others, and do you, therefore, weight each of the two peaks equally or do you give more weight to the one in one time period versus the other? Those are other questions that might arise in the hypothetical.

MR. KENNEDY: And just to follow that for just ever so briefly, that would be impacted in part by the mix of how the energy is actually produced or the capacity is produced at that given month between hydrological production and thermal production?

MR. OSLER: It might be. I mean, you might have a lot of water around in the summertime but not much in the winter, and that might change your assessments. It might also be the nature of the customer loads or all the things that could contribute to probabilistic calculation.

(11:30 a.m.)

MR. KENNEDY: Now, just taking another hypothetical. If we had peak of 1000 megawatts in the month of January and an equal peak of 1000 megawatts in the month of February and all other months had substantially less ... place substantially less demand on the system than either one of those months. Would we use a 2-CP method then at that point, and how would you allocate between those two months?

MR. OSLER: I think we would be ... we were talking a hypothetical. In practical terms, when you get two months side by side and a peak happens to occur of the same order and magnitude in each of the two months, you have a ... you would assume you'd probably have a common set of conditions and circumstances affecting both the way in which you supply the energy and the nature of the customer load, so that ... and it may happen that it's occurring that way one year and a different way another year, etcetera. I would tend to think of that more as examples of the one peak system rather than two peaks, for the reasons you've gave me, that when you get them well spread apart, summer versus winter, you do get naturally a bunch of concerns about different characteristics for the generating system and different characteristics for the customers that make you want to think about examining them very carefully.

MR. KENNEDY: And so if, using that same hypothetical, we had a peak of 1000 megawatts in the month of January and 1000 megawatts in the month of March and all other months paled in comparison to those two months, then we start down towards the road of going to a 2-CP, potentially?

MR. OSLER: Probably not. It'd probably all be called the winter. I mean, what happens in practice, what we have to remember is that when we do the cost of service we're doing it on a prospective basis and for the purpose of these hearings, so look at what the utility that's preparing the cost of service does, it doesn't predict a roaming peak, it predicts it in a certain month using whatever forecasts it's received, and we tend to go with that for the purpose of allocating. If it actually turns out to be a different month, the underlying assumption is that probably we're treating everybody still fairly if we ... the same group of characters that would have been there in the month that the utility forecasts are probably there in the other month nearby when a peak occurs, so we don't need to get ourselves in a lather or we missed a month. We trust, if you like, in terms of an operating assumption that we've still dealt with everybody reasonably fairly.

MR. KENNEDY: Now, again, during your cross-examination by, I believe it was counsel for Newfoundland Power, there was an exhibit which provided the ... that was the seizure inducing exhibit, although I thought it was more coma inducing than seizure inducing, but it showed the peaks on a month-by-month basis historically, and one of the things that struck me when I was looking at that exhibit was the fact that really there's an awful lot of similarity ... or that's probably not the right word. The difference between the peaks on a month-to-month basis is, in many cases, quite small. If you look at, for instance, the four or five winter months, December, January, February, March, that it may be 1310 megawatts one month and then it may be 1250 or 1275 or 1285 in a corresponding month, that there isn't a dramatic difference between the peak in one month than the peak in another month, and that that holds true for several of the months in the run of a winter, and I'm wondering wouldn't that then imply that, well, really what we have is a whole peak that takes place over the run of the whole winter? And is it still a safe bet then from your perspective, to assume that the mix of the contribution by different customer groups over the whole winter is consistent, and therefore you can still stick with the 1-CP?

MR. OSLER: I think in terms of issues about mix I haven't seen evidence that would suggest that that causes a big problem. What happens when you go from 1-CP to 4-CP is you do more averaging, and that tends to, as one of the counsel was asking me, tends to lead you inevitably, as you extend the time that you average over, to taking it away from being a capacity peak more towards and average demand, which frankly, takes you away from the whole point of capacity pricing, so I think it's not so much that the mix changes, it's that the net result of what you're doing tends to move away from the point of the exercise, which is capacity allocation.

MR. KENNEDY: But when ... and if I understand it correctly, again, one of the underlying rationales of the CP allocation is that it plays into the system planning itself, that when Hydro plans its system it must take into account what the coincident peak will be?

MR. OSLER: Right. The amount, not so much the date.

MR. KENNEDY: That's correct. That it's forecasting that at some point in time during the year that it will have to have the capacity to produce 1315 megawatts of energy?

MR. OSLER: Correct.

MR. KENNEDY: Now, from a system planning perspective though when Hydro is actually designing its system wouldn't it look to more of a demand average rather than that single coincident peak in the design of its system?

MR. OSLER: Well, it's a question you would put to their planners, but it's my expectation that their answer would be no. In terms of dealing with the capacity related issue, they'd better think about the capacity that could occur at any one moment and the worst moment in the year, because if they don't supply it they're going to have trouble. When they're thinking about their energy costs they should think about the duration of the system requirements at various levels, because if it's going to be at such and such a plateau for a long period of time then you're using high cost fuel to meet it when you could use a cheaper energy source if you planned for it, then you'd think about that, but that's literally energy planning as distinct from capacity planning in the sense that you and I are using the term and what would apply to a coincident peak allocation debate.

MR. KENNEDY: Okay. Now, I take it you're aware that Hydro classifies its turbine generated energy ... or turbine generated electricity, just for the lack of ... for the word, just to avoid the classification words for a moment. That it classifies all that to demand rather than energy?

MR. OSLER: I gather, yes.

MR. KENNEDY: And is my understanding correct that the reason that they do that is because, well, the turbine is actually being built to satisfy those peaks that occur, and therefore, the turbine is specific to providing demand, that's the rationale that Hydro is using?

MR. OSLER: I haven't reviewed it in detail, but I would assume that's their rationale, that they'd never run that turbine unless they had a very ... either an emergency or a spike at the peak.

MR. KENNEDY: Okay, and a turbine you would normally locate close to the source of close to where the demand is required, wouldn't you?

MR. OSLER: All things being equal. I mean, you might have one out in the end of a long line in order to give stability in a line shutdown or something, but since you can move the turbine very easily you'd tend to think you might put it where the load is.

MR. KENNEDY: And you'd put it close to where the load is, presumably, because you can and that would avoid just load loss over the lines themselves, correct?

MR. OSLER: Correct.

MR. KENNEDY: And that's the principal difference behind the fact that you've got a turbine being placed close to where you need the load and it has a specific use of satisfying demand during peaking requirements, and so it gets from a cost allocation, all allotted to demand? Am I right so far?

MR. OSLER: Yes.

MR. KENNEDY: Okay, and that in the case of hydraulic generating it's often remote from the load and it's being built both for the purposes of providing capacity to the system but also to generate energy?

MR. OSLER: Correct, but you have to keep in mind that we're focusing a lot on generating units and the different reasons as to why you could classify them differently, but my understanding is that historically the classification of transmission plant was really done on the grounds that the planners looked at the transmission facilities and said we have to build them and design them to meet their peak and they weren't interconnecting it with generation, okay, so in some of my conversations with people that are very heavily oriented that way, I get told, you know, very simple, it's transmission line. We build it to meet the peak, and what's the issue? And you have to get to the stage and discussion with such people to even bring generation into bear. They just say it looks like a transmission line, it is a transmission line and it should be treated this way. I mean, we are adding a level of thinking and everything else to this to tie the generation to it in the first place. It's the exception, not the rule, to think about generation when trying to classify a transmission.

MR. KENNEDY: Okay, and I understand your position. I guess what I was just ... just to finish the thought. The difference between them is that in the case of the turbine there's no need to build a transmission line to get the demand delivered to the load?

MR. OSLER: Correct.

MR. KENNEDY: In the case of the generating station there is normally a requirement to build a transmission line to get the demand driven to the load, delivered to the load?

MR. OSLER: Well, you're talking about the hypotheticals with hydroelectric generation?

MR. KENNEDY: That's right.

MR. OSLER: And there'll be a certain degree of that, I suppose, with every single plant. Which just to drive the point home, I mean, you put a coal plant near the load but it wouldn't necessarily be in the middle of the city, you'd put a nuclear plant maybe a little bit further away. I don't think you'd find planners getting into trying to classify the transmission hook ups to those plants. It's something separate than transmission grid, so you really have to go outside the norm, like a very distant hydro generation plant, in my experience, anyways in Canada before someone can overcome the natural tendency to say transmission is classified as demand, to say, no, no, this particular transmission is different, it is so clearly different that we do have to deal with it differently. If you get my drift?

MR. KENNEDY: No, I understand, and so in some cases, at least in some hypothetical cases, a transmission line can be classified as both demand and energy?

MR. OSLER: Correct.

MR. KENNEDY: Okay, and that it's a case of the system planning, the purpose of the generating plant and its remoteness from where the energy is actually required?

MR. OSLER: Correct.

MR. KENNEDY: Okay. That's all the questions I have, Chair. Thank you, very much, Mr. Osler.

(11:45 a.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Kennedy. Thank you, Mr. Osler. We'll move now to redirect by Hydro, please, Mr. Young?

MR. YOUNG: My witness.

MR. NOSEWORTHY, CHAIRMAN: Early morning. Yes, Mr. Hutchings, please, if you could proceed with your redirect?

MR. HUTCHINGS: Yes, thank you, Mr. Chair. Firstly, Mr. Osler, I just want to clarify something in the transcript that doesn't seem to read in accordance with my recollection. Looking at the transcript, if you we can bring it up, of November 29th, 2001, at page 45 in the electronic version at lines 7 through 9. You were discussing there the question of the prudence of the Great Northern Peninsula interconnection, and the sentence at the end is recorded as followed, "In order to do that," and you're speaking there of the investigation of whether or not the costs should be disallowed, "you would need a lot more information, none of which was asked, and not offered." Can you just explain for us what you had intended to say, what you did say, perhaps, at that point?

MR. OSLER: Can I just read the ...

MR. HUTCHINGS: Sure.

MR. OSLER: I would think it would be in order to do that, which is to do that type of assessment, you would need a lot more information, probably some of which was asked and not offered or a lot of which was asked and not offered, one of those two might have been what I'd said, because we did ask questions of the applicant to give us an assessment of the situation with and without the line going forward and they declined to answer that. It was asked in many different ways and declined in a fairly consistent way.

MR. HUTCHINGS: Okay, so the intent was to say that there had been some questions asked but information, not all of the information you would need to reach a conclusion was received?

MR. OSLER: Correct.

MR. HUTCHINGS: Okay. That's fine. I just wanted to turn now to your discussion on Friday with Ms. Butler as it related to your second supplementary evidence, and specifically, the effects on the RSP of the continuance of Albright and Wilson and Royal Oak Mine loads in that plan for the purpose of calculation of the RSP. I don't think we necessarily need to go to it, but it's around page 28, I think, onwards, of the transcript of November 30th. You had discussed with her the significance of the number which was included in your evidence, which was a number of $415,810 which she suggested, at page 31, around line 37, was the amount that the industrial ... according to your suggestion, that the industrial customers balance would be worse off, and your answer there at line 39 goes on to say that was the number used as for an example on page 9 and it appears to be incorrect. It doesn't go to the principle on page 8. Can you explain for us the significance of that number $415,810 and how it comes to be calculated and used for the purpose of the RSP?

MR. OSLER: I think there was an exhibit Ms. Butler ... or a piece of paper that was put on the record that showed that this number reflected, $451,810 reflected the loads that had been forecast for Albright and Wilson and Royal Oak and the rate that was assumed in the ... the rate that is charged, sorry, today to industrial customers, 19.34 mills, so that the application of the forecast and that rate lead to the calculation of $415,810, so that's clear. How it is applied in the RSP is, I think, where it isn't clear.

MR. HUTCHINGS: So have you prepared a further schedule to try to illustrate what happens with that number under the provisions of the current RSP?

MR. OSLER: Yes.

MR. HUTCHINGS: Okay. I'd ask to have that circulated now, Mr. Chair.

MR. KENNEDY: IC No. 6, Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you.

EXHIBIT IC-6 ENTERED

MR. HUTCHINGS: Perhaps you could just outline for us the origin of this exhibit, **IC-6**, which is headed Impact of Albright and Wilson and Royal Oak Mine on NP and IC RSP and indicate how far beyond where we were on Friday this particular exhibit takes us?

MR. OSLER: Well, this exhibit compares with **NP-11**, and **NP-11** had put in the numbers and in columns one, two and three. It hadn't bothered to show total actual, but it doesn't matter. It had showed the revenue mill rate and it showed the revenue loss as totalling to $415,810. It had showed the last set of columns, the net mill rate and the numbers in the last end of the page. It did not show the cost of Holyrood mill rate and the cost savings which totalled the $442,466, so that's sort of where we were on Friday. The point that needs to be understood is that the RSP treats the revenue amount, the $415,810 differently than it treats the cost savings amount, which is the $442,466, as regards allocation. The revenue loss is directly assigned to the class that was forecast to have paid the revenue, in this case, industrials, so it's our foot down below here in amounts allocated, under the revenue column of $415,810, all of it is allocated to IC and it's a charge to the RSP because that's a deficiency in revenue from the point of view of Hydro.

MR. HUTCHINGS: It might help us, I think, at this point, to look at **IC-271**, revised. Okay. The page 2 of that response shows the summary plan balances?

MR. OSLER: Right.

MR. HUTCHINGS: And I think this shows us an allocation both of costs and revenues to the two plans?

MR. OSLER: Right, and the point of this answer was to explain the issue that goes beyond what we were talking about on Friday, the allocation of these numbers, and it shows you that the whole answer starts from the costs versus the revenues. When we're talking about Albright and Wilson and Royal Oak they are part of Column 2 here under industrial island. They are part of the ... they went into the calculation of the so-called revenues, and there's a table that it refers to in here that does it in more detail, but you wouldn't understand ... they don't show you the individual customers in the table, but if you went back to all the sources, the Albright and Wilson, Albright and Wilson and Royal Oak numbers are in the calculation.

MR. HUTCHINGS: Okay.

MR. OSLER: Okay, so that's the first element, and it's also shown, without having to jump back and forth to it, at page A-2 of my final November testimony where the revenue component is shown in one part of the page and the fuel components, as they're so-called, are shown on the other, and the breakdown that you see here, the 952,251 is shown there and the 78,183 ... I showed 184, but it's shown there, so I was using this exhibit **271** to document this stuff in the appendix.

MR. HUTCHINGS: Okay, and while we're dealing with the revenue question, if we could look at page 4 of 7 of **271**. This shows, I believe, how the revenue adjustment is calculated?

MR. OSLER: Correct.

MR. HUTCHINGS: Okay.

MR. OSLER: And it shows that they are effectively looking at the current year actual sales for industrial customers 1,245,157 megawatt hours and they're comparing it to the 1992 test year sales, 1,249,200 megawatt hours. In the test year sales will be the 21.5 ... 21,500 megawatt hours from Albright and Wilson and Royal Oak. Of course, they will contribute zero to the current year sales. The variance is then charged at the going current energy rate, which in the current year we're talking about there is 1.934 cents or 19.34 mills, and that is then credited to or charged to the RSP for the industrial customers in one case and the NP in the other.

MR. HUTCHINGS: Okay, so the one that we're looking at here shows current year sales actually being below the test year sales, correct?

MR. OSLER: Correct.

MR. HUTCHINGS: Okay, and that gives rise to a negative revenue variation, which means what in terms of the charge to the IC RSP?

MR. OSLER: It means that it becomes a charge that builds up the balance.

MR. HUTCHINGS: Okay.

MR. OSLER: And that's based on the rate that's in that year. That isn't necessarily the rate that was in the test year, for example.

MR. HUTCHINGS: Right, okay. If the test year's sales shown on this page 4 were reduced by the 21.5 million kilowatt hours that are assigned to Albright and Wilson and Royal Oak Mines, what would that do to this calculation?

MR. OSLER: It would reduce the ... it would take away from the variance 21,500 megawatts, 21,500 megawatts, so it would lead to a positive variance, which means that the actual test year sales would have been greater than the ... sorry, the actual current year's sales would have been greater than the test year, and that would have ended up with some money being taken away from the fund, credited.

MR. HUTCHINGS: Okay, so instead of there being monies charged against the industrial customers, there would, in fact, have been monies credited to the industrial customers in the RSP?

MR. OSLER: Right.

MR. HUTCHINGS: Okay. Alright, and that, to go back to page 2 then shows up on the summary, the negative 78,000 increases the balance in the RSP, whereas without Albright and Wilson there'd be some positive number there and reduce the balance, correct?

MR. OSLER: Yeah. To be very simple, you'd take Column 2 away from Column 1, but because Column 2 is negative it actually means it's added.

MR. HUTCHINGS: Right.

MR. OSLER: Okay.

MR. HUTCHINGS: But without Albright and Wilson there'd be a positive number there so the balance would, in fact, be lower?

MR. OSLER: Yeah.

MR. HUTCHINGS: Yeah, okay. Getting back then to **IC-6**. We've looked at the revenue loss and how that is, in fact, assigned. Do you need to refer further to that for the purpose of **IC-6**?

MR. OSLER: No.

MR. HUTCHINGS: Okay. Now, let's look at the cost side.

MR. OSLER: The cost side, if you look at the **IC-271**, you're seeing costs there. It doesn't tell you a great deal about them. The costs, if you went to, I think, page 3 of **IC-271** you'll see a bunch of complicated numbers. You see Column 1, row 1 is your to date fuel cost, and you see a number at the very end $12,237,007 from the RSP report, okay, and maybe with your great technology, Mr. O'Rielly, we can go to my November 25th testimony, page A-2. Okay. Keep going. There. Do you see the number for fuel components and you see the full year 2000, which would be the December 31 time period that we were just talking about, and you'll see hydraulic, fuel and load and you'll see rural rate alteration. If you were to add back the negative $880,000 per rural rate alterations and the $11,357 you'll come to the total that we just discussed of about $12,237,000 that's in that **IC-271**, so when they talk about a year to date fuel cost they are talking about the things that people have asked me about that come out of the RSP reports, the hydraulic, the fuel and the load variations as they affect costs, all added up together. They are not talking about yet the rural rate alteration. That's a separate item, so you have to sort of see how the two relate to each other. To get back to **IC No. 6**, the savings from not having had Royal Oak and Albright and Wilson go into what you're seeing here as cost, cost to IC savings for the year, 83,095 in my table at page A-2.

MR. HUTCHINGS: Uh hum.

MR. OSLER: They are part of all that calculation that went in there because the load was less than forecast, we used less energy than forecast, therefore we saved some Holyrood fuel costs is the assumption, and they go into that calculation there. The point is that when you study the allocation mechanism in **IC-271** all of these costs from all of these sources and all of these different means are all lumped together and treated as a lump.

MR. HUTCHINGS: So ...

(12:00 noon)

MR. OSLER: Maybe we should go back to **IC-271** now, page 3. Okay. Maybe go to page 5, Mr. O'Rielly. Page 5 ... well let's just do these two steps. Go back, please, to page 3? At the very top there, the $12,237,000 under Column 12, row 1, gets adjusted slightly by something to do with the rural rate alteration, but that number is not what's going to be carried forward, so go back to page 5 now. At the very top of this page they are showing you, in terms of how you do a cost of service, the test year costs are broken out by production demand, which you've just been talking to me a great deal about, the costs that get allocated only on the basis of demand. Production and transmission energy, which gets allocated among customers only on the basis of energy. Transmission demand, which gets allocated only on the basis of demand factors. Distribution and account costs which are, frankly, not relevant to IC customers and they're largely, I think, entirely to do with rural, and then specifically assigned customer costs which are specifically assigned to certain groups, particularly NP and industrials, so that's how you'd come up with your cost of service. They have made a very small alteration to this in the second line to do with, I gather, the Great Northern Peninsula's impact. Look at the number on line 3 under Column 2, there's your $12,237 gain. That's all that fuel cost absent the overall rate alteration, so that's where it comes into the calculation, it's entirely assigned to production and transmission energy and it is allocated out to the customer classes based on the rules used for allocating that, and if you look down through lines 5 through 8 under Column 2 you see the allocators used. 72.23 percent is allocated to Newfoundland Power, 21.188 percent is allocated to industrial customers, .0658 is allocated to rural island interconnected, and the rationales for those, as they say here, are translated to you on page 6, if you could just go there briefly, at the very top of the page, megawatt hours at generation. They've shown the sales forecasts for the three customer groups, they've added on losses to do with getting it back to the generator, they give you megawatt hours of the generator and that's how those ... that's where those percentages come from.

MR. HUTCHINGS: If we could just go back to page 5 for a moment, and highlighting again the 12,237,000 under Column 2 at line 3. That number, if I'm understanding you, has included within it, the value of the oil that was not burned because the Albright and Wilson and Hopebrook loads didn't have to be met, is that correct?

MR. OSLER: That's correct.

MR. HUTCHINGS: Okay, so the savings from not having those customers on the system are embedded in that number?

MR. OSLER: Correct.

MR. HUTCHINGS: Okay, and then that number gets allocated in accordance with this page?

MR. OSLER: Yes. Column, rows 5 through 8.

MR. HUTCHINGS: Okay, and that, I think, brings us directly back to **IC-6**, does it not?

MR. OSLER: Correct.

MR. HUTCHINGS: Okay.

MR. OSLER: So you'll notice on **IC-6** that we repeated the 72.231 and the 21.188, the numbers that come from page 5 of **IC-271**, Column 2, rows 5 through 8. We've shown them alongside the NP, IC and rural, and then we've taken the $442,466 worth of Holyrood cost savings and allocated them among the three customers classes using those percentages, so that $319,597 is allocated to NP from the cost savings associated with Albright and Wilson and Royal Oak, 93,749.7 is allocated to the IC and 29,114 is allocated to rural.

MR. HUTCHINGS: Okay, so the bottom line here is that IC basically stands to all the revenue loss but receives only 21.1 percent of the cost savings, is that correct?

MR. OSLER: That's correct.

MR. HUTCHINGS: And your box on the lower right-hand corner, what does that tell us?

MR. OSLER: That's just netting it by class, everything we've been talking about on both the revenue and the costs, NP ends up with a benefit of 319,597.6, IC as a reduction ... or come into its account in the RSP for 322,060 and rural, as a reduction to the RSP amounts by 29,114, and that'll get allocated out through the rural deficit.

MR. HUTCHINGS: Okay, and this exhibit **IC-6** is designed solely to identify the effects of leaving Albright and Wilson and Royal Oak Mines in the cost of service numbers for 1992, assuming everything else remains equal?

MR. OSLER: Correct, and it just is designed to try and highlight the extent to which the RSP reports, which, in fairness to Ms. Butler, do only show the sort of mill rate type of assumption to the far right, do not give you a great transparency as to what the allocation procedures are and how they are different for the costs versus the revenues.

MR. HUTCHINGS: Okay, so that 1.01 mills that you and Ms. Butler were discussing the other day goes directly into the summary sheet, but all these other costs, take a more circuitous route but come back to it in the end?

MR. OSLER: Yeah, they do.

MR. HUTCHINGS: Okay. Thank you. Now, you had a brief discussion with Mr. Browne concerning the frequency converters, and one question that he put to you was what would happen if the customer, and I think effectively we're talking about Corner Brook Pulp and Paper, were to cease operations. On the assumption that that were to happen but the generating facilities continued to exist at Deer Lake producing 50 cycle power, would you see a use for frequency converters?

MR. OSLER: Yes.

MR. HUTCHINGS: And why would that be?

MR. OSLER: I guess you'd like to make use of the power that is available from Deer Lake, particularly since it isn't being used to feed the mill and the rest of the system of the converter would have a value.

MR. HUTCHINGS: Okay. Thank you, Mr. Osler. Those are all my questions on redirect, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Hutchings. Thank you, Mr. Osler. We'll move now to Board questions. If I could ask Commissioner Powell to begin, please?

COMMISSIONER POWELL: Thank you, Chair. Good morning. I don't have a whole lot of questions. The notes I had, I think they got covered pretty well. I just have a couple of things I noted when I was reading your pre-filed testimony the first time around, and on page 1 on line 31 to 35 you ... when you were doing your introduction you talked about review. You made a reference to, "However, given the volume of the responses and the limited amount of time that has been available for us to review them, this review has been severely restricted, and furthermore, several key responses filed to date by Hydro failed to produce sufficient information as yet to usefully answer the questions poised." Is that a norm? I'm struck by that in the sense that I'm just wondering. I sort of got the impression that this is not normal for an intervenor like yourself to be in a position not to be able to respond.

MR. OSLER: I came into this exercise maybe later than some when I was retained, just before the first information requests were put in, so I didn't have ... coming in with no background at all, particularly subjected here, but there's a lot more information here in this hearing, I think is fair to say, than one would normally see, because of the history, I suspect. The only case I've been personally involved in which had more than this, I think it has ... I was trying to say the day, I think it's 120 hearing days, was the electricity costing and pricing hearing of Ontario Hydro in the late `70s, and that was a generic hearing on costing and pricing and it went on for a long time. Most hearings, a week to three weeks, two to three weeks and the volume of information wouldn't build up like this, but then the hearings tend to occur more closely together so the parties get more familiar with what's going on and they're not involved in going back over the history, so there are some unique features, perhaps, to this hearing and its circumstance and to my involvement. As to lack of responsiveness, I think intervenors the world over complain from time to time, about lack of responsiveness. I don't think I would say that's unique. I think in general the Applicant has been ... probably feels they've been more than responsive and they've answered an awful lot of questions and wish these silly intervenors wouldn't ask them any, and that's, since I work for utilities from time to time that's also not unusual in terms of a perspective on that. I think each hearing and each process has to sort of figure its own water level on this.

COMMISSIONER POWELL: Okay, so I just ... this is everybody's responsibility, okay. Excuse me, I'm just going through my notes here. I just ... one of the other questions, since you've been involved in a number of hearings, the process in which Hydro has gone through to prepare their cost of service, the evidence was that there's a cost of service model that is separate from their financial data model. Is that standard?

MR. OSLER: Yes, I noticed your question of them on it. It tends to be standard. I guess the only explanation I can give, to keep it at a very simple level, is that it really is a one off exercise that's done for a rate hearing more than for normal day-to-day business, and it has a whole bunch of rules and stuff that only a handful of people usually in a utility understand, and so it tends to be a custodian of a few people and it's run on a separate model, and that happens, everywhere I've been that tends to be the case. It takes all the costs and pulls them together in a very specific way that doesn't fit into the normal, everyday thinking of the company. If you have cost accounts of the old days, rather than business units, I guess there's a little bit more interrelationship between the two. Business unit accounting seems to raise another level of issues, but I'm not ...

COMMISSIONER POWELL: Do you have problems with that?

MR. OSLER: No, I don't have it, per se. I mean, it's ... in my personal life it's not uncommon that when you start to get into certain type of thing you only do occasionally you tend to create a one of system. You always like not to every time you have to go through it, but, the effort to try and design the perfect interface seems to more trouble than it's worth.

COMMISSIONER POWELL: No fear of loss of data?

MR. OSLER: Oh yeah, yeah, there's lots of risks that go with it, and it may be that, you know, somebody comes along 20 years from now will say that what I'm saying right now is ridiculous, we've all found a way to do it, and with modern technology and modern computing, somebody has found a way to make it simpler. I'm just saying over my career it's been the other way around, and they haven't done it yet in any place that I've been dealing with so far, and they're, you know, with the deregulation, they're tending to move away from doing this. I can think of a few cases where I'm wondering what's going to happen the next time I see a hearing in the Yukon, when people used to rely upon Alberta Power in Edmonton to do this type of stuff, and I don't think Alberta Power has got people around who are doing cost of service. It's a different environment, so I mean this may become a dying art.

UNIDENTIFIED SPEAKER: You wish.

COMMISSIONER POWELL: So are you familiar with the financial system that Hydro has now, the JE Edwards?

MR. OSLER: I am not intimately, no, at all.

COMMISSIONER POWELL: So you don't have any views on whether that's, other utilities use it or ...

MR. OSLER: I've heard of others using it but I'm not sure, but I don't have anything useful to offer you.

COMMISSIONER POWELL: And so you think there are some merits to doing some sort of (inaudible) resolution mechanism in terms of since we have a small customer base?

MR. OSLER: I'm not sure whether it specifically relates to whether you've got small or large. Other jurisdictions in British Columbia and Alberta and places have used, have had settlements in hearing processes. I think the BC Utilities Commission does a lot of it. In Yukon they did it once and they're not sure they're going to do it again.

Sometimes in smaller jurisdictions the intensity of some of the disputes are more intense than they are in larger ones, so I think it merits serious consideration. I can see the need to get beyond this hearing before people would ... we'd want to see what the Board's rules are and then work within them rather than trying to sit around the table trying to figure out what the rules in the system are.

COMMISSIONER POWELL: Okay, that's all my questions, Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Commissioner Powell. Commissioner Saunders?

COMMISSIONER SAUNDERS: I have no questions.

MR. NOSEWORTHY, CHAIRMAN: No questions. Commissioner Whalen please?

COMMISSIONER WHALEN: Thank you. Good afternoon, Mr. Osler. I just have one question that really follows up from Mr. Hutchings taking you through your evidence on Friday when you first took the stand and when you were talking about the Rate Stabilization Plan, and the options and implications of. You mentioned that in terms of the recovery mechanisms for the balances in the RSP, and that there might be other options we could look at in place of the ... I think the declining balance method was the way you categorized the existing recovery method, but I wonder if you could expand on that for me a little bit in terms of what other options might be there?

MR. OSLER: Well, the most straightforward options would be ones that don't let it decline, the declining charge through decline necessarily, but try and clear the account off, so that if you went over a certain level, they sort of lock in a minimum amount to be recovered, and don't let it decline so that you really bring the thing down over time more quickly. Those are techniques that you would use for an account of a type that you have here. If you were doing a fuel adjustment type of approach, it could be quite a different approach to start with. It could be one of setting a number that the utility thinks will recover the fuel cost over, that's been built up to date, and where they think the fuel price is over a period of time, and then reassessing it to see where they were going every two years, or a year, or something like that, and in some cases the fuel rider may vanish completely for a while, and other times it may be on, or ... and if the fuel rider stays around for too long, at least it's passing through what they think to be the current fuel price, thus recovering some of the background *(phonetic)*. But if they went to a general rate application, typically that account would be severely affected because you would adjust all of the rates in the rate application to reflect the current fuel price in the normal situation, and then you'd just worry about getting rid of the balance, and it might be in the account over a short time period, and the rider would vanish when you get rid of the account. That's sort of the Alberta/Yukon type of approach.

The water stabilization accounts that I've seen don't tend to pass through rate charges to customers. They tend to be between the utility and the account, so they simply keep the utility whole, and if the account goes outside a certain range, then you might have to put a rider on either to rebate or to collect in order to put the account back. I think you had that experience with your water account back in the eighties. So I mean there are different approaches you would use that seemed to work that don't build up an account quite of the magnitude we've seen here. But there's, you have to do various things to tackle it, and not just what you've recovered through recovery charges, but how you set those charges ... the different examples I gave get to setting the charge based on where the price of oil is now rather than something else.

COMMISSIONER WHALEN: So in terms of the separate from a fuel rider charge, and those kinds of mechanisms, if we look at the existing plan with existing balances, your suggestion would be that we look at recovering those balances quicker?

MR. OSLER: Or let's put it this way, let's say recovering them quicker, but perhaps not through taking out one third, more than one third, but making sure that that amount doesn't keep declining as you go forward so that you get somewhere quicker, do you know what I mean. I'm not necessarily ... there's a lot of different judgements go in to how fast you should try and get from where we are today to where you should be, but the declining balance technique has a tendency to make sure you never get there, just by definition. It keeps going down, sorry, as you move forward, so it seems to me the key would be to say I want to get there in five years or something like that and set a number that is likely to get the account down to close to zero in that time period.

COMMISSIONER WHALEN: So instead of looking at the balance and just dividing this year by one third and then continuing on, you look at your end point and then back up.

MR. OSLER: Right.

COMMISSIONER WHALEN: And what do we have to do to get to that point, so it's a different, just a different approach.

MR. OSLER: It's a different approach.

COMMISSIONER WHALEN: The mechanics might not be very much different, I guess.

MR. OSLER: Right, but it's, if you were trying to amortize an amount over a period of time you'd approach it very simply that way and say I want to amortize it over five years. If I've got a problem with the account growing or shrinking during that time period then you add that to your thought process, but you sure as heck have an incentive to not have the account growing while you're trying to get rid of it in five years, you know, that type of thing.

COMMISSIONER WHALEN: Okay, thank you, that's all I have, Chair. Thank you, Mr. Osler.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Commissioner Whalen. Good morning, Mr. Osler, thank you very much for your evidence and your testimony and I just have, I have three questions, and actually Commissioner Whalen just asked one, so I'm down to two now. You spent quite a bit of time having a discussion with Mr. Young around the whole notion, I guess, of generation and transmission facilities and the basis on which you would look at an economic evaluation of those, and I think you testified in a couple of areas, and I won't refer to the testimony, or the transcript but you do say not just the estimate of the net present value over the life of the project (inaudible) some alternatives. We should look at, among other things, rate impacts and how long the adverse ... and indeed, I believe you commented on a specific example of maybe in the Yukon where indeed the utility decided to absorb some short-term costs and charge them out later on a particular project, and I guess I just heard prior to listening to the cost of service variety of experts comment on the cost of capital whereby I believe they're almost with out exception that certainly they were all of the view that Hydro should over time move to an investor-owned utility type of business certainly, based on appropriate return on investment and return on equity, and that sort of thing. I see ... and you would think in terms of an investor-owned utility with a view to looking at sort of the economic analysis and the payback, if one were to look at it on that basis, I would think the shareholder in certainly a private company in any event, an investor-owned business would want that return as quickly as possible based on what the market would bear. How do you, from where I understand you're coming from here, how do you reconcile those two perspectives?

MR. OSLER: With care. The tendency from an investor-owned utility perspective would not be to undertake certain types of investments for the reasons you and I are talking about it. They wouldn't just look to an analysis of net present value. They'd look to making sure they got it back soon enough, and they wouldn't want to get into a big fight with a whole bunch of ratepayers in order to do some noble social purpose, okay? Particularly with, it would take a long time to get their money back ...

MR. NOSEWORTHY, CHAIRMAN: Uh hum.

MR. OSLER: So some would argue, therefore, that a utility such as Newfoundland Hydro or Yukon Energy Corporation, which are Crown-owned, whether they are investor-based, whether it be run by investor-based rules or not, have to find a way to meet their broader social purposes, while at the same time still, for rate purposes, being run like an investor-owned utility, and Yukon energy has 60 percent debt, 40 percent equity. It was set up that way. It didn't have to build it up through the backs of the ratepayers, it was set up at the initial time period that way. It is the direction of the utility board, is to give it a normal commercial type of rate of return less a half a point or something, so it has all the rules that somebody would like to get to here, and for those types of reasons it found itself looking at the world not dissimilarly from what an investor-owned utility would do for a while, and it got into some heat as to when are you going to do some of these other things. We've had no development of new facilities under this new ownership, even though we've had for ten years. What's wrong? And one of the ways of grappling, kind of grappling with those two things was what we call the flexible term financing type of instrument where the owner of the utility, which was the Yukon Development Corporation and could arrange to finance some of the debt for those transmission lines in such a way that it could hold out that the utility's ratepayers would be no worse off at any one time period, and it would recover the balances later down the road, and it had to convince itself that that was a reasonable investment and it was meeting its broader social objectives while maintaining the rate base approach to regulation and doing things that no private utility would normally do, and its board of directors and people had to be convinced this wasn't a stupid idea, it was a good prudent investment doing what their mandate was to do. It took a while, and we'll see ten years from now whether it's ...

MR. NOSEWORTHY, CHAIRMAN: Certainly they were foregoing up front an element of revenue that, that no, I guess, private investor utility would generally speaking be prepared to ...

MR. OSLER: Well the Whitehorse No. 4, that I was talking about with Mr. Kennedy, had the (inaudible) reputation of being built at exactly the wrong moment. They put the shovel in the ground at the time the mine shut down, and my first experience in the Yukon was to testify before the National Energy Board on this facility among other things, and it's the only case in my life where I've seen an asset that had absolutely no value for $60 million out of a rate base of say, $100 million, because the load wasn't there for which it was built, and so the concept of a flexible term, the National Energy Board took some advice and said well we think this should be put off the balance sheet for the time being for rate making purposes, and now when Yukon bought all the facilities and assets of the Northern Canada Power Commission, it negotiated with Canada *(phonetic)*, what we call a flexible term debt, which you probably wouldn't see in very many places, but it effectively said we're only going to pay the interest on that portion of the purchase, thank you very much, when the facility is being used, because you built it, you continue to bear the risk.

MR. NOSEWORTHY, CHAIRMAN: You said you wouldn't see it in very many other places, but would you see it in any?

MR. OSLER: I don't think you'd normally see it at all, and I think you'd ... but it's ... when you try to balance government objectives in the long run, and short-term rate making, there are techniques that I think you can use that can keep everybody wearing their hat properly, the board of directors of the utility, the board of directors of the owner, and the utility board, and I think we're learning a few things over the years as to how to do that, and that's all I'm really getting at, and it takes a bit of creativity, and that didn't happen overnight.

MR. NOSEWORTHY, CHAIRMAN: Uh hum. Okay, thank you. The second question, and I won't be long, and I realize it's a little bit after lunch and I'll just conclude. It relates actually to the whole sort of cost benefit economic analysis, and we saw a capital budget which I think is $26 million this year from Hydro with, for the most part I think it's fair to say, a very limited cost benefit analysis in respect of the projects, and I believe there was a couple, and this came up earlier with Hydro witnesses, and there's a variety of, if we could ... in the application, Mr. O'Rielly, I think it's B-6, the capital budget application, there's ... just scroll up a little bit. Yeah, these projects are required for one or more of the following reasons, and these would be the criteria admittedly not quantitative in certain instances that would be used by Hydro to judge a go versus no go on certain capital investments, and some of these capital investments would be fairly small, I guess, anything below $50,000 is not really reported other than in a collective sense, but there are projects in here, distribution projects, upgrade distribution system, central, northern Newfoundland, which would be 1.3. Provide service extensions, $981,000, $1 million, now it seems to me on a cumulative basis year after year, certainly that would have a significant impact in looking at, in looking at comparable to a transmission or generation to a degree, especially small scale, significant impact as far as looking at the cost benefit aspects are concerned. Would you have any observation to make? Is the type of approach, and you are familiar with utilities elsewhere, is the type of approach employed here by Hydro generally speaking the practice, if you will, in relation to other utilities as it relates to limited cost benefit analysis in this, with regard to these projects?

MR. OSLER: Let me say I have not reviewed the capital budget or the methods of the cost benefit assessment so I can't give you an overall report, but I think the language that you're showing me here is not uncommon. I have seen the justification for capital projects often involving non-quantifiable items, safety, human life, etcetera, and to try and review that externally is difficult because they are presumably based on things that we have to do and it's hard to translate them into a type of language that an outside reviewer could understand, unless you're a technician saying, yeah, I agree with you, you've got to replace that piece of equipment, it's faulty or it's unsafe, or it's unreliable. Cost benefit assessment is a lot more straightforward, if you like, if you're trying to meet projected customer loads and what alternative methods of doing generation is something that we can all understand, we've got some options here. We don't have one compelling approach. That's more the issue of assessing A versus B, and I think in general there is concern from utility boards, whether I'm working for the utility or the intervenors, as to the extent to which full justification is given for some fairly major projects from all the points of view that seem to be relevant. There have been some prudency decisions, I guess, in Yukon where certain costs have a lot of expenditures on investigations were disallowed and not put into rate base because the Board didn't think after review that they were justifiable costs. I think when we're doing cost benefit from a ... if I can just close it on a very broad level, there is cost benefit assessment as to whether you should "go" or "no go". There's a cost benefit assessment as to whether you should take this alternative or that one, and there's also, in my history of cost benefit, you also look at distributional effects, and I'm talking now not just for utilities but elsewhere. I mean it's been accepted for almost my entire career that you don't just look at the aggregate net benefit, you look at the distribution effects or you might get in trouble, and I think a lot of my comments about rate impacts refer to in this bailiwick, that type of issue. You've got to look at who is going to get hurt and who is going to get helped and how the benefits are distributed or you'll be in trouble. It's just a practical comment, and that is not typically addressed easily. There's capital planners just looking at whether the darned costs make sense or not, and that's the rate department or some other group, and they haven't traditionally, haven't always had to go forward and justify it, so if you go through a transition from not having to justify in a public forum, particularly the forum where your rates are set, to having to do that, you will go through a transition and you'll have to figure out what level of detail you want to get in. Right now Manitoba Hydro is having an interesting debate with its regulator on, and the government on this matter because it purchased Sentra *(phonetic)* which was subject to the same rules you're talking about. Manitoba Hydro as a utility is not subject to capital approval decisions by the Public Utilities Board. It only approves its rates.

MR. NOSEWORTHY, CHAIRMAN: That is a dilemma, it's not an easy situation either, I'm sure, from the utility's perspective or ours, but I was just inquiring as to basically what you know from your experience.

MR. OSLER: What level of expenditure ... I mean boards of directors worry about this, what level of expenditure should we be making on capital to keep the system whole. It's not one that there are easy guidelines on, and they do have ... as you increase your rate of return requirement on your rate base, the implications of spending will become bigger in terms of rates.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Osler, that's all I have. Questions on matters arising, are there substantive questions? We could indeed conclude possibly, I don't know.

MS. BUTLER, Q.C.: Mr. Chairman, in fairness, I'd like to have a discussion with my colleagues in relation to pursuing questions?

MR. NOSEWORTHY, CHAIRMAN: That's fine. We'll ... would anybody have any objection, we're running a little bit late, to reconvening at 2:00 or is there somebody who requires some more time over lunch? Okay, if not, we'll reconvene at 2:00, thank you very much.

(break)

(2:00 p.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you and good afternoon. Before we get started, Mr. Kennedy, are there any preliminary matters?

MR. KENNEDY: Yes, Chair, I believe has a preliminary matter to report on.

MR. NOSEWORTHY, CHAIRMAN: Mr. Young, good afternoon.

MR. YOUNG: I'm pleased to say we're winding down on our undertakings and we're running out of witnesses, so there's not many of these left. There were a couple that came up the other day though and I've distributed them. The first one that I'd like to refer to, the document which is called "Government Agencies and Departments, Interconnected System", and it answers questions that arose from examination, I believe, by Mr. Saunders. It relates to the preferential rates in the (inaudible) system. The other document is the rural customer power service disconnection for nonpayment of account, and I'm not sure what the numbers are up to.

MR. KENNEDY: U-Hydro No. 32.

MR. ALTEEN: Which one is 32.

MR. YOUNG: That would be the first one, Government Agencies and Departments.

MR. KENNEDY: The Government Agencies and Departments.

MS. HENLEY ANDREWS, Q.C.: It was what number?

MR. KENNEDY: U-Hydro No. 32.

<u>EXHIBIT U-HYDRO NO. 32 ENTERED</u>

MR. YOUNG: So the disconnect payment, the service disconnection for nonpayment of account document would be 33?

MR. KENNEDY: That's correct.

<u>EXHIBIT U-HYDRO NO. 33 ENTERED</u>

MR. YOUNG: Those are all the preliminary matters, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Young. We'll move now to questions on matters arising and I'll ask Ms. Butler and Newfoundland Power.

MR. YOUNG: We don't have any, no, that's fine.

MR. NOSEWORTHY, CHAIRMAN: I apologize, we'll get this sorted out one of these days. Ms. Butler, do you have any?

MS. BUTLER, Q.C.: Thank you, Mr. Chairman, we have nothing arising either.

MR. NOSEWORTHY, CHAIRMAN: Thank you very much. Mr. Browne?

MR. BROWNE, Q.C.: No questions.

MR. NOSEWORTHY, CHAIRMAN: Counsel, do you have any questions?

MR. KENNEDY: I just have one question, Chair, and it arises from a question by Commissioner Whalen, Mr. Osler, and specifically in response to some questions you were asked concerning the RSP and the alternatives employed. The terms that's often used in this field is the term "intergenerational", and I guess, again, from the layperson's perspective, when you're talking about generations, you would be, it's sort of loosely defined as periods of at least 20 or 25 years in length, and a full generation of individuals, and I'm wondering, for the purposes of the RSP sometimes the word "intergenerational" is raised as an issue of concern with the RSP, and I'm wondering if you could just give me your view on what period of time you would consider to be problematic in spraying out the collection of deferred costs as the RSP does, keeping all that in mind?

MR. OSLER: Okay, the term "intergenerational", which I've tried to avoid using in an electricity hearing, I don't think is usually as literally taken in rate hearings as the definition you gave, and I think people have quite frequently used that term for concern about passing costs from one time period to another time period in a material way such that you're asking future customers, or people who happen to be on the system in the future, or their loads that happen to be on the system in the future to pick up costs that arose today. In that context, I think I would agree with Mr. Brickhill that when looking at fuel adjustment riders, six months to a year is a good long time period before you start to act on them and address them in the manner I talked about. It would be another issue entirely when you start delaying it a long time period beyond that. In the case of water accounts, I think there is a view behind the creation of such hydraulic stabilization accounts, that we are really looking, if you want, at a very long run, that it's not the fault of the people today that the water was low or the water was high, and that we are trying to see something that could balance out in a very long-run sense, whatever the long-run time period is for the average, and I think in that context, my experience is we are not typically worried about the timing issues at all. I have never come across in my experience a case where we have a load account stabilizing and that raises another whole set of issues, so I don't have a sense of timing, but if I did I suppose it would be closer to that for fuel than it would be for water by a very considerable degree. I think if we try ... if costs start to shift from today to a future, my experience is five years is a fairly long time period when people start talking about amortizing certain amounts that were incurred and we're going to try to write them off over a reasonable time period. They'd really have to have a long-term benefit to be justified to write off over a much longer time period and typically a bunch of costs that were incurred for fuel last year don't have a long-term benefit, we're just trying to smooth them out. It's not like an investment.

MR. KENNEDY: Thank you, Mr. Osler, that's all the questions I have, Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Kennedy. I'll move now to Mr. Hutchings on re-direct please?

MR. HUTCHINGS: We have nothing further arising, thank you, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, and that would conclude Mr. Osler's testimony. Thank you very much, Mr. Osler, I appreciate it and found it very useful, thank you. We'll move on, I guess ... Ms. Butler, are you in a position to call Mr. Brockman please?

MS. BUTLER, Q.C.: Thank you, Mr. Noseworthy. Mr. Brockman, whenever you're ready.

MR. NOSEWORTHY, CHAIRMAN: Good day, Mr. Brockman. Do you swear on this Bible that the evidence to be given by you shall be the truth, the whole truth, and nothing but the truth, so help you God?

MR. BROCKMAN: I do.

MR. NOSEWORTHY, CHAIRMAN: Thank you sir, very much, please be seated. Good afternoon, and once again, welcome. May I ask, Ms. Butler, if you could proceed please?

MS. BUTLER, Q.C.: Thank you. Mr. Brockman, I wonder before we go through your resume because it's attached to your evidence, if I might ask you, you filed pre-filed testimony from August 2001, September 2001, and again in November 2001?

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: And are there any changes or corrections that you wish to make to either of your pre-filed?

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: Can you tell us where to find the page?

MR. BROCKMAN: On page 12 of my first supplemental, the title of the column where it says "Newfoundland Power Peak in Megawatts, MW", that should read KW and not MW.

MS. BUTLER, Q.C.: Can you just give Mr. O'Rielly a moment to get that on the screen. In the actual table, Mr. O'Rielly, it's at the top, thanks, so in the shaded yellow portion, it should say KW?

MR. BROCKMAN: That's correct.

MS. BUTLER, Q.C.: Mr. Brockman, with that correction, do you adopt your August, September, and November 2001 pre-filed testimony as your sworn evidence in this proceeding?

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: Mr. O'Rielly, can we go first to the index to Mr. Brockman's original testimony please? Mr. Brockman, before we go through the summary section of the original testimony, can you tell the panel please, your history and experience, education included?

MR. BROCKMAN: Yes, I have a Bachelor's Degree in Engineering, partial completion of a Master's in Engineering and Economics. I have about, a little over 25 years of experience in utility planning, rate making, consulting, and some educational and teaching experience. I plan transmission, distribution, and generation systems. I have designed rates, done cost of service, I was a regulatory ... an assistant director for regulatory staff in Florida for about five years directing rate cases and least cost planning, and safety issues, and several others, you know, regulatory policy type questions that the commission had to deal with. I have also taught courses for public utilities reports, Public Utilities Fortnightly, on rate design and cost of service as well as least cost planning, and I think my first appearance here in Newfoundland was in 1990, but I'm starting to forget how many times I've testified here on various issues.

MS. BUTLER, Q.C.: Okay, thank you. The index to your original testimony indicates the topics that you were addressing, and we can see that they were the Rate Stabilization Plan, the test year forecast including hydraulic production, and the cost of service issues including the rural rate subsidy and rate design. Can I turn first to the RSP generally and ask you if you could just summarize for the Board your principal recommendation on the plan and indicate whether either of these recommendations have changed with your supplementary pre-filed evidence?

MR. BROCKMAN: My principal recommendation was that the cap on the residential part of the RSP not be raised above $50 million. Hydro is asking for it to be raised to $100 million, of course ... without some sort of review and, I guess I suggested at various times, although I didn't fully develop the thought that there be some sort of possibly a mini-hearing and a filing before that overage would be allowed to be recovered. I recommend that Hydro be allowed to book the numbers in their accounting books so that they could be, you know, recovered if they were shown to be prudent and, you know, advisable to the Board. I don't think I've changed that recommendation in my subsequent filings.

MS. BUTLER, Q.C.: Now, Mr. Cameron Osler has most recently given oral evidence on the RSP since you've filed your second supplementary evidence. Have you had a chance to review the transcript from Friday, November 30th?

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: And are you aware of Mr. Osler's interpretation of the term "load" as it relates to the Rate Stabilization Plan?

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: And can you provide the panel with your comments on that please?

MR. BROCKMAN: In my experience, the word "load" generally includes both demand and energy. Generally when someone asks me a question or asks me to do something with load I would try to clarify that. Do they mean demand, do they mean energy, or do they mean both, and so I think to me it was quite clear as well as, you know, reading some of the letters that were put forward as well on what exactly that meant, but I won't say that it was crystal clear because there is some confusion as to some of this, but I think that it's fairly clear what's meant by load.

MS. BUTLER, Q.C.: In the second section, which is actually Section 4 in the index to your original testimony, you addressed the test year forecast, and can you summarize for the panel, please, your evidence on Hydro's hydraulic forecast which we know, excuse me, was also addressed in your first and second supplemental testimony?

MR. BROCKMAN: Yes, what I found was in my investigation of the hydraulic forecast that Hydro put forward in the test year is, first of all, I guess there was at least an implication that there was some sort of Canadian standard on this. While there may be a Canadian standard in terms of planning and what the hydraulic planners use, I certainly didn't find in my investigation that there was any sort of regulatory test year standard on what should be used for the hydraulic forecast in terms of number of years or how it should be calculated. We talked to some of the people that Hydro talked to as well as some of Hydro's own witnesses, Mr. Henderson talked about whether or not his survey that he did showed that everybody had a standard and that they used this standard in terms of test year. We just didn't find the standard, I don't believe there is a Canadian standard in my opinion. Hydro calculates their test year forecast for hydraulic generation based upon the full historical record and some of that is even historical before the plants even go into service, and I just don't think that is appropriate. I think that something better would be to use, say, the last 30 years of data, because it appears to me that the numbers do change quite a bit. There appear to be wet years or wet periods and dry periods and so on and so forth. I know that Environment Canada uses only 30 years in their climatological questioning, so as far as I can see, 30 years would be more appropriate. I also looked at several of the utilities and their responses if they used median rather than simple averages. A median calculation would give you an answer if you looked at the day where you were right half the time and wrong half the time. I think that's a better way of calculating the number than using just a simple mean, so that was my recommendation.

MS. BUTLER, Q.C.: Now, subsequent to the filing of your principal evidence on this point and, in fact, I think subsequent to the filing of your first supplementary, have we forwarded to you a copy of an exhibit referred to as U-Hydro 17.

MR. BROCKMAN: Yes, that's correct.

MS. BUTLER, Q.C.: And I wonder, Mr. O'Rielly, if we might just see that exhibit. This was provided by Hydro in response to an undertaking they had given relevant to a question by Commissioner Whalen. In reviewing this ... is that the revised one Terry?

MR. O'RIELLY: Yes, it is.

MS. BUTLER, Q.C.: Okay, in reviewing this document can you tell us please whether this document from your review addresses Commissioner Whalen's question, and what results you take from it?

MR. BROCKMAN: I guess I'll have to let Commissioner Whalen decide whether it completely addressed the question. There were no word conclusions, I guess, if you would ... that perhaps went to her question, although there was a word conclusion in the document. I think Table 4 of that document, if we could go to that, shows what I think the conclusions from it are, and if you'll look at Table 4, over in the last three columns there are calculations of the 30 year average, rolling average, which is my recommendation. Then there's one called reduced full average, which really isn't, no one is proposing that. That's Hydro's full historic average minus some years that they took out where some of the things don't exist, and then that last column is sort of Hydro's full historical average calculation, and then if you look at the ... we can only calculate the 30 year average based on this data from, I guess it's 1979 onward, and if you look at those 22 years of data beginning in 1979, you find that in some years Hydro's calculation would have been better, and in some years the 30 year rolling average would have been better, but the bottom line for me is that for 13 of those last 22 years, our method would have been on, or have been closer to the actuals than Hydro's method. For nine of the last 11 years, our method would have been better, so in the 22 years we were about 60 percent, you know, accurate, versus Hydro, and in the last 11 years we were, I think it's about 82 percent, if my calculations are correct. So that's the conclusion to me, but again, I don't know whether that answers Commissioner Whalen's questions or not.

MS. BUTLER, Q.C.: Mr. O'Rielly, can we go back now please to the index to Mr. Brockman's original testimony, and the final issue addressed back in August was the cost of service, rural rate subsidy, and rate design.

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: As it relates to the rural deficit, and the abolition or reduction of government and preferential rates, are you aware of Hydro's position on that issue?

MR. BROCKMAN: I think so, and I say I think so because after reading Mr. Hamilton's, the transcript of Mr. Hamilton on November 27th, it appeared to me anyway that Hydro is currently saying that perhaps the restrictions on them are not quite as severe as I thought they were, that the Orders in Council perhaps don't still apply to all these rates, so I think I'm aware of their current position, but I'm not a lawyer so I can't interpret all of those issues, but ...

MS. BUTLER, Q.C.: And what is your recommendation for the reduction of the subsidies, Mr. Brockman?

MR. BROCKMAN: Well, as always, I recommend that Hydro continue, or continues to do all they can to reduce those subsidies. I think I've testified several times in past proceedings that I would like to see some sort of schedule filed, some sort of definite plan to eliminate the subsidies, as much as ... well not eliminate, because I don't think we can completely eliminate them, but to reduce the subsidies as much as reasonable and possible. I would like to see Hydro, you know, actually have to file something that says here's our plan and here's what we're going to do, rather than saying we'll wait until the next rate case every time, and they have made some progress in this proceeding, by the way, on that issue, on government subsidies in some of the rural areas, but I would like to say, and I'm a little impatient, so ...

(2:15 p.m.)

MS. BUTLER, Q.C.: Okay, thank you, and can I go now, Mr. O'Rielly please, to the index to Mr. Brockman's first supplemental filed in September? Now as we can see here, Mr. Brockman, you readdress the issue of the hydraulic generation forecast.

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: Which we've addressed already now this afternoon, and then you gave comments on Mr. Bowman's evidence on behalf of the Consumer Advocate, and Dr. Wilson on behalf of the Board. Looking at Dr., your comments on Dr. Bowman's evidence, this concerned the demand energy rate?

MR. BROCKMAN: Yes.

MS. BUTLER, Q.C.: And in that sense, so did Dr. Wilson's, so could you just summarize for the Board please, your position on the demand energy rate currently in place between Hydro and Newfoundland Power?

MR. BROCKMAN: Yes, as is on the record, I testified before, at least once or twice before this Board that all other things being equal, a good regulatory procedure would be to have demand energy rates on customers who can afford the meters. I think Mr. Osler just repeated that statement himself just a few hours ago, or an hour or so ago. I guess the problem with that is in the all other things being equal. Normally we do that as a matter of course, but once we recommended that that proceed and the Board went forward with that particular recommendation, I think I recommended it, and I think Mr. Paul Hamilton recommended it, and perhaps several others, we found that it would create a lot of volatility in Newfoundland Power's revenues, and their financial people, and their accounting people didn't particularly like that volatility, so all things considered, we decided that perhaps it wasn't as great an idea as it seemed like at first. It did have some advantages and that it perhaps better would signal the costs in the short run, and I say the short run because Newfoundland Power does pay their costs, their demand costs and their energy costs are reflected in the cost of service study and get flowed through each time we have a cost of service study, and any time we have a rate hearing, they get all their costs. It's just whether or not they have a separate demand energy charge. The other thing was is the time that we were particularly concerned about this, Newfoundland Power was particularly concerned because people were really more concerned at that time about reducing demand. Demand side management was probably a bigger issue than it is today, although it's still an important issue. Newfoundland Power simply hasn't had a lot of demand growth in the last ten years. In fact, I think in one of the tables in my evidence shows is their demand has, in fact, fallen, so it's not as important of an issue, I don't think, as it was at the time we first pushed for it, and because there are some negatives at least from the financial perspective, of the financial planners at Newfoundland Power, we're no longer recommending it as necessarily an option to pursue. One other point on that is that I think it's also important to remember that to some degree rate making is sort of like squeezing a balloon. You have a set revenue requirement in these cases, and you can charge customer charges, you can charge energy charges, you can charge demand charges, but if you reduce one, the other two have to go up, and vice versa, so if you squeeze the balloon in one place, it may pop out somewhere else. Newfoundland Power currently has energy growth, but they don't have demand growth, so if we do something that will reduce ... if we put demand charges in and then reduce the energy charges, we may have a different problem. We may create the need for base load plant, for instance, on the system. So you have to, we have to carefully design the rates to make sure that you can still keep your tail blocks where you need them, and you don't overly encourage energy growth when you put in demand charges. Sorry.

MS. BUTLER, Q.C.: No, that's fine. And the final point you make in the first supplemental evidence, Mr. Brockman is in relation to Dr. Wilson's evidence, not only on the demand energy rate, but also on his position which supports the abolishment of the RSP, and can you tell us your recommendation to the Board, or position to the Board, on that point?

MR. BROCKMAN: Well, I don't think that the RSP should be completely abolished. I think that the customers like having the, some of the stability that the RSP gives them. I think that, as well, Hydro probably enjoys the stability on revenues that the RSP gives them, so I don't think it should be completely abolished. However, I would like to see more incentive put on Hydro to control fuel costs and be more efficient with their hydraulic generation as well as their thermal generation. I'm not saying they're inefficient, but there's sort of an economic perspective of can we give them more incentive than we have now, so that the Board doesn't have to look as hard all the time and maybe Hydro goes on their own and tries to become efficient. They do that now but it's just an economic idea that we like to give utilities as much incentive as we can. So for that reason I wouldn't abolish it, but as I said, I would not set the cap to $100 million, and I said $50 in my evidence, but I think this is something that probably would be discussed as this proceeding goes on. I mean $50 million is not a magic number, but it certainly, you know, we can talk more about that later, but you know, I don't want to see it go too high. I don't want Hydro to hit $100 million because I don't think it gives them any incentive in that respect.

MS. BUTLER, Q.C.: So the practical effect of capping the retail RSP at $50 million would be what?

MR. BROCKMAN: Well, the practical effect would be that if Hydro's fuel costs went over $50 million are there extra costs ... it wouldn't just have to be fuel costs, it's fuel costs, you know, created by hydraulic production as well as load, changes in load, but it's mostly thermal production costs. If they went over $50 million, as I said, I think Hydro should be allowed to book the overage and then come to the Board for a short limited proceeding which would really be just on the, why is the fuel cost, you know, more than we thought it was going to be, why is the hydraulic production less than we thought it was going to be, or why has the load changed, and it would be limited to those fairly limited issues, and it would probably be a one or two, a three day hearing, perhaps, and it's not unlike the hearings that the utilities that I'm familiar with, regulated in Florida had on fuel adjustment. We brought them in for a one or two day hearing every year, or every six months, depending on what timeframe you're talking about, and we looked at their cost and it gives everyone a chance to sort of see what's happening. It doesn't allow us to get into the situation that we're in now where we have fuel costs based on $12.50 a barrel of oil, because we haven't reviewed, you know, in that context for a long, long time, so I think it would create that sort of an incentive to have the Board get a regular review of this important cost of Hydro. The details again of that I think would have to be worked out.

MS. BUTLER, Q.C.: Okay, thank you, and Mr. O'Rielly, can we go finally now to the annex to Mr. Brockman's second supplemental filed in November? Thank you, and again, you would readdress the hydraulic generation forecast which you've already told us about. The third item on your index here relates to relative allocation proposed rate increases. This is in response to Mr. Osler's position on the relative rate increases between Newfoundland Power and the industrial customers?

MR. BROCKMAN: Correct.

MS. BUTLER, Q.C.: And can you give us your conclusion please?

MR. BROCKMAN: Yes, I looked at Mr. Osler's issue and, you know, I thought it was an interesting question, one which deserved an answer, and so I did go back and look at what has happened to the rates of both Newfoundland Power and the industrials since 1992, because I think he did have a good point. There should have been some increasing spread between the industrials and Newfoundland Power, and in fact, what I found was the industrials had had three rate decreases during that time and Newfoundland Power had had an increase, and so that in the bottom line, as I present in my supplemental, my second supplemental evidence, is that the spread has widened to about 16.2 percent between the ICs and Newfoundland Power since 1992. Now the other issue that came up was that some of these increases are created by fuel. The price of energy is going up because fuel is going up, and insofar as the industrials use more energy relative to their demand than Newfoundland Power does, which they do, you would also expect there'd be more of an increase from that effect on them, so I found that, you know, I was satisfied that the indication was that we were moving in the right direction. Mr. Osler didn't really provide us with any, at least not that I could find, any great amount of detail that, you know, this is wrong or that's wrong, to give us much to work with in terms of, okay, what should we do with this issue other than to try and answer it as I have here.

MS. BUTLER, Q.C.: And finally, the issue that's number four on the table of contents, the allocation of generation costs, this addresses the allocation of generation demand costs based on coincident peak?

MR. BROCKMAN: Correct.

MS. BUTLER, Q.C.: And what are your conclusions on that point, Mr. Brockman?

MR. BROCKMAN: Well, as I've said, I support a multiple CP for the allocation of demand costs for generation demand on the system, and the reason I support that is because, my understanding from the evidence is that Hydro currently uses essentially two generation planning criteria. One is a farmed energy criteria so that they have to make sure that in the dry years they have enough energy from their thermal plants as well as all their plants to make sure that the lights don't go out, and that's a common planning criteria used by hydraulic utilities. The other criteria that they use is something called a loss of load criteria, LOLH, you'll see it in the evidence, and the LOLH is calculated for every year, every hour of the year and the numbers that are in the filings of Hydro show that for the peak month that they chose, which was January, about 60 percent, I believe, of those hours ... about 60 percent of the total yearly LOLH was contributed in January, and I think another 23 percent was contributed in February and then March and December pretty much contributed the rest, so that clearly at least two of those months are, seem to be very important. I mean one is clearly more important than the other, but only 60 percent. The other issue that I find with that is that there is always a chance, and if we look at recent history, we find that the peaks have occurred in March, they have occurred in December. They don't always occur in January or February, so I think for all those reasons, I don't support a 1-CP, I certainly would ... I prefer a 4-CP, but I think a 2-CP is better than one, so that's my position.

MS. BUTLER, Q.C.: Okay, thank you, Mr. Brockman, those are my questions, Mr. Chairman.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Ms. Butler. Thank you, Mr. Brockman. We'll move now to Hydro please, Mr. Young, for your cross?

MR. YOUNG: Thank you, Chair. Good afternoon, Mr. Brockman. It's always a pleasure.

MR. BROCKMAN: Good afternoon.

(2:30 p.m.)

MR. YOUNG: Mr. Brockman, I didn't hear that you discussed in either your recapping of your pre-filed testimony, and I didn't see it in your pre-filed testimony, any discussion about common and specifically assigned plant allocations, and it's an issue that's been in this hearing, and it's one that I think we've discussed before. I'm just wondering if, generally speaking, before we get into this in some detail, I notice on page 22 you indicated that there was some sound reasons, and I don't think you need to refer to it.

MR. BROCKMAN: Okay.

MR. YOUNG: To keep to the regulatory principles that were decided following the 1993 generic cost of service hearing. Is that still your position here?

MR. BROCKMAN: I'm sorry, would you repeat the question?

MR. YOUNG: Yeah, I'm just wondering, I mean you ... it's just sort of a lead-in to the issue, that you had mentioned that on page 22 of your testimony that the 1993 report of the Board following the generic cost of hearing, generic cost of service hearing, sorry, you indicated, as I understand it, that you prefer not to throw the baby out with the bath water and move on from there, is that correct?

MR. BROCKMAN: Yes, I can't remember how many weeks we spent on that generic proceeding, but you know, there were some hard fought battles. I think the Board made a wise compromise between all the issues, and so the tack that I took with respect to most of these issues was rather than trying to sort of repeat my old, where I lie on some of these things, you know, what were my leanings on them, was to go with what the Board said. I think the Board did make a wise compromise in that order, and so insofar as Hydro has followed the Board order, and I did check, you know, the issues to see whether they had in fact complied with the Board's order, and I think for the most part they did. There were several other issues that came up later, I guess, that some of the other witnesses have raised, where I didn't take great issue with them, I haven't talked a lot about them, and while I think in general you have followed that order, and that's appropriate. Did I answer your question?

MR. YOUNG: Yeah, I think you did, yeah. Mr. O'Rielly, I wonder if you could bring us to page 15 of Mr. Budgell's pre-filed evidence please. Thank you, can we se lines 24 to 29 on that page, on the bottom. This relates to, as you can see here, and I have no doubt you've read it, a change that's occurred since then, a rural inquiry, and you have some knowledge of that also. Perhaps I'll just read the part that's been contentious here, and it says at that time the Board recommended both generation assets and the 138 kV transmission line on the Great Northern Peninsula, be assigned on a provisional basis being of common benefits to all interconnected customers, and that's a subtransmission cost for lines whose voltage is below 138 kV be specifically assigned. You've got it so we can see the rest of this, great, Mr. O'Rielly. The Board further recommends re-examination of these cost assignment decisions and rules for cost assignment at a future hearing.

MR. BROCKMAN: That's correct.

MR. YOUNG: Have you been reading the transcripts in relation, and I'm trying to see how much time we can save here, as to the issues that have come up on this matter, about the GNP?

MR. BROCKMAN: I have been reading the transcripts and trying of all the issues, I will admit I haven't done a great study of it, but I have been following along.

MR. YOUNG: The point that Mr. Budgell is making further in his evidence, which I'll ask you to comment on, is that now that the GNP is connected that his position, Hydro's position in fact, is that the generation which is now interconnected should all be assigned to common, do you agree with that position?

MR. BROCKMAN: Well, I agree with the position. I agree with the position, I agree with the Board's position, let me put it that way, in the '93 cost of service hearing, which said that where a line or a generator was shown to be of substantial benefit to the rest of the ratepayers, it should be classified as common, and I think that's what Mr. Budgell was currently trying to say, trying to follow the issue with what he says, he says that in dry years, for instance, the generation could be of benefit to the rest of the island, and he makes a couple of other comments as to times when it could be used, so I have no reason to doubt, you know, he knows the system and he's, you know, familiar with what's going on and I'd have no reason to doubt that that's true, so I don't take issue with that. I think I'm agreeing with it.

MR. YOUNG: Okay, the bottom of page 16, could you just scroll down a bit further, Mr. O'Rielly, please? We find at the bottom of this page under the heading of common plant there, thank you, that Mr. Budgell has set out the principles as to the assignment of plant as either common or specifically assigned, and at this point he's talking about in (b) and in (d) there about transmission plant in particular. I wonder if you could just scroll down to (d) please, Mr. O'Rielly? Thank you. Perhaps, Mr. Brockman, it might be easiest if you could just read that in starting with line five, and I'll ask you to comment about it after.

MR. BROCKMAN: It says, all of Hydro's transmission and terminal station plant that connects a single customer and remote generation or voltage support equipment that is of substantial benefit to all customers on the grid, for the purposes of this guideline under any normal operating scenario, the output of remote generation can be levered *(phonetic)* to the 230 grid, that is in excess of radial load and then the remote generation is considered to be of substantial benefit to all customers and as such the transmission and terminal plant, terminals plant connecting it to the grid would be assigned common.

MR. YOUNG: Do you have any comment about that?

MR. BROCKMAN: No, I think I agree with it.

MR. YOUNG: There has been another assignment change which doesn't relate to the GNP directly, but it's to the Doyle's-Port Aux Basques system, and Mr. Budgell speaks about that also. The transmission and terminal plant was previously assigned to Newfoundland Power and it's now assigned common, do you agree with that change also, (inaudible) it's the same principle, I believe.

MR. BROCKMAN: I'm sorry, I'm not following your question.

MR. YOUNG: Okay, this relates to the line going to Port aux Basques, in that area.

MR. BROCKMAN: Uh hum.

MR. YOUNG: Do you understand that the same principle was applied there as was applied for the GNP, or ..

MR. BROCKMAN: Yes.

MR. YOUNG: Okay.

MR. BROCKMAN: And I agree with the principle, no matter where it is applied.

MR. YOUNG: And this test, is this test one that would be used elsewhere, or one similar to one that would be used elsewhere for interconnecting systems?

MR. BROCKMAN: Do you mean in other jurisdictions?

MR. YOUNG: Other jurisdictions that you're familiar with, yes.

MR. BROCKMAN: Yes, I believe it's an appropriate one that would be used elsewhere.

MR. YOUNG: Still with assignment to plant, but looking at a different beast, have you been familiar with the issue of the frequency converters at Corner Brook and Grand Falls?

MR. BROCKMAN: I'm familiar with the issue. I don't think I took a position on it.

MR. YOUNG: I don't think you did either, and I'm going to ask you do that I suppose, and see where you stand on it. You may be aware, and tell me if you're not, that your client, Newfoundland Power, once had a customer in the vicinity of Corner Brook, were you aware of that, who received power at 60 hertz?

MR. BROCKMAN: No.

MR. YOUNG: You weren't aware of that, okay. I think the evidence is that, and which I'll ask you to respond to, and if you're not familiar with the facts here, of course, you can respond to this as if it were a hypothetical, but the evidence is that there were no other customers served at 50 hertz left in Newfoundland except for the two paper mills which have frequency converters, they in a sense serve themselves at 50 and themselves at 60 through the frequency converters, were you aware of that generally?

MR. BROCKMAN: Yes.

MR. YOUNG: What is your position on the proper assignment of those frequency converters?

MR. BROCKMAN: I think what we're talking about there perhaps is, are facilities whose sort of essential character has changed over the years. The reason they were put in may be different than the reason they are currently being used, and I think when that happens oftentimes we have to make some adjustments. In fact, I think that was the Board's reasoning in the cost of service, in the '93 order, where they talked about using things like load factor to classify plant, and they said things change, you know, over time, and so I think the Board is cognizant that we can't just say this was built for this reason and forever and ever just forget about it. Usually we can but where the essential character changes, so that I think if you have a situation, and again, I haven't studied that issue in great detail, but, you know, I don't know all of the history of that whole area but if, in fact, only the industrials are benefitting, or these two industrial customers are benefiting from those frequency converters, and they're the ones who really need them and benefit from them, then it seems to me fair for them to pay for the, and so probably they would be classified as specifically assigned.

MR. YOUNG: Can I ask you if that would be consistent with the way regulators treat these kinds of issues in other jurisdictions in your experience?

MR. BROCKMAN: Yes, I think it is, but different regulators do different things. I mean oftentimes in a situation like this we don't necessarily want to have to examine every single piece of equipment on the system in great detail, so sometimes regulators just make up rules, like is it 230 kV or above, or something, and if it is let's classify it as common. I mean but in general I think that's consistent with good regulatory principles.

MR. YOUNG: I wonder if I can turn now to the RSP issue.

MR. BROCKMAN: Okay.

MR. YOUNG: And could I direct you to page 11 of your pre-filed testimony please, at the bottom of the page, or near the bottom, at line 23. I wonder if I could ask you to read in, starting at line 23, that sentence there, please.

MR. BROCKMAN: In the circumstances of this proceeding, Hydro's proposal to incorporate a $20.00 per barrel fuel cost in base rates is a reasonable enough balance of the need to improve fuel cost recovery and provide rate stability.

MR. YOUNG: Now, I take it from that obviously that the $20.00 a barrel base rate is not a problem. I'm wondering if you could respond to this point. The RSP, I think, and it's been said enough times here in this hearing that we're getting almost bored to hear it, but it's intended to protect Hydro from the matters that are outside its control ... fuel prices, variations in load, and variations in hydrology, is that your understanding?

MR. BROCKMAN: With the possible exception, and it's relatively minor, but not completely minor, that not all those things are outside of Hydro's control. I'll give you an example, I mean fuel costs, certainly Hydro doesn't control the price of fuel oil in the world, but they do control what they purchase, and they do control how they operate their hydraulic generation so with that possible caveat, yes.

MR. YOUNG: Yeah, I mean Hydro can react to some of those things, and I suppose over a longer period of time, Hydro ... it could shape the load, but within any sort of short period of time, essentially it gets what it sees from its customers, is that correct?

MR. BROCKMAN: That's correct in terms of the load.

(2:45 p.m.)

MR. YOUNG: You reiterated today your point about the $50 million cap, and you talked about the possibility of having a short proceeding to deal with that. Hydro's testimony on the matter is to the effect that the fuel price forecast of $28.00 per barrel, all things being equal, and if that turns out to be reasonably accurate, the balance is going to be exceeded.

MR. BROCKMAN: That's correct.

MR. YOUNG: Pretty soon, isn't that correct?

MR. BROCKMAN: That's correct.

MR. YOUNG: And in fact we can see some of this, even though this is for 2003 and 2004, the numbers on the screen from page 11 suggest that that's the case. I'm wondering why you think it's something to be deferred and to be looked at at that point and don't you think this is the hearing now when we should consider this issue about going over the $50 million cap?

MR. BROCKMAN: Well, yes and no. I think it's probably now perhaps is the time to look at this year, or the test year, but I think the Board also has the opportunity to set up a procedure for looking at this in the future, and if you look at the numbers on the screen you'll see that in 2003 there's 62 and then there's 37, and I guess that's based on the $28.00 barrel for oil which we're nowhere near today, but I think the Board has the opportunity to set up a procedure whereby this thing can go out into the future and be a way that the Board can exercise its regulatory review of Hydro, perhaps on a yearly basis if the costs get out of control and the cost of oil gets out of whack in the RSP, so I'm not saying that Hydro, if they do hit the 62, let's say that 62 is for 2002 ... I don't know what the number is for 2002 in the test year anymore, there's been so many changes, including the cost of oil and how Hydro is ... you know, the hydraulic generation is actually coming on. But I don't see any problem with having them in a hearing even in next year to see where things are, to see if we need to reset this thing and see if we need to rethink this thing. We're not talking about a big hearing, we're only talking about a limited scope hearing to see whether or not we should want to pass these things along, do we want to amortize them all over three years, do we want to perhaps take the amount over 50 and apply that to only one year, or just write it off in a month, or what have you. I don't see that that's necessarily a problem. In fact, I think it's an opportunity.

MR. YOUNG: Are there not enough pieces of information available now to the Board to make its determinations as to what it can do on that point?

MR. BROCKMAN: Well, these things are certainly filed with the Board. It's my understanding, I guess the RSP balances are filed every month with the Board, but there doesn't seem to be a hearing on it and no one seems to call it, object to it, or make very many questions about it, and maybe no one has questions about it, but somehow or some way we got to $12.50 a barrel of oil in the RSP over this period of time, so that tells me there hasn't really been a lot of necessarily public review if you will, I mean these are certainly public documents, I'm not trying to say that any of this has been done under the table or anything, but there is a big difference between people knowing that there's going to be a hearing, knowing that they're going to have to talk about these issues, knowing they're going to have to justify these things, and just having it sort of become automatic almost by default, and I'm not a lawyer so I don't know ... I'm sure the Board probably has a legal authority now to pull Hydro in every year if they want to ask them about these things, but it's not expected, I don't think.

MR. YOUNG: You mentioned at one point, and I don't know if you need to go to the reference, perhaps you can just respond to my question, but I believe you mentioned at one point that given Hydro's history as being away from the Board for a period of time that it may be some reason to bring it back sooner rather than later. Is that something you feel is true in this connection also?

MR. BROCKMAN: It's something ...

MR. YOUNG: Is that an issue or an element that caused you concern in relation to not having a hearing next year on the RSP in particular?

MR. BROCKMAN: Yes, it is with respect to the issues in the RSP. I don't necessarily want to have a hearing every year on Hydro's cost of capital, or their labour costs, or any of that. I'm really only talking about fuel costs, hydraulic production, you know, the things that are in the RSP, a limited scope hearing.

MR. YOUNG: The evidence of Mr. Wells, which you're probably familiar with, indicates that Hydro will be, and I know you're familiar with this fact, will be commissioning Granite Canal in 2003.

MR. BROCKMAN: That's correct.

MR. YOUNG: And you may also know that Hydro has negotiated contracts for two non-utility generating sources. These things are going to have an impact on Hydro's circumstances, would you suspect that to be the case?

MR. BROCKMAN: I think it will be.

MR. YOUNG: So I mean given the fact that the last ten years has been relatively stable as to the developments of this sort, and that in the near future, if I can call it that, is less so, do you think that we really have the kind of concern that you've stated about the longer periods of time before the next hearing ... and my suggestion to you is that Hydro's position is that we're going to be before the Board again within a couple of years at any rate.

MR. BROCKMAN: Well, again, I think there is value in the Board establishing a certain regulatory framework, a certain procedure that's a regular procedure, rather than sort of, well maybe we come in, maybe we don't. I mean these are not things, these are things that are done in other jurisdictions, fuel adjustment reviews, for instance, are done periodically, every year, every six months, and that's all we're really suggesting here. I know that Hydro has these things coming online, and that they say they're coming back in 2002. I'm not sure whether they'll be back in 2002 or not. I mean things change sometimes, and so I don't think that necessarily because of that I would withdraw my recommendation that I'd like to see some sort of regular review of what's currently an automatic (inaudible).

MR. YOUNG: I wonder if I could turn our attention now to the issue of coincident peak allocators, and you've brought that out again in your summation today of your testimony that's been pre-filed. The issue that we've discussed a fair bit up to date in relation to this is cost causality, and I'll ask you to respond to this ... there was one witness, and I can't remember which one said it, that the issue is who is taking large amounts of load at the time that the system peaks, and that's the issue, is it not?

MR. BROCKMAN: Well, no, it's two issues. There are really two issues involved in cost of service. We always sort of blend this marginal with the embedded, in the embedded sense that is true. We sort of look backward and say, you know, who was on the system today, or who was on the system yesterday. In the marginal sense we also look forward and we talked a little about that, I guess, with respect to the frequency converters, and we try to sort of blend those two issues, so when the Board makes decisions about how to design rates and how to do cost of service, and so on, they're always looking towards, not only backwards but forwards as well, and it's a balance.

MR. YOUNG: I'm wondering what looking forward does as to the choice of 1-CP, 2-CP, 4-CP, how does that change the approach the Board takes?

MR. BROCKMAN: Well, I think, as I said, that we have to look at what's causing Hydro to add generators to the system and as I testified, they seem to have two criteria. Number one is this firm energy criteria which would mean that each class's energy contribution, which could probably be said to have caused that percentage of that, you know, addition. And the other one is the loss of load hours, and you could say that each class's contribution for loss of load hours was responsible for adding generation to meet that criteria. And ...

MR. YOUNG: This is the generation demand allocator we're talking about, is it?

MR. BROCKMAN: Yes, the generator demand allocator.

MR. YOUNG: I'm wondering if that's really an important issue, the one you just raised, in relation to this issue, I mean the fact that you bill for ... I mean generally speaking, unless you're billing strictly at peak, you're going to get a fair bit of energy, and you would expect to with any kind of a base load plan, correct? You may build it for demand, your energy ...

MR. BROCKMAN: Well, you build it for both.

MR. YOUNG: You build it for both, and that's my point. You could get both, but if you're looking at allocating the system based on demand related costs, this is the thing you look to is the 1-CP, 2-CP, 4-CP, and that's on the generation side.

MR. BROCKMAN: Well, using the 1-CP, 2-CP, you know, whatever, multiple CP's ...

MR. YOUNG: Yes.

MR. BROCKMAN: As a, I think in Hydro's case now because you're doing it as a loss of load hours criteria to do your planning, we're using it as a proxy for causality. We're saying what causes these generators to be built and therefore who should pay for them, and according to your witnesses, you're building them for those two reasons I mentioned ... one, loss of load hours, and one, firm energy, and we're only trying to pick a proxy of 1-CP, 2-CP, 3-CP, as a way to sort of reflect that LOLH, and I think the 4 does it better than the 1.

MR. YOUNG: I wonder if I could refer you, Mr. O'Rielly please, to **NP-157**. Can we see the tables there, attached there please, and there's been enough said about this table, I'm not going to go into it further, just for the visual impact, but I wonder if you can point to any years in which there were four months with relatively equal system peaks?

MR. BROCKMAN: All four months?

MR. YOUNG: Yeah.

MR. BROCKMAN: I don't see any.

MR. YOUNG: No, the ...

MR. BROCKMAN: Well, no, with the possible exception of perhaps '89, I mean it depends on what you mean by relatively equal, but they're not always very close for all four months, or in this table I guess they're never real close for all four months.

MR. YOUNG: Right, I wonder now if I could refer you to **NP-125** please, and my understanding of this table is that it was provided, or the data was provided from the Newfoundland Power demand forecasts, that's what it says here. I note that there's two peaks in these years which are identical in the forecast, is that your understanding of this?

MR. BROCKMAN: That's what this table seems to show, although I guess there's an eight kilowatt difference there in that first line, but ...

MR. YOUNG: Yeah, that's right, but it looks to me though, that ... you're right, there is an eight kilowatt difference, but essentially this is two identical peaks for all intents and purposes, or very close to it, is that not correct?

MR. BROCKMAN: It seems to be correct, yes.

MR. YOUNG: So, I'm wondering based on the table we saw a moment ago, and based on this, whether 2-CP might be the position that Newfoundland Power ought to be supporting. I mean 2-CP seems to be the pattern we see, more than 4-CP.

MR. BROCKMAN: Well, the problem that I have with that is, as I've said, is that none of these tables address loss of load hours, first of all, which is what you use for planning your, essentially as your peak demand, if you will, when you're going to have to add something because of loss of load hours. None of these tables reflect that, and secondly of all, the months in which these things occur are always the same two months, so I don't know which two months you would pick and be fair about it.

MR. YOUNG: Well, you're on your own a little bit on that point. I think it's fair to say that all the other experts have said that that's not a relevant question.

MR. BROCKMAN: I don't agree.

MR. YOUNG: The other point I wanted to follow up on on this though, you had mentioned this loss of load hours thing, and you mentioned today a little earlier in direct, that when you do that study you get usually 60 percent from one winter month, January typically, probably 20 percent from February, so in that scenario you have two months which gives us 80 percent of the load.

MR. BROCKMAN: That's correct.

MR. YOUNG: Going further than that, I mean the numbers start to diminish.

MR. BROCKMAN: Yes.

MR. YOUNG: Fairly quickly, but it's your judgement that 4-CP is supported by the numbers that Mr. Budgell has used in his study, the same numbers that he's used for 2-CP, and I think others have suggested it could also support 1-CP, in fact Mr. Brickhill has said that.

MR. BROCKMAN: Well, again, I guess my principle reason for liking four is because I don't know which of those two months it's going to be, as well as, I guess in, I think it was Mr. Brickhill's original evidence, he was looking for stability, and when I looked at his table I saw the four being more stable, but to tell the truth, I guess I'm not really enamoured with either, between four and two, but I think because of the fact that I don't know which peak, which month it's going to occur in, I like the four better than the two, and I know that all the hours are important, but I don't see any justification for one, to follow up on that question you just asked.

MR. YOUNG: Okay, I think the best I can say about that is that the issue seems to be joined in seeing the data. You touched upon the rural subsidy issue. Now Mr. Brockman, you're a veteran, as you mentioned, of Hydro's rate applications, rate referrals, and other kinds of proceedings before this Board, and I'm trying to think of any since you've been around that hasn't discussed the issue of the rural subsidy, and I don't imagine there were any.

MR. BROCKMAN: I can't think of any.

MR. YOUNG: No, now you made a qualification today in your evidence which I thought was instructive because your pre-filed evidence at page 25 uses the words "eliminating the rural subsidy", but I think today you're talking about reducing it, is that correct?

(3:00 p.m.)

MR. BROCKMAN: Yeah, I think the word "eliminating" was perhaps too strong, because I don't know that we can completely eliminate it. I don't know that that's realistic in our lifetimes. Perhaps it is but it may be too ... I'm after a reduction as opposed to necessarily a complete elimination in my lifetime, or at least in my professional consulting lifetime.

MR. YOUNG: I'm not going to ask you when you're going to retire, I guess that wouldn't be fair. Is it the ... and I know you've looked at this before, but I don't know how much evidence you've given in this time, or that which really is intended to address this point, but I can't but ask you, is it your understanding that it's the lifeline rate in the isolated rural structure which largely contributes to the deficit?

MR. BROCKMAN: I don't know that I, at one time I probably knew the answer to that, but I haven't looked at the components of the subsidy lately, so I'm not sure I can answer that. It's certainly ... the lifeline rate is probably one of the last things we could eliminate if we decided to do that, to be realistic about it. We may never want to eliminate that, I don't know. That's something we'd have to look at down the road, but I don't know what it's percentage component is of the total subsidy anymore.

MR. YOUNG: Okay, I was going to suggest to you that that would have to be the first thing that you would have to deal with if you were really going to take a serious, serious change in the size of the subsidy, but ...

MR. BROCKMAN: Well, perhaps in the size, I agree with you, in the size, if you're correct that it is the most sizeable component, and I have no reason to doubt you. I just haven't looked at the numbers lately. That's probably where you get the most bang for the buck, but politically and realistically it may also be the hardest one to eliminate.

MR. YOUNG: Mr. Chairman, I wonder if this might be a good time to break.

MR. NOSEWORTHY, CHAIRMAN: Sure, we can if you wish, yeah. We'll break now until 20 after. Thank you.

(break)

(3:20 p.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you. Can I ask you to continue, Mr. Young, please.

MR. YOUNG: Thank you Chair. Mr. Brockman, in the context of hydrology you made reference to Granite Canal coming, being a known event the next number of years, I'm just wondering how it is that Hydro uses something in its test year which is not going to occur within the test year when we do hydraulic forecasts. I would have thought that posed a problem.

MR. BROCKMAN: Well, it's not completely outside, I guess, my experience where test years have been, I guess, the word is pro forma that the accountants use there, so if you think the rates are going to be in effect for a long time ... now if we come back for a rate hearing in, I guess I said 2002 earlier, but 2003, I guess, was the proper year, then perhaps it doesn't make as much difference, but if we thought the rates were going to be in effect eight more years, then we might try to make certain adjustments, and Granite Canal may not be the only one. There may be others that I haven't mentioned, and haven't looked, you know, looked at, where we might pro forma the test year, so I don't think it's that uncommon to do something like that if you're trying to make rates for long term, a long number of future years that you might try to bring something into the test year that you know is going to happen, very recent, you know in the very near future.

MR. YOUNG: I don't have a real clear handle on what you are proposing, I wonder do you know of any other Canadian jurisdictions that use hydroelectric production information for test years which include increases that won't occur in that year?

MR. BROCKMAN: I haven't specifically looked at that, no.

MR. YOUNG: Some of your testimony relates to weather normalization used by Newfoundland Power, and I understand that they use 30 years of data in relation to that. How is that applicable to the issue of hydrology, and is there any connection at all?

MR. BROCKMAN: Well yes, I think weather creates hydrology. You know, hydraulic generation is caused from rainfall and snowfall and precipitation in general, so that it's clearly driven by the weather so I think, you know, insofar as we looked at Newfoundland Power's number of years they use for weather related things, or Environment Canada or somebody else, it clearly drives hydrology.

MR. YOUNG: But the purpose for which Newfoundland Power uses weather normalization is quite different, would you agree than what we're using hydrology for in this case?

MR. BROCKMAN: Well, it's different, yes.

MR. YOUNG: So the Board having approved that that's in fact exactly what's occurred, the 30 year weather normalization record which may, in fact, be all they could get, all that Newfoundland Power could get, are you suggesting that it should be some sort of constraint on Hydro, since all Newfoundland Power uses for their normalization ...

MR. BROCKMAN: No, I'm not suggesting it be a constraint on Hydro, I'm just suggesting that where we're, what we're trying to do in the test year is decide what we think the expected hydraulic generation is going to be, and in order to do that we, I think it's useful to look at other places where we try to predict what we think long-run weather is going to be, and that's just one of the places where there, that we look.

MR. YOUNG: Looking in other places for things you can use and can sometimes be useful, I'm wondering if you can tell us which other Canadian electric utility uses a 30 year rolling average to forecast hydraulic production for rates or for any other purposes?

MR. BROCKMAN: I don't know that we found any that use a 30 year rolling average.

MR. YOUNG: You provided information in your most recent submission, written submission of evidence, as to the 35 year average as it is used by Newfoundland *(sic)*, New Brunswick Power, pardon me. Do you understand that there was a particular reason that 35 years was picked. It strikes me as sort of an odd number.

MR. BROCKMAN: I don't know why they use 35, no. I mean I don't know how they picked that exact number as opposed to 30, or 25, or 45.

MR. YOUNG: So I can assume though it wasn't based on weather normalization or any other sort of issue, like the 35 number doesn't match that, is that correct?

MR. BROCKMAN: I don't think it was based on weather normalization. I don't know why they picked 35.

MR. YOUNG: Okay, so you wouldn't know, for example, if that might have been the only, or the longest record that they had that was of useful information, that may or may not have been it, or ...

MR. BROCKMAN: It's possible. I mean, I doubt it, but I don't know for a fact.

MR. YOUNG: I'm just wondering if you knew that Hydro, when it used 50 years, if you thought that Hydro using 50 years was using it because it was a 50 year period or for some other reason that related to its record? What's your understanding of that choice, of the 50 year hydraulic record that Hydro uses?

MR. BROCKMAN: I'm not really sure I understand your question.

MY. YOUNG: Well, are you aware that the hydraulic record that it turns out that Hydro is using now is about 50 years?

MR. BROCKMAN: Yes.

MR. YOUNG: Did you understand that to be because we've chosen 50 years of the record or is that the full hydraulic record, or what's your understanding of it?

MR. BROCKMAN: My understanding is is that some of your records go, I think I saw some that go back into the twenties, which would be about 80 years I suppose, and some don't go quite back that far, so you know, I don't know why you cut it off at 50, I suppose there were reasons, but I don't really remember what the reason was. If even known why you cut it off at 50, I don't remember what it was.

MR. YOUNG: Okay. If I was to suggest to you that it was done because that's the period of time for which Bay d'Espoir has reliable records, would that match your understanding of that?

MR. BROCKMAN: That sounds like it, it sounds familiar.

MR. YOUNG: I suggest to you if you come back later it's going to be a longer period. It's going to go back to that date.

MR. BROCKMAN: Yes, if that's what it's tied to then it will certainly get longer as we go out in time.

MR. YOUNG: I wonder if I could ask Mr. O'Rielly to go to page 2 of your **first supplementary evidence**, please. Just go down the page a little bit please.

MR. BROCKMAN: Did you want page 2, I'm sorry, or page ...

MR. YOUNG: That's fine there, yeah.

MR. BROCKMAN: Okay, yeah.

MR. YOUNG: Would you start reading the first few sentences there on line 19, please.

MR. BROCKMAN: It says, "I recommend that the Board use the 30 year moving average. A 30 year period is long enough to minimize volatility in the average, but recent enough to reflect changes in inflow patterns".

MR. YOUNG: Okay, that's fine for the purposes of my question. Later in the next supplementary, you've discussed setting a median as a possibility. I'm just trying to get some sense of what timeframe you'd use for a median. If you're going to use median, would it be the full record or would it still be 30 years?

MR. BROCKMAN: I would still use 30 years.

MR. YOUNG: So let's say, I'm just wondering if you can respond to what other jurisdictions might do when they use median. Would they use a rolling period or would they use the longest available amount of data? Can you suggest any that use a short period of time, like 30 years and still use a median?

MR. BROCKMAN: I don't recall how those two tied together off the top of my head. I might have to get back with you on a response to that.

MR. YOUNG: Okay. If I was going to suggest to you, generally speaking, that median is a better tool to use when you have a larger data set, would that be a generally correct statement?

MR. BROCKMAN: I don't know that it's tied to the size of your data set, the median is simply a number if that you, if you want to be right half the time and wrong half the time, you pick. I don't know, that would be true whether you had, you know, 100 years or probably 60 years. Obviously the more years you have the more things are smoothed out. So, you know, if you roll the dice 100 times you're probably going to get closer to 50/50 than if you only roll them three times.

MR. YOUNG: Have you considered how useful the methods that you've proposed would have been in forecasting the 2001 hydrology. Have you looked at that issue? I wonder if I can refer you in answer to this question to undertaking, or **U-Hydro No. 17**, please, page 2. Perhaps I got the wrong page reference. Could you scroll down to the table please. There we go. No, I don't believe that's the table I was looking for. Just bear with me for a second. I'm using the hard copy.

MR. BROCKMAN: I think it is the table, I may be wrong, but ...

MR. YOUNG: If you could just bear with me for a second, I'll make ... I haven't been using the electronic copy for this purpose.

MR. BROCKMAN: Right. I think I could have answered your question from that table.

MR. YOUNG: Perhaps we can go back to the table if you think you can answer the question. There we go. Yeah, the numbers at the bottom of the page, I'm sorry at the bottom of that table, I think you would agree with me that they are fairly significantly under what you'd expect as an average, or a median that you've chosen from the 30 years, do you agree ... and your number is lower still than is the case?

MR. BROCKMAN: Well, the full average is certainly higher than the number that the 30 year average gives us in this particular year. We aren't finished with the year yet, but, yeah, the 30, the full historic average gives us a higher number in that year.

MR. YOUNG: Because we have ten months of actuals here though, correct?

MR. BROCKMAN: Right.

MR. YOUNG: And then for November and December we've used either method and what we've come up with though are numbers which are relatively low, so just looking at this one I think you'd have to agree that the full average would provide a more accurate or at least a number which is more like you'd expect to see for test year purpose.

(3:30 p.m.)

MR. BROCKMAN: I'm looking for the projection and I don't see it on this table of the actual, so that I can compare those last two numbers, you know the 3,540 is what the 30 year average would give me and 3,573 is what the full average would give me but I don't know what the projected actual is so it's a little hard to answer from just this table.

MR. YOUNG: My understanding of the table, and perhaps you can ...

MR. BROCKMAN: Maybe I mis-spoke that is the table I could use to answer your question.

MR. YOUNG: Yeah, no, that table, it looks a little different on the screen, and I looked in my hard copy and I thought it might because I got scribbles on mine, but the middle two columns there say estimated inflows from November and December, so that shows what's happened in those months for those reservoirs, and on the right hand side it says estimated annual and I take it that the last two months have been done according to the two methods, one being the 30 year average which has been proposed by you and the other being the full hydraulic average and if those two months, because obviously we don't have actuals, would show that this is our best guess based on those two methods, but in any event for the year 2001, I think you'd agree with me that we're looking at a fairly low number for hydrology.

MR. BROCKMAN: Oh yes, this shows a lower number. There's no question about that.

MR. YOUNG: And also that in a year of this sort, the full average would come closer to the sort of number you'd expect for a test year.

MR. BROCKMAN: Yeah, there are years even in the other table that's in here where I said the 20, whatever it was 16, or 13 out of the 22 years, that 30 was closer. There are certainly years where the full average is closer. Just not as many years. But this is one of the years where the full average appears to be closer.

MR. YOUNG: In your most recent evidence you made a point that Nova Scotia Power uses only 5 years of hydraulic data, for business planning and rate making purposes.

MR. BROCKMAN: That's right, according to their rate department.

MR. YOUNG: On the, you also indicate that the hydraulic generation in Nova Scotia is only about 8 percent total, is that correct?

MR. BROCKMAN: I don't remember the percentage. That sounds a little low, but it might be right.

MR. YOUNG: Okay, well ...

MR. BROCKMAN: Subject to check.

MR. YOUNG: Perhaps we can do that, because I want to make sure we're right on that one. I'm not sure of the page references offhand, but I could find the page. Page 3, thank you.

MR. BROCKMAN: That looks like it's right. Eight percent on that page.

MR. YOUNG: Yeah, now simple math tells me that if they're off by 20 percent, just say they're under by 20 percent, you're looking at two percent on total, so if you were looking at a, if you were a utility planner I understand your point you're making about it not being stabilized, but if you're a utility planner looking at realistically a swing of two percent, I mean would that cause you to have a rigorous and highly analytical look at your reservoirs or would you basically just use numbers that are going to get close. Does it matter as much?

MR. BROCKMAN: Well it certainly doesn't matter as much but as a planner and rate maker I want to get as close as I can. It doesn't cost me anything extra to use a 30 year average, or a 30 year rolling average versus full historic, so I would use the best number I could get my hands on. I wouldn't just say it's two percent so I'm not going to worry about it.

MY. YOUNG: I note on that same page, in line 15, it says, I'll just read this out. It says, "the evidence stated", this is from New Brunswick Power '93 report from the Public Utilities Commission, "it says the evidence stated that the average water conditions were determined on the basis of a 35 year historical period", a computation which is reviewed periodically, so it looks like in New Brunswick they use 35 years and I think the record is unclear here as to why it's 35 years, but it looks pretty clear that it not a median that they use, it's an average, correct?

MR. BROCKMAN: Yes, it's a simple mean, which is the average in common terms.

MR. YOUNG: I'm just wondering, on the following page, page 4, you've indicated that when you looked at the information you couldn't see a Canadian standard for any particular number of years. I put it to you that, aside from Nova Scotia Power, and I don't know about New Brunswick Power, I think the evidence here is unclear about that, but are you aware of any other Canadian utility that relies heavily on hydraulic generation. How would you make that determination as to what that means, because I never realized that's been a matter of some debate, but can you confirm that there are any other Canadian utilities that rely heavily on hydraulic generation that use some number of years for determining what they ought to use for a test year, and different from their full reliable record?

MR. BROCKMAN: I don't know that I know the answer to that from the evidence that's in this record. It appears to me to be somewhat inconclusive. You know, there seems to be a lot of different years used. I don't think that some of the evidence that we got back, either from your survey or from some of the calling we did, gave me enough confidence to believe that I know what they all do in rate making. With respect to planning I think it's a slightly a different question. I think Mr. Henderson, you know, specifically asked that question and but I don't know that I believe I know, I don't think there is a Canadian standard that I was able to discern from the records in all of those other utilities. That's just my take on the survey.

MR. YOUNG: That's all my questions. Thank you.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Young. Thank you very much, Mr. Brockman. We'll move now to industrial customers. Welcome back, Ms. Henley Andrews.

MS. HENLEY ANDREWS, Q.C.: Thank you, Mr. Chairman.

MR. NOSEWORTHY, CHAIRMAN: You look like you're in the batter's box on this one, are you?

MS. HENLEY ANDREWS, Q.C.: Apparently so.

MR. NOSEWORTHY, CHAIRMAN: If you could proceed.

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, earlier this afternoon Mr. Young asked you some questions about assignment, and in particular he asked you questions on assignment with respect to the Great Northern Peninsula, and first of all, I'd like to go back to Mr. Budgell's testimony at pages 16 and 17. That's it right there. I can see that Newfoundland Hydro has defined common plant as plant that is of substantial benefit to two or more firm customers.

(3:45 p.m.)

MR. BROCKMAN: Correct.

MS. HENLEY ANDREWS, Q.C.: And you would agree that that is the standard definition of common plant. The generally accepted ...

MR. BROCKMAN: I think it's generally accepted as well as I believe it's the standard that the Board established in their generic cost of service proceeding.

MS. HENLEY ANDREWS, Q.C.: Have you reviewed the rules that start at line 26 on page 16 and go over onto page 17 to see to what extent the rules currently proposed by Hydro match the rules that were proposed at the time of the cost of service methodology hearing in 1992?

MR. BROCKMAN: I don't know if we can scroll down to, I'll have to look at the rules. I don't remember what's on lines 26, or what line did you say they started?

MS. HENLEY ANDREWS, Q.C.: Starting there on line 26 on page 16 and going over to the end of sub-paragraph (d) on page 17. Take your time to read through them.

MR. BROCKMAN: Is there more below line 10? Can you scroll down just a little bit more, thank you. Okay, I think I agree with those in generally accepted the terms.

MS. HENLEY ANDREWS, Q.C.: My question was not whether you agreed with them but whether you have compared these which are ones proposed now to those which were proposed at the time of the cost of service methodology hearing?

MR. BROCKMAN: I don't know that I recall specifically going through these two pages saying let me check all of these against the Board's cost of service, you know, order in that proceeding, but I did in general try to make sure that Hydro did what the order said in terms of if the facilities were of substantial benefit to more than one customer class they were common, and if not they were assigned a specific. I think that's what all of these really go to. There are some more details in here but than that.

MS. HENLEY ANDREWS, Q.C.: Would you agree that based upon the definition of common plant, which has been accepted by the Board, the issue for the Board is whether any individual plant is of substantial benefit to two or more customers?

MR. BROCKMAN: I think that's the overriding principle that the Board has tried to establish, yes.

MS. HENLEY ANDREWS, Q.C.: Mr. Young asked you some questions with respect to both the Great Northern Peninsula production plant and the Great Northern Peninsula transmission plant, and you indicated that you agreed that they should be treated as common. Is that correct?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: And that is contrary to your recommendation to the Board at the time of the isolated rate hearing?

MR. BROCKMAN: I don't think it's contrary, I think certain things have changed since that time, i.e., there's been some upgrade of the transmission system, changing the character of how those facilities can be used as well as we have additional evidence from, in this record, about whether or not those facilities are of substantial benefit. I think it's in line with the principles we established in that particular case, but I think the specifics may have changed.

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, perhaps you could be shown the answer to **CA No. 2**, and I believe that's actually available, which is the 1995 Report of the Board, and go to page 42, and the page numbers, I recognize, are going to be a little bit different. Keep going, actually you should go backwards a little bit, back a little further. Just one second. Now you need to go forward a little bit. The paragraph is "The Board believes". Keep going. I know, go back again. It's hard to, one more and one more paragraph. Here it is. It's the bottom of page 39 on the screen. You will see that the discussion relates, in fact, to the results of the 1995 methodology report and the Board said it is noted that more than one customer will be served by the transmission line to the Great Northern Peninsula. Newfoundland and Labrador Hydro argues that the interconnection is of benefit in three ways. It provides additional generation reliability to all customers, now that is Hydro's position here, correct?

MR. BROCKMAN: Correct.

MS. HENLEY ANDREWS, Q.C.: The plant provides emergency backup and energy to the Great Northern Peninsula area, so that is the same as Hydro's position here?

MR. BROCKMAN: I think Hydro's position here is that it's a little more than number 2 at this point, they feel like that there's, and again I didn't really testify to this issue, but ... or at least I didn't in my pre-filed, but that they feel like there's more benefit than just the customers on the Great Northern Peninsula at this time.

MS. HENLEY ANDREWS, Q.C.: Yes, but if you look at item one, it says it provides additional generation reliability to all customers.

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: And item two deals with the Great Northern Peninsula and item three says the capacity of the plant defers future peaking capacity additions, so presumably Hydro was arguing at that time as well that item three related to all of the customers, do you agree, because future peaking capacity additions would be for the benefit of all the customers?

MR. BROCKMAN: I don't remember what exactly Hydro was arguing with respect to the details of all of that, but that sounds like it's reasonable.

MS. HENLEY ANDREWS, Q.C.: And you can see the next sentence, the Board said therefore, this is summarizing Hydro's position, the generation assets will benefit all customers and should be treated as common, Mr. Brockman contends otherwise, stating Newfoundland Power's requirements did not cause the St. Anthony/Roddickton system to be interconnected nor do Newfoundland Power's customers receive any benefit from the interconnection. So your argument at the time was that it should be specifically assigned?

MR. BROCKMAN: That's correct, at that time but as I say there have been some changes since that time to the system.

MS. HENLEY ANDREWS, Q.C.: What changes have they been?

MR. BROCKMAN: I believe there have been some transmission upgrades.

MS. HENLEY ANDREWS, Q.C.: In what respect?

MR. BROCKMAN: I don't know where, I don't recall the exact details of those but I believe that's my understanding.

MS. HENLEY ANDREWS, Q.C.: Are you, or have you forgotten that at the time of the hearing in 1995, the Great Northern Peninsula interconnection had not yet been done?

MR. BROCKMAN: I don't remember a whole lot about 1992 to tell you the truth, but it's possible that I've forgotten that. I don't know the answer to your question.

MS. HENLEY ANDREWS, Q.C.: If you look at the next paragraph which says the basis for assigning the generation plant and transmission assets in the Great Northern Peninsula interconnection is whether the assets are serving more than one customer. If the answer is that they serve only the rural classes on the Great Northern Peninsula, then they should be specifically assigned, this is the opinion of Mr. Brockman and the industrial customers. However, if the assets jointly serve the common grid, then they are considered to be common and thereby generation plant is properly assigned as common. Would you agree with me that that summary does not reflect the definition of common plant which has been accepted by the Board which is that it's not a question of whether it benefits more than one customer, but whether it substantially benefits more than one customer?

MR. BROCKMAN: I think it does, I think it substantially is part of the requirement.

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, you've indicated in your testimony that at previous other hearings before this Board you have also proposed a demand energy rate for Newfoundland Power, is that correct?

MR. BROCKMAN: That's correct.

MS. HENLEY ANDREWS, Q.C.: But at this hearing you are proposing that a demand energy rate is not appropriate?

MR. BROCKMAN: That's correct.

MS. HENLEY ANDREWS, Q.C.: And can you indicate for me what has changed since 1992, that would change your opinion?

MR. BROCKMAN: Well, as I indicated in my summary, I guess, and my evidence, after Newfoundland Power and Hydro began to discuss the issue amongst themselves the issue of revenue volatility came up and it troubled the financial planners, at least in Newfoundland Power, and I think as well in Hydro, that there was going to be extra volatility if we came up with a demand charge. So because of that reared its head that gave us pause as to whether or not this was something we really wanted to do. The other thing has changed, as I indicated, is that we haven't had an awful lot of load, demand growth in, from Newfoundland Power anyway, in the last ten years, in fact I think it's decreased, and so the reason for having a demand rate which is to try to some extent reflect the cost of demand, and perhaps control demand, doesn't seem to be quite as important as well as the fact that at the time we really wanted to have it, it looked like we needed it in order to be able to do a lot of demand side management and that issue has become less important than it was at the time. So those are the reasons that we've moderated our position on that.

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, you are aware that Hydro is currently undertaking the construction of new hydroelectric facilities to come on stream in 2003 in order to meet increases in demand on its system?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: And are you aware that Hydro is planning additional increases to its system for 2007 in order to meet projected increased demand?

MR. BROCKMAN: I know that they're planning on adding generation to the system, yes.

MS. HENLEY ANDREWS, Q.C.: Okay, and are you aware whether that, that Hydro is in fact predicting a 20 percent growth in demand over the next ten years?

MR. BROCKMAN: That's subject to check. I would accept that, I don't think it's because of Newfoundland Power's necessarily load growth, but ...

MS. HENLEY ANDREWS, Q.C.: Would you agree that regardless if whether Newfoundland Power's load grows, that anything that any of the customers do to keep the load stable on the system benefits all of the other customers in terms of potentially deferring capital cost?

MR. BROCKMAN: By stable, you mean no growth?

MS. HENLEY ANDREWS, Q.C.: No, what I'm saying is that if Newfoundland Power initiates a demand side management initiative which reduces its demand below what it is today, then not only will it benefit, but all the customers and the system will benefit from the deferral, the potential deferral of capital costs?

MR. BROCKMAN: If that demand side management program is cost effective, I think that's true in general.

MS. HENLEY ANDREWS, Q.C.: So that the, while you're correct that Newfoundland Power is not currently looking at, or is not projecting any great increase in its demand in the short term, that Newfoundland Power's control of a reduction of its demand can still have benefits for the system as a whole?

MR. BROCKMAN: Well again, I think, that those benefits would have to be weighed against the revenue volatility that they're worried about, as well as what does it do to the energy consumption, as I testified earlier, if we reduce, if we put in a demand charge and don't appropriately, and reduce the energy charge and don't do that appropriately we may create a different problem. We may find out we need base load plant because our energy is growing more than it would have otherwise. So I think you have to weigh all of those factors. It's not a simple question.

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, I'd like you to take a look at the evidence which, the pre-filed evidence which you submitted in, at the 1990 rate hearing.

MR. KENNEDY: This would be IC No. 7, Chair.

EXHIBIT IC-7 ENTERED

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, at time of the 1990 hearing, you can see at the bottom of page 13 that you were asked if you have any concerns about the rate structure proposed by Hydro in the proceeding, and you answered, yes, that Hydro proposes to continue its practice of serving industrial customers with a rate containing both a demand and an energy component, while offering an energy charge only rate to NLP and you say that this is done in spite of the fact that the cost of service study contains sufficient information to provide a demand and energy rate structure to NLP. Could you read the paragraph at lines 5 through 10.

MR. BROCKMAN: As I previously touched upon and is a well known principle of good rate making practice, the costs imposed on an electric system are primarily functions of three variables, number of customers, energy taken, kilowatt hours, and the demand kilowatts imposed on the system is also widely accepted practice consistent with the principle of ensuring rates reflect cost to therefore signal these three costs separately in customer energy and demand charges where it is practical to do so.

MS. HENLEY ANDREWS, Q.C.: Would you agree that it is still a widely accepted practice to signal these costs in separately in customer energy and demand charges where it is practical to do so?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: And you say at lines 12 through 15, that Newfoundland Power can impose any sort of load pattern on Hydro and so long as the total energy use is the same under the various load patterns, the price NLP pays Hydro is the same until Hydro has a rate referral to propose a rate change, and in the next paragraph you indicate that this is an indication of a lack of proper rate design?

MR. BROCKMAN: Yes, in the context as I'm using it.

MS. HENLEY ANDREWS, Q.C.: So when you said in 1990 that with an energy only rate there are no immediate savings to NLP and its customers for reducing its demand on the hydro system, that is equally true today, correct?

MR. BROCKMAN: No immEdiate savings. It would be as it says here through the cost of service study when you have a rate case.

MS. HENLEY ANDREWS, Q.C.: And at the time you said that, because Newfoundland Power applies demand charges to its large customers to control their demands, it would actually lose money if the customers responded properly?

MR. BROCKMAN: That's correct.

MS. HENLEY ANDREWS, Q.C.: And that's equally true today?

MR. BROCKMAN: That's correct.

MS. HENLEY ANDREWS, Q.C.: And then you indicated that another thing that the Board should consider is the effect of the hydro energy only rate on Newfoundland Power rates, which forces Newfoundland Power to have energy rates that are too high and demand rates that are too low, that is also true today, correct?

MR. BROCKMAN: I'm not sure it's true today. The forces may have been a little strong, even when I filed this evidence. It certainly, there's a tendency there for Newfoundland Power, an economic tendency for them to want to have higher energy rates because of the way, nothing forces them to do anything, I suppose. But, yeah, I still agree with the symptom. If you can caveat the forces a little bit.

MS. HENLEY ANDREWS, Q.C.: Okay, and the next sentence which says that "if Newfoundland Power is to achieve proper matching between the distinct cost causation effect of demand and energy the Board should recommend that Hydro develop a rate structure that includes these important components", you would agree that that is still true?

MR. BROCKMAN: Yes, and I think the Board did that, at least asked them to develop one.

(4:00 p.m.)

MS. HENLEY ANDREWS, Q.C.: Now at the time of the

1990 rate hearing you were also asked to deal with issues of rate design and ratcheting. Do you recall that?

MR. BROCKMAN: I don't recall it, but I wouldn't be surprised.

MS. HENLEY ANDREWS, Q.C.: In 1992, do you recall that, or would you disagree with me if I suggested to you that as a result of the 1990 hearing the Board recommended that Newfoundland Power and Newfoundland Hydro develop a proposal for a new rate structure for Newfoundland Power?

MR. BROCKMAN: I do recall. I don't recall the exact wording of the order that the Board issued on that, but I do recall that there was some sort of order that asked Newfoundland Power and Hydro to get together and come up with some sort of mutually acceptable form of demand energy rate.

MS. HENLEY ANDREWS, Q.C.: And that has not been accomplished, correct?

MR. BROCKMAN: Well they did get together.

MS. HENLEY ANDREWS, Q.C.: But they didn't come up with a mutually acceptable form?

MR. BROCKMAN: They did not come up with a mutually acceptable rate.

MS. HENLEY ANDREWS, Q.C.: I'd like you to take a look at your testimony from the 1992 rate hearing.

MR. KENNEDY: IC-8, Chair.

EXHIBIT IC-8 ENTERED

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, when you look at the bottom of page 21, the question that's posed is "Do you agree with Hydro's proposal to adopt a three part Newfoundland Power rate, with the energy charges set at marginal energy costs and the demand charge calculated as a residual?" Could you read your answer?

MR. BROCKMAN: It says "In concept I do. The details may need some fine tuning, however. I think the proposed rate gives the movement to a demand energy rate that NP argued was important in the last Hydro referral. In addition energy is given a high weight in this rate design. It should enable NP to get a good balance of peak shaving and conservation oriented DSM programs".

MS. HENLEY ANDREWS, Q.C.: So you would agree that your position at the time of the 1992 rate hearing was that there should be a three part NP rate?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: And that at that time you were satisfied that Hydro's proposal for energy charges set at marginal energy costs and demand charge calculated as a residual was generally acceptable, With some fine tuning?

MR. BROCKMAN: With some fine tuning, it says I was satisfied.

MS. HENLEY ANDREWS, Q.C.: I'd like you to refer to page 25 of that evidence. In particular starting at line 13, and I take it from the evidence at the time that Hydro had proposed a 12 month ratchet and that you can see from your answer that you preferred a non-ratcheted demand charge. First of all, can you explain what a 12 month ratchet is?

MR. BROCKMAN: Sure. A 12 month, a demand ratchet in general, especially a 12 month, as you've asked is a rate form whereby if a customer sets a certain demand, we're talking about demand now, you know not energy, but demand, if they set a certain demand of say 50 kilowatts in some month and that's the highest demand that they ever set during the year, then they're charged some percentage of that demand for the entire year and that's call a 12 month demand ratchet. Sometimes it's 100 percent of that demand, sometimes it's 80 percent, it depends on the rate design.

MS. HENLEY ANDREWS, Q.C.: Now in the case of the industrial customers, are you aware that their demand charge is based upon their amount of power on order and that it is based upon their maximum amount of power on order throughout the entire 12 months?

MR. BROCKMAN: I'm not sure what you mean by the term "on order".

MS. HENLEY ANDREWS, Q.C.: Well my understanding is that the industrial customers advise Hydro by October 1st of each year what their expected maximum demand is going to be for the following calender year.

MR. BROCKMAN: So it's a contract demand essentially, maybe there's no contract.

MS. HENLEY ANDREWS, Q.C.: Exactly, and they pay for that demand throughout the entire 12 months, whether they use it or not.

MR. BROCKMAN: Okay.

MS. HENLEY ANDREWS, Q.C.: What is the difference between that and the 12 month ratchet that you've just discussed?

MR. BROCKMAN: Well the difference is that would be a contract, if you will, contracted 12 month ratchet whereas opposed to where you're actually measuring the demand and then ratcheting it. You don't set a contract for it. It's whatever it is, and even in the sense of where there's contracted demand, I don't know what happens if the industrials go over that amount. I assume they have to pay.

MS. HENLEY ANDREWS, Q.C.: That's right.

MR. BROCKMAN: So one's contracted for, one's actually measured at a meter.

MS. HENLEY ANDREWS, Q.C.: Now in this particular evidence which you had filed in 1992, you were objecting to the demand ratchet saying it caused a mismatch between the revenues Newfoundland Power receives from its demand metered customers who were not on ratchets and the revenues they would have to forward to Hydro each month.

MR. BROCKMAN: That's correct, if there were a demand charge, a non-ratcheted demand charge to Newfoundland Power.

MS. HENLEY ANDREWS, Q.C.: And if their demand metered customers were not on ratchets.

MR. BROCKMAN: Right.

MS. HENLEY ANDREWS, Q.C.: One of the things that it appears that you were recommending if you look at page 26 is to move away from the 12 month ratchet to monthly demands?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: Without any floor on demand billing. Am I correct that the result of that would be to smooth out the volatility for Newfoundland Power in terms of revenue?

MR. BROCKMAN: Well, it wouldn't smooth out revenue, it would smooth out costs.

MS. HENLEY ANDREWS, Q.C.: Yeah, costs, okay.

MR. BROCKMAN: Actually, it wouldn't ... you say if you remove the floor then it wouldn't smooth anything, you know, it would be what it was, whatever it was in every month would be what the bill was.

MS. HENLEY ANDREWS, Q.C.: But then Hydro would be taking more of the risk.

MR. BROCKMAN: Right.

MS. HENLEY ANDREWS, Q.C.: So that what you recommended at the time would be something that would decrease the risk for Newfoundland Power but increase the risk for Hydro from a revenue volatility perspective.

MR. BROCKMAN: Insofar as it wasn't recovered through the RSP.

MS. HENLEY ANDREWS, Q.C.: And am I correct that the only explanation that you have for the change in your opinion today compared to the evidence that you gave at both the 1990 and 1992 rate hearings is related to whether or not Newfoundland Power forecasts increases in demand.

MR. BROCKMAN: No, it's two things. It's that plus the volatility that they would see under the current ... it really depends on the question of whether if they were to put in a demand charge would we modify the RSP. If we didn't modify the RSP then Newfoundland Power would also see more volatility, so it's those two things. It's the lack of demand growth for NP plus the extra volatility in NP's earnings.

MS. HENLEY ANDREWS, Q.C.: But you would agree with me and I think you did just a few moments ago, that the issue of revenue volatility can be dealt with to one degree or another in terms of the design.

MR. BROCKMAN: If we change something else then I think you're right, that it could be dealt with. If we change the RSP or change the way things are working in the RSP, then yes, we can deal with the revenue volatility.

MS. HENLEY ANDREWS, Q.C.: And clearly from your evidence at the time of the 1992 rate hearing, the fact that the issue of ratchets was, or different forms of ratchets was being discussed is an indication that the issue of volatility was being dealt with, at least discussed at that time?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: Mr. Brockman, I presume that you are familiar with the Newfoundland Power generation credit?

MR. BROCKMAN: Yes, in general.

MS. HENLEY ANDREWS, Q.C.: Okay, and I presume that you are aware that Newfoundland Power gets a reduction in its billed peak and in the peak that's used for the purpose of CP factors and also for load factor for all of the generation which it makes available to Newfoundland Hydro to meet peak demands?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: Do you agree that that is something that is very difficult to isolate in looking at the cost of service studies?

MR. BROCKMAN: No, I don't think it's difficult. I mean the demand in the cost of service study is reduced by the amount of generation that Newfoundland Power makes available, and that's not difficult to see.

MS. HENLEY ANDREWS, Q.C.: The dollar value of the credit is difficult to see looking at the current cost of service study, wouldn't you agree?

MR. BROCKMAN: Not necessarily. I believe the cost of service study reports the, what we call the unit cost in cost of service study parlance which is the unit demand energy and customer related costs by class, so it's a simple matter to multiply that number times the amount of generation, so I mean it's not a recorded number right up there but it's not difficult to see either for someone who knows what they're looking for.

MS. HENLEY ANDREWS, Q.C.: That being the point, isn't it, whether somebody knows what they're looking for and knows how to go about making the calculations that you've just described?

MR. BROCKMAN: Well, I wouldn't recommend that any layperson do much poking around in a cost of service study anyway, but ... because they may not know what they're looking at, but I don't think it's hidden in any way, if that's the implication.

MS. HENLEY ANDREWS, Q.C.: And nor is it readily available?

MR. BROCKMAN: No, I think it is readily available to an expert.

MS. HENLEY ANDREWS, Q.C.: In order to determine what the amount is, don't you have to re-run the study using the other, using the actual demand numbers?

MR. BROCKMAN: In order to ... I'm trying to think whether there might be some secondary effects that wouldn't be picked up by just multiplying that unit demand cost by the amount of generation. It's possible there are some minor, and I don't know how minor they are, but I ...

MS. HENLEY ANDREWS, Q.C.: It also affects transmission demand costs, wouldn't you agree?

MR. BROCKMAN: Yes, I mean but I ... you can get close, whether you get it exactly because of all, you know, other little things, you may be right, there may not be a way to get it exactly without re-running it.

MS. HENLEY ANDREWS, Q.C.: And would you agree that taking a generation credit approach where the amount of the available peaking capacity is deducted from Newfoundland Power's actual peak, whether or not it's used, means that Newfoundland Power gets the full benefit of the generation credit, of the generation which it has made available?

MR. BROCKMAN: Yes, I think they get the full benefit.

MS. HENLEY ANDREWS, Q.C.: I'd like you to take a look at **NP-133**, and I realize, Mr. Chairman, that it's on the screen, but it's easier for me to work from the hard copy on this one. And you can see from page 1 of 4 that question (a) is to provide the detailed calculations of the interruptible rate credit provided to participating industrials?

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: And if you look at page 2 of 4, you can see at line 6 to 7 that converting the annual estimate to a monthly rate ...

MR. BROCKMAN: Yes.

MS. HENLEY ANDREWS, Q.C.: ... it would be 14.1 dollars per kilowatt?

MR. BROCKMAN: Correct.

MS. HENLEY ANDREWS, Q.C.: But that if you look down at lines 20 to 21, the demand credit that is actually offered is $7.05 per kilowatt?

MR. BROCKMAN: Right, negotiated, some negotiated demand credit.

MS. HENLEY ANDREWS, Q.C.: Yeah, which is half of the value.

MR. BROCKMAN: It's half of the marginal cost value.

MS. HENLEY ANDREWS, Q.C.: So for its credit, the industrial customers are not getting the full value of the energy, of the demand that they are making available?

MR. BROCKMAN: Well, no, I don't think you can phrase it that way given the way you phrased your last question, because your last question was did Newfoundland Power get full credit for an embedded, from an embedded rate, and the answer was yes, but here we're talking about a marginal rate and they're not getting all of the marginal cost savings but then again, neither is Newfoundland Power. They're getting all of the embedded savings, so I think the two are apples and oranges.

MS. HENLEY ANDREWS, Q.C.: So you, and so you agree that the methodology for compensating Newfoundland Power is significantly different than the methodology utilized for compensating the industrial customers?

MR. BROCKMAN: Yes, one is based on an embedded cost of service study and the other one is based on a marginal cost of service study, plus a negotiation.

MS. HENLEY ANDREWS, Q.C.: Are you aware that at the time that the negotiation took place rates charged by Newfoundland and Labrador Hydro to the industrial customers were not regulated?

MR. BROCKMAN: I've never been completely sure of how the rates were set at that time because I wasn't privy to that, but I would accept that subject to check. I know they weren't regulated by this Board, or I don't believe they were.

MS. HENLEY ANDREWS, Q.C.: Mr. Chairman, that would be a good place to break.

MR. NOSEWORTHY, CHAIRMAN: Okay, thank you, and we'll ... thank you, Ms. Henley Andrews. Thank you, Mr. Brockman. We'll break then for, until 9:30 tomorrow morning. Thank you.

(hearing adjourned to December 4, 2001)