New Brunswick Board of Commissioners of Public Utilities

In the Matter of an application by the NBP Distribution & Customer Service Corporation (DISCO) for changes to its Charges, Rates and Tolls

Fredericton, N.B.
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	John Lawton
	John Murphy
	Arthur Adelberg
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CHAIRMAN: Good morning, ladies and gentlemen. If I disappear, it's because of the environmental hazard down here. There is a large whole in the floor. I wonder if that has been planned.

Good morning, ladies and gentlemen. Can I have appearances please? For the Applicant, Disco?

MR. MORRISON: Good morning, Mr. Chairman, Commissioners. Terry Morrison, David Hashey and with me is Neil Larlee, and Mac Ketchum.

CHAIRMAN: Thanks, Mr. Morrison. Canadian Manufacturers & Exporters? Mr. Plante is not here. Eastern Wind is not here. Enbridge Gas New Brunswick?

MR. MACDOUGALL: Good morning, Mr. Chair, Commissioners. David MacDougall representing Enbridge Gas New Brunswick and I am joined again today by Dr. Alan Rosenberg.

CHAIRMAN: Thank you, Mr. MacDougall. The Irving Group?

MR. BOOKER: Good morning. Andrew Booker for the Irving Group.

CHAIRMAN: Thank you, Mr. Booker. Jolly Farmer is not here. Rogers Cable?

MS. VAILLANCOURT: Good morning, Mr. Chairman, Commissioners. Christiane Vaillancourt here for Rogers Cable.

CHAIRMAN: Thank you, Ms. Vaillancourt. Do we have any self-represented individuals since it's in their bailiwick? The Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman. Raymond Gorman representing the Municipal Utilities. This morning I am joined by Dana Young, Jeff Garrett, Charles Martin and Michael Couturier.

CHAIRMAN: Great. Thank you, Mr. Gorman. And the Public Intervenor?

MR. HYSLOP: Good morning, Mr. Chairman, Commissioners. Peter Hyslop appearing with Mr. O'Rourke, Ms. Power, Ms. Young and today's witness, Robert Knecht.

CHAIRMAN: Thanks, Mr. Hyslop. And just for the record, if any of the Informal Intervenors are present and wish to go on the record, why give an indication after I read you out.

Agriculture Producers Association of New Brunswick, Canadian Council of Grocery Distributers, City of Miramichi, Energy Probe, Falconbridge Limited, Flakeboard Company Limited, Genco, System Operator, Potash Corp., UPM Kymmene.

Mr. MacNutt, who do you have with you today?

MR. MACNUTT: I have Doug Goss, Senior Advisor. John Murphy, Advisor -- Consultant, John Lawton, Advisor and Arthur Adelberg, Consultant.

CHAIRMAN: Great. Thanks, Mr. MacNutt. Any preliminary matters?

MR. MORRISON: No, Mr. Chairman.

CHAIRMAN: Anyone else? Okay. Mr. Hyslop.

MR. HYSLOP: Thank you, Mr. Chairman. I would like to introduce to the Board Mr. Robert Knecht. Mr. Knecht, would you please identify yourself to the panel please?

MR. KNECHT: My name is Robert D. Knecht.

MR. HYSLOP: And where do you live, Mr. Knecht?

MR. KNECHT: I live in Lexington, Massachusetts. I work in Cambridge, Massachusetts.

MR. HYSLOP: And what do you do for a living?

MR. KNECHT: I am an Economic Consultant. Part of my consulting practice involves work with regulated public utilities, primarily in the areas of cost allocation and rate design.

MR. HYSLOP: I have just noted the witness hasn't been sworn.

ROBERT KNECHT, sworn:

DIRECT EXAMINATION BY MR. HYSLOP:

Q.1 - Mr. Knecht, you have just given a series of answers prior to you being sworn concerning your name and identification. Do you confirm those answers?

A. I do.

Q.2 - Thank you very much.

MR. HYSLOP: Now Mr. Chair, I think with agreement of other counsel, it has been agreed and I would so move that Mr. Knecht be qualified as an expert in the field of electric utility cost allocation and rate design.

CHAIRMAN: That is better than just a straight economist?

MR. HYSLOP: Yes.

CHAIRMAN: Yes. The Board will recognize you as that, Dr. Knecht.

MR. HYSLOP: Thank you, Mr. Chair. And Mr. Knecht, I briefly refer you to two exhibits. One is exhibit PI-2, which was your direct evidence in this hearing. And the second is exhibit PI-3 which was your written responses to interrogatories from other parties.

Can you confirm that those documents in evidence were prepared by you or under your supervision?

A. Yes, I can.

Q.3 - Right. And is the answers and the evidence that you have contained in -- therein, are they still true or is there anything that you wish to briefly point out that may be revised?

A. The answers are true. I would like to and will as part of this direct examination, clarify one aspect of my evidence. And I guess for the record here, in the copy that was behind me there appears to be a somewhat different pagination than my version of my evidence. So we may run into some difficulties as we go along. So bear with me if the pagination doesn't match up.

But in one area of my evidence, it is on the bottom of page 13, in my copy I make some brave statements regarding

PPAs and cost causation, which I clarified in response to the interrogatory from the Public Utilities Board, PI PUB IR-1. ANd I will clarify that as we proceed with the direct examination.

Other than that, the answers are true and correct.

Q.4 - Thank you, very much. Now Mr. Knecht, can you just briefly outline the different issues that you are going to be referring to in the next 45 minutes to an hour.

A. I would like to cover the basic issues on cost allocation, the allocation of generation costs and how I approached that problem in this matter. Touch briefly on the issue of transmission costs, on distribution costs, particularly distribution plant allocation. Speak briefly about the rate design issues that I raised in my evidence and talk a little bit about the need for better data in terms of doing cost allocation studies.

Q.5 - Well let's start with generation, Mr. Knecht. When you began to evaluate generation costs, where did you begin and what steps did you take?

A. I was struck with Dr. Rosenberg's characterization last week of his threshold question, which was should we use the PPAs for cost causation or should we use -- should we use the PPAs to allocate costs or should we use some -- reach back and get a more fundamental measure of cost causation.

And I guess I started with a little bit of a different question which was in my view was there -- is there any fundamental reason why we should change the allocation methodology for generation costs that was approved back in 1992 and 1993. And that was where I began my analysis.

Q.6 - And Mr. Knecht, what is your understanding of what was decided in 1992 and 1993 regarding generation costs?

A. Well very briefly my understanding was that with respect to generation costs, the Board determined that it wanted to classify the plant related costs for generation services into both demand and energy components on a split that was 40 percent demand, 60 percent energy.

My understanding was that that classification was generally based on the Equivalent Peaker Methodology or the Peaker Credit Methodology. But I understand that the Board had other considerations in mind when it set that split.

For the fuel and variable related costs, it allocated those -- it classified those as 100 percent energy and allocated them on an overall energy basis. My understanding is that this approach was approved in the 1992 CARD decision, was affirmed in a 1993 rate decision and I think was then validated by a study prepared by the

Reed COnsulting Group in 1993, again relying on the Equivalent Peaker Methodology.

Q.7 - Okay. And on a conceptual level, can you outline to the Board what has changed since 1993?

A. Let me start with what really hasn't changed. And I think what hasn't changed is that there is a fundamental tradeoff in planning for generation assets, that there is a capital for fuel and a fuel for capital tradeoff that generation planners look at when determining what kind of capacity to build.

And in fact applying the Equivalent Peaker Methodology to the current costs or at least the 2002 costs, the classification split implied by that methodology is roughly the same as it was then.

The fundamental economics of the generation business haven't changed. In fact, most of the -- many of the assets remain the same as they were in 1992. It seemed to me what has changed is that there has been a policy change. And the policy change that indicates that the province is moving from traditional regulated service toward a market based pricing mechanism.

And leading the way on that I think is the large industrial and transmission voltage customers who are moving with the potential for market pricing a little bit faster than the retail customers. But nevertheless that is the policy change that has taken place.

Now I recognize it is early in that process. And really all that has happened thus far has been a financial and a corporate reorganization. But nevertheless there appears to be a vision of moving in that direction.

I think the key factor that has been in addition to having the distribution utility be separate, the key factor is now the distribution utility purchases generation services through power purchase agreements. And that that is the change that we might want to recognize.

Q.8 - And with those thoughts in mind, Mr. Knecht, how does this all affect your recommendations and choice of a cost allocation methodology to this Board?

A. Well in light of those changes, it seemed to me that in light of the things that have changed and in light of the things that haven't changed, it didn't make much sense to go back and start the embedded cost debate all over again. We had that debate in the early 1990s and a decision was reached. And frankly, I didn't spend a lot of time in my evaluation here looking for ways to come back and try to relitigate the allocation of embedded costs.

My sense was that that matter had been resolved and that if the Board wanted to change it, it would change it for the policy reasons that the policy of the province has changed and it wanted to change it in a forward looking way and begin to try to recognize the restructured industry in its cost allocation rather than coming back and taking another pass at the allocated embedded costs.

So this then you get to be close to what Dr. Rosenberg's threshold question is is if we are going to -- if we are going to recognize the restructured industry, should we do so through the power purchase agreements and the billing determinants in the power purchase agreements, or should we try some other approach and try to recognize market prices in a different way.

And when I answered that question I came up with basically the same answer as Dr. Rosenberg did with perhaps a little bit of a different rationale behind them. My assessment of power purchase agreements is that the billing determinants reflect only the interests of the parties that have negotiated those power purchase agreements.

They don't -- they do not affect -- they do not reflect the underlying market prices or cost causation or any of the driving factors.

Let me give you an example. I have been doing some work in Pennsylvania which is further along the road under moving to market prices, and the distribution utilities are now in the process of putting out their retail load for competitive bid. They are distribution utilities. They are going to purchase power on the open market to serve their retail load.

Now the way at least a couple of them have done it is that they put out an RFP for someone to come in and supply the load, the retail load, a slice of the system, residential, commercial, industrial, spring, summer, winter, fall, at a flat dollar per megawatt hour price.

So in essence this distribution utility is going to go and sign an agreement for a year that it's going to buy power at a flat dollar per megawatt hour price to serve all its customers. Now if we follow the PPA logic we set the rate for all the rate classes the same. But that's missing the point. Because that price reflects the underlying load shape of that utility.

So if that utility has a lot of high load factor customers that price will be lower, and it that utility has a lot of low load factor customers that price is going to be higher. And therefore, the PPA itself is not telling you anything about what is driving the underlying costs. It again is only reflecting the desire of this utility who has structured this power purchase agreement in this way.

And I think that's the same thing you see here, is that in New Brunswick they have structured the power purchase agreements perhaps mostly as a risk sharing mechanism designed to create incentives for performance for the generating companies and weren't thinking about cost causation.

And so therefore again you are looking at power purchase agreements that were negotiated for a very different purpose, not for cost causation. And that can occur with a utility like NB Power that is quite far or is just starting down the road towards moving to market prices or even jurisdictions where things have moved along much further.

So my sense is that PPAs just don't help very much in evaluating -- in telling you what cost causation is.

And finally one thing about the PPAs that would raise a concern for me I think particularly in New Brunswick where all of the parties continue to be owned by the province, is that by -- if we adopt the PPAs as the cost causation measure we are in essence ceding the cost allocation responsibility to the people who negotiate those power purchase agreements. And you are assigning that responsibility to them rather than looking at the underlying cost causation.

Q.9 - So with that background, what is your position and recommendation that this Board adopt with respect to generation costs?

A. My evidence is that the Board needs to make a policy decision here. It's not the role of an outside expert to do it. Is to make a decision as to whether or not you want to stick with embedded cost methodology and keep that in place until we get further along with market pricing, or to start moving in that direction right away and start looking at trying to get a handle on market prices and what they mean and whether that implies stranded costs or residual value or addressing some of those kind of issues. And frankly because there isn't any reason to change I don't, you know, why that if you are going to adopt the embedded cost allocation methodology you wouldn't just keep the one that you have.

Q.10 - Suppose, Mr. Knecht, the Board decides it wants to recognize the changes that have been or are taking place or expected to take place in the industry, would that change your recommendations?

A. No, I don't think it changes my recommendations but it moves it on to a different stage. It's following a different path of regulation. And I think that the first thing -- there is a couple of things that you would want to look at. The first is to look at market prices and right now there isn't really a full regional market, but you can start getting a pretty good handle on what market prices might be, by looking at the export prices that NB Power experiences when it sells power out of the local jurisdiction.

And we can look at the marginal costs -- the marginal running costs of NB Power's facilities as a proxy for what market prices might be. I think the second step is at the same time to make sure we are getting much better load research data so that we understand what the implications of the market prices are for each of the rate classes. So that if we know -- if we have some idea -- forecast our hourly market prices or look at our historical hourly market prices, we can then apply them on a class by class basis if we know what each class's load profile looks like. We need some way to take the market prices by hour and translate that back to the individual rate classes. And then when we start to collect some information in that area, then we can start to address the problems of what to do about stranded costs or what to do about the issue if we do have heritage assets and they are below the market price, which is certainly possible, we can then look at ways that we might reasonably allocate those costs, and that's an interesting question.

But to my mind even more interesting is how we start structuring the rates to try to reflect the fact that market prices are at variance with the average cost prices -- with the average cost rates that are in place right now. And there are various techniques that you could start to use to try to address that problem.

Q.11 - Now, Mr. Knecht, I understand that you were a witness in the 1992 hearing.

A. If anyone hasn't noticed, my partner, Ms. Chown, and I submitted evidence in 1991 I believe on a number of areas, particularly generation cost allocation. I have to say that was relatively early in my tenure as a utility rate analyst, and the intellectual input was mostly Ms. Chown's. But there are a number of aspects of that testimony with which I fully agree today.

Q.12 - Okay. And can you be more specific about what the nature of your evidence was regarding generation costs in 1992 and '93?

A. Well 1991 --

Q.13 - Yes.

A. -- is that -- what we did at the time, New Brunswick

Power had come in and proposed a cost allocation methodology for generation costs that was generally based on the Equivalent Peaker Methodology for assigning fixed costs while continuing to allocate all energy costs on an energy basis. We looked at the practices of all of the Canadian utilities at the time. We raised the issue, much as Dr. Rosenberg does today, and as he quoted from my evidence today that that methodology reflects one direction of the capital for fuel duality but doesn't reflect both and that you ought to reflect both.

And having analyzed all of those things we came up with a solution which said why don't you take all of your generation and your transmission costs, both fixed and variable, and simply classify them 50/50 to provide a reasonable basis consistent with the practices of the other jurisdictions for classifying what we called bulk power costs at the time.

Q.14 - And then how did your evidence at that time compare with that of Dr. Rosenberg's proposal for generation costs at this hearing?

A. We were addressing the same conceptual issue but I think we came up with very different solutions, although the two different methodologies I think produce very similar results.

Q.15 - And after the issue was litigated in 1991 and '92 what did the Board eventually decide?
A. The Board rejected the methodology that Ms. Chown and I proposed and adopted the company's proposal, I think while indicating that the company should go out and perform some additional study and I believe the Reed study was in response to that.
Q.16 - Okay. So in light of this history and in light of the conceptual position you took in 1992, why are you not agreeing with Dr. Rosenberg at this hearing.
A. Well as I mentioned it's not so much that I don't agree with him, it's that I just didn't take on that issue. My sense was that issue had been decided and to be perfectly honest if we were back in 1992 or 1993 and we had a fully integrated utility and we didn't have all this history I would probably be looking for a way to reflect the duality of the fuel for capital trade off in both ways. I don't think I would come up with Dr. Rosenberg's methodology, but conceptually I think I would be trying to address the same issue.
However, the methodology that is in place, it's been approved by the Board. It has been -- it was used by the Board in setting the 95 to 105 revenue to cost ratio range. It's the methodology that New Brunswick Power, as

far as I can tell, has used since 1993 through the 2003/2004 budget. It was the one that was available to the drafters of the White Paper when the policy change was beginning. And with all that history, I didn't see the reason to take it on again.

Q.17 - Now perhaps just going a little more into Dr. Rosenberg's position, do you have any further comment on his evidence and the position that he has put forward in this hearing?

A. I think conceptually the largest -- the most significant disagreement I have with Dr. Rosenberg is that Dr. Rosenberg is a strong proponent of using embedded costs. And embedded costs are a useful thing to use particularly for a traditionally regulated utility.

Where I think I take issue is that it's Dr. Rosenberg's position that costs will reflect market prices. And that's not consistent with my experience. My experience is more consistent with the theoretical position of economists that market prices tend to reflect the marginal cost of the most expensive producer that is being dispatched in the market.

For example, the hydro facilities at New Brunswick Power, if they were selling their power at market it certainly would not reflect those costs. So that if you have a winning technology that proves to have been a winning technology, such as the hydro assets, you are going to extract what you can from the market and you are going to price it based on the market prices which will reflect someone else's costs, not your own, and someone else's marginal costs, not your own average costs.

Similarly if you have mistakes, if you have invested too much in a plant or didn't achieve the savings you expected, the market isn't going to reward you and pay you for all those extra investments that you made that don't provide the fuel savings. You as the investor are going to have to absorb that risk and reflect that in a lower rate of return on your project.

Now if I look at Dr. Rosenberg's embedded cost method, and it's an interesting one, and it's relatively complicated by the standards of embedded cost allocation methodologies, my work on it so far suggests that this may be a reasonable approach for an optimally configured system. It would require me to do a lot more mathematics to verify that that's correct. But my simple analysis suggests that if your system is perfectly optimal, that is, you calculated your breakeven factors, your fuel costs and your capital costs haven't changed, everything is perfect, this methodology I think will do a reasonable job of allocating the costs.

But again an optimally configured system is a theoretical ideal that utilities don't ever attain. Whenever a generation planner makes his decision he has already -- he is looking at the facilities he has got in place and figures what is the next one he needs, not starting from scratch and reconfiguring the whole system.

One area in particular I think that raised some concern with me with Dr. Rosenberg's methodology is its treatment of the Coleson Cove plant's costs. And as I understand it, he determines the share that's demand and duration related using 2002 data. And with that data it looks like Coleson Cove is primarily demand related, 95 percent based on that analysis is that that plant is now -- it looks like a peaking plant. It's virtually all demand related based on the costs that are there.

So that that means that the plant costs are going to get assigned primarily on a demand basis which is going to impact the low load factor customers the most.

What happens is then when you take those 2002 numbers and move them to 2006 and apply them to the 2006, that shifts the overall demand to energy or demand duration split in the models to 47 percent demand, 53 percent energy. And that's really just by taking the different classification percentages and applying them to a different mix of costs 2006 which the primary impact is that there are a lot higher fixed costs associated with Coleson Cove in 2006. And that that's the primary change that causes the overall percentage to increase.

And then in Dr. Rosenberg's methodology, the duration costs, which are now a relatively small piece of Coleson Cove but are still their only -- they are then allocated on the basis of January load, which again the residential class or the low load factor classes tend to be a higher percentage of. So then these classes are being assigned the fixed costs for this plant and then because they are assigned a relatively high share of the fixed costs for the plant, they tend to get more of the generation costs in Dr. Rosenberg's methodology. So he uses how much you pay for each of these plants to assign the fuel costs for generation, and what that ends up meaning is that now the low load factor classes are getting assigned more of the generation from Coleson Cove than the other classes proportionately.

And this causes each class to have a different energy price in each month, and I think if driven to its logical conclusion Dr. Rosenberg's methodology will result in a different energy price in each hour for each class, which is a little bit at odds with what a market would produce. So I have a concern about the Coleson Cove unit in particular as it's implemented in Dr. Rosenberg's methodology. And I think the same -- a similar argument can be made with respect to some of the NUG generation, which if we look at it it looks like the baseload operation, but he is assigning it disproportionately to the higher energy costs for those operations disproportionately to the low load factor classes based on this methodology.

Q.18 - Perhaps to move along to another area, can you outline to the Board your position on transmission costs?

A. My evidence doesn't really address the issue of transmission costs. I have accepted Disco's proposal for allocating those costs on a 12 NCP basis. I believe that's reasonably reflective of the cost causation that comes flowing down through the open access transmission tariff. And I think it's -- there is probably some additional detail we could factor in to make it match up exactly with the open access transmission tariff, but it's reasonable for the moment.

Q.19 - Could you please comment with regard to the position of other experts with regard to transmission costs?

A. My understanding is Mr. Adelberg and Mr. Garwood have recommended the use of coincident peak for allocating transmission costs. There are some jurisdictions that allocate transmission costs on a coincident peak basis. One of the problems with that is setting rates on a coincident peak basis, because when you set rates on a coincident peak basis each customer doesn't know when the coincident peak is going to be, so each customer doesn't know what his contribution to that coincident peak will be.

And therefore some utilities -- and I know this is true in Alberta -- are kind of leery of setting coincident peak based rates and therefore I think that's probably the reason, though I was not a participant, that New Brunswick Power is using a non-coincident peak method, so the customers will know that when they experience their peak that's what they are going to be charged for under the tariff.

I think the aspect of the coincident peak methodology that would concern me the most at present is that my understanding, and based in interrogatory response from the company, is that the demand under the open access tariff includes interruptible demand. So that Disco is incurring costs for interruptible service through the open access transmission tariff based on the demand of these customers.

If we go to a 1CP method where interruptible customers are not assigned that, the costs would then be assigned only to the firm customers only. There would certainly then be a strong temptation to reduce the rates for interruptible customers which currently include a contribution to the transmission costs.

And then when the interruptible customers aren't paying for transmission service -- firm service -- then you would want to be interrupting them every time it looked like you were going to incur a billing demand moment under the open access tariff. And so then you will be looking to interrupt those customers and I don't think they will be happy with that and it's difficult to predict when those moments will occur.

So we would need to resolve the issue of whether or not interruptible service is included in the demand in the open access tariff before we can go to a 1CP methodology.

And I guess my sense is that the best way to take on the transmission cost causation issue is to take it on in a transmission rates proceeding, and to look at the cost causation issues there. That will determine how you split.

First, you will have the experts in transmission cost causation to testify at the proceeding. Second, it will determine the split between the export load and the domestic load, and then it will set the billing determinants and the cost causation factors for in-province load.

And I think when that issue gets taken on the Board should then recognize that whatever it puts into the transmission tariff will then impact cost allocation at the distribution -- for the distribution utility.

Q.20 - I would like to move on the distribution costs, Mr. Knecht. And somehow in the evidence there has been a bit of a sense that the distribution costs in the allocation really isn't that important. Do you agree with that?

A. Well not really. The -- in some of the places I have worked -- right now when a rate case comes in --I think Dr. Rosenberg alluded to this the other day -- the only costs at issue are the distribution costs. But in some sense they are not a huge cost issue as it relates to this case.

Clearly the distribution costs don't affect the transmission voltage customers, primarily the large industrial and the wholesale customers, because they are not paying for any of those assets. And, you know, it's relatively small as a percentage of the overall costs for

Disco when we include generation costs. I calculated that at about 17 percent of the total costs are costs that are not related to either generation or transmission.

But that still comes to $200,000,000, which strikes me as a good sized number. And when I look at it, if I look at Disco's cost allocation study and I look at a residential customer who is not an electric heat customer, some 36 percent of that customer's costs are related to things that are not generation or transmission. So we get up there over a third of what goes into -- what goes into a customer's bill who is not buying electric heat, that starts to be significant.

And finally the issue I would raise is that when we look at distribution costs, not only are we allocating the costs but in the classification stage when we split the cost between demand and customer components, we are sending a cost signal that relates to what the customer charge should be, the fixed dollar per month charge. And depending on how we do that allocation it has implications for what that customer charge should be. And again that's a big -- you know, that can be a big factor, particularly for low income customers.

Q.21 - What seems to be the key issue coming out of these hearings regarding the allocation of distribution costs.

A. I guess there is two generic areas. One is the classification of plant, the split into the demand to customer component, particularly for poles, conductors and transformers. The second area -- and that first area is one that I raised in my evidence. And the second one is another issue that is typical for distribution class which is how you allocate overhead costs. And I believe Ms. Zarnett provided some evidence with respect to some of those costs.

Q.22 - And what are the different alternatives that are being put forward during these hearings by the different parties.

A. Well generically there is three basic methods for dealing with distribution plant cost classification. One is the minimum system method which splits costs into demand and customer components based on the cost of what it would require if you put in the minimum sized piece of equipment for the entire system rather than the actual equipment that is in place, and that that minimum system would represent the customer component.

There is another method that is used in some jurisdictions which I call the 100 percent demand method which is to classify all of transformers and poles and conductors cost as demand related.

And the third is kind of a hybrid method which addresses one of the complaints about the minimal system approach. It's called the zero intercept method. And it essentially sets the customer component at the theoretical level of a distribution system with zero load carrying capability. So that it's like a minimum system approach with zero -- where the minimum system has zero load carrying capability.

Q.23 - Which system do you favour and recommend and would you briefly explain why?

A. If the data are available and -- there is a data issue involved in this, but if the data are available, I much prefer to use the zero intercept methodology because it addresses this problem with the minimum system approach. The common complaint is that the minimum approach has load carrying capabilities, so you are including demand related costs in your customer component and by using the zero intercept approach and by setting the system to zero load carrying capability, you have avoided that problem. With respect to the other method, the 100 percent demand related or basic customer method I think Mr. Adelberg and Mr. Garwood call it, it's hard to ensure that there is -- it's hard to prove that there is a customer component of cost to the distribution system, but I think we all feel like there is one. We all expect that if you add more customers -- if you add more small customers, say ten five kw customers, it's going to cost more than one 50 kw general service customer, and that that ought to be reflected in the cost classification. And for that reason I prefer to take sort of the middle approach which produces a result in between the two, and that's the zero intercept method.

Q.24 - I would like to move on a little bit to some rate design issues, if we could, Mr. Knecht. And first of all rate design for the residential class. Dr. Rosenberg noted, everyone here seems to agree, eliminating the declining block is appropriate. First, do you agree and do you have anything to add?

A. Yes, I agree. I think everyone is in agreement that the larger customers tend to be temperature sensitive in New Brunswick (Technical Difficulties)

CHAIRMAN: Are you ready to go again? Go ahead, My Hyslop. Put the question again.

Q.25 - Thank you very much, Mr. Chairman. Again, I think we were looking at the residential class rate design and the issue of the declining block. And perhaps you could state your position and any other comments you have with regard to that.

A. I agree with Dr. Rosenberg that we -- and I believe Disco and I believe everyone in this proceeding agrees that we ought to eliminate the declining block rate structure because the large low load factor customers if anything, cost more to serve than the smaller customers.

And I guess the issue is it's a question of degree, how fast can we move to getting that done. And obviously in the interim since the time I filed this evidence, rates are changing. I had put a proposal into my evidence, it's probably not relevant now given the changes that have taken place, but it seems to me that what the Board I think needs to start doing is to start setting some guidelines for how quickly we can move, and what sort of advice or direction can we provide to the distribution utility for phasing these things out.

And that I think would be to set some standards which say, look, the top ten percent of residential customers shouldn't face a rate increase over the course of the whole year that's more than one-and-a-half times the rate increase for the residential class or more than two times the rate increase for the residential class. But it would be to set some more specific guidelines for phasing this thing out as quickly as we can.

The second thing I think I would raise is that -- that

I learned subsequent to filing my evidence -- is that there are a number of farms and perhaps churches that have relatively large loads that are served under this tariff. And I think my advice would be to not let a relatively small number of customers that are in a rate class that isn't really applicable for them determine the fate of the vast majority of the customers within that class. And that if we need to continue to provide some protection to the farms for policy reasons or just general gradualism reasons, perhaps it would be better to either impose a cap on those customers in some way or to pull them out into a separate rate class for the moment and phase them in to rates over a longer period of time, but not to let them distort the tariff structure for the vast majority of the customers.

Q.26 - There has been suggestions in the evidence that since 1993 the utilities move slowly with regard to this issue which was an issue at that time. And are there reasons that the utility might want to continue to move slowly?

A. Well there are a number of reasons why the utility might want to do that. I raised one in my evidence which is that by keeping the tail block in the rate structure lower it actually lowers the revenue risk of the utility to weather fluctuations.

The higher that tail block is the more their revenues are going to fluctuate when you get a cold winter or when you get a warm winter, and therefore they face a little more risk. There is other reasons which is it's difficult, and the utility is going to take a lot of public pressure when they change rates from -- you know, from phone calls and complaints and complaints to the policy makers.

So there is both a kind of a hard financial reason and a set of political reasons why progress might be slow. And while the Board directed the elimination of the declining block tariff structure way back then, the progress has been quite slow.

Q.27 - Moving on, if we could, briefly to issues of rate design for general service. Do you have some thoughts or recommendations on that, Mr. Knecht?

A. Again I'm in agreement with Dr. Rosenberg and Disco that we ought to phase out general service II, the all electric tariff. We ought to do that as quickly as possible.

In particular I would be concerned about the grandfathering proposal, because when you grandfather a customer class you are essentially giving them low cost rates and all new customers that are coming on are going to face the higher rates in the general service I class, and because you are dealing with business customers you are creating a competitive advantage for people who have the entitlement to this service over new entrants in, and you are creating what could be a competitive distortion.

And therefore when you grandfather the class and have done that, which I am not objecting to, all I'm saying is that that makes it more important to have this tariff out more quickly. And all I recommend in my evidence -- I didn't put together a rate design proposal for GS II -- but when you allocate the revenue increase to each of those classes you would do it in such a way as to assign a much larger piece to the general service II class to move the rates in line more quickly.

Q.28 - And finally throughout these hearings, there has been references to the need for different and maybe better data to do cost allocation studies. And do you have comment with regard to what is available and some of the directions we might want to go for the future in terms of data for cost allocation in New Brunswick?

A. I raise a number of issues in my evidence on that and I'm not going to go through all of them here, but cost allocation studies is like any other computer model. If you have got garbage in you have got garbage out. And in going through many of the assumptions that Disco's model relies upon, there is a lot of information that is quite old. The load factors for general service customers, one interrogatory response suggested it went back to information provided by Mr. Vanderbeen in 1988, back before I was here last.

I looked at the residential load factor forecast as we went through the series of cost allocation studies and it seemed like the company had been consistently under forecasting the residential load factor, suggesting maybe the load research data are not that accurate or it may simply be weather factors.

There is -- and I think Mr. Adelberg and Mr. Garwood also raise a good issue which I touch on obliquely in my evidence, which is that the cost split between the functionalization of costs and the distribution plant between primary and secondary is -- could use a little additional analysis.

So I think that restarting the effort on the load research, restarting some analysis of the plant costs between primary and secondary assets would help a lot, particularly if we are moving in the direction of moving to market prices to reflect the policy changes.

MR. HYSLOP: Thank you very much, Mr. Knecht. This completes the direct examination, Mr. Chair and I leave Mr. Knecht available for cross examination by any other party.

CHAIRMAN: Thanks, Mr. Hyslop. Is it Mr. MacDougall next?

MR. MACDOUGALL: I believe so, Mr. Chair.

CHAIRMAN: Right. Okay. Good. You would like to move up, Mr. MacDougall, with your expert?

MR. MACDOUGALL: Yes, Mr. Chair, please. It will just take me a moment.

CROSS EXAMINATION BY MR. MACDOUGALL:

Q.29 - Good morning, Mr. Knecht. Good morning, Mr. Chair, panel.

A. Good morning, Mr. MacDougall.

MR. MACDOUGALL: Mr. Chair, just a couple of starting comments. My understanding is that Mr. Knecht's evidence was filed in two volumes, a confidential version and a redacted version.

There are a couple of question that I have that go to the confidential portion, but I have designed them to be asked in a way that don't raise any of the confidential information, although they are in the section of the confidential piece.

Depending on how Mr. Knecht answers them, we should be able to stay totally with that version. If not there may be a need at some point just to close the process for one or two questions. But I have attempted to try and do it in a way that that will not have to occur.

CHAIRMAN: Sounds good, Mr. MacDougall. Some people might be wondering if you are trying to tell him how to answer the question.

MR. MACDOUGALL: Not at all. Mr. Chair, the vast majority of what I will be referring to is Mr. Knecht's evidence and his information request responses which are PI IR-2 and PI IR-3, which I believe you all have in front of you. I have maybe half a dozen other references but those two documents are primarily what you should have today.

Q.30 - Mr. Knecht, if I could start just there were a few issues in your direct that I would like to go to. So I don't have prepared questions so just bear with me as I go through a bit of this and I am just going to try to think back to a couple of comments you made this morning that were not otherwise in your evidence previously. And I just want to try and go through those before I get to my prepared cross examination.

You were talking about Dr. Rosenberg's approach to Coleson Cove. And I would just like to ask you a few questions around that topic to start with.

Just to basically reiterate, would you agree that the theory of capital substitution is you spend capital to save fuel costs?

A. Yes.

Q.31 - Okay. But for Coleson Cove, they have not achieved this, correct? They spent capital but they are still using oil, not orimulsion, correct?

A. That is my understanding. I believe they spent capital for a number of purposes, one of which was to enable it to use orimulsion. But yes, generally.

Q.32 - Correct. But if you are looking at the capital substitution model in the way Dr. Rosenberg did, capital spent on Coleson Cove to allow it to use cheaper fuel did not occur because the fuel is still expensive. Correct?

A. That is correct.

Q.33 - Thank you. So higher load factor customers, under what you said this morning, would get allocated the higher capital cost, but they would see none of the fuel savings because they still have the higher fuel. Correct?

A. I'm sorry. Say that again.

Q.34 - Under what you said this morning, if you didn't -- if you changed the allocation for Coleson Cove, higher load factor customers would get allocated the higher capital costs, but they see no fuel savings because the capital that was spent isn't reducing fuel because orimulsion isn't being used. Correct?

A. Yes. I agree with that.

Q.35 - Thank you.

A. I think to clarify the answer I do agree with that. What happens is because the cost increase comes between the time the capital cost increase isn't reflected in, as I understand it, the classification split in Dr. Rosenberg's methodology because the costs in 2002 are much lower than the capital costs in 2006. So that he hasn't allocated those capital costs to the higher load factor customers because it has been using the 2002 data.

Q.36 - Understood. I just wanted to get clear though what has happened with Coleson Cove as between capital and fuel.

A. Yes, sir.

Q.37 - Okay. Now on the issue of hydro, you also spoke about that as an issue in Dr. Rosenberg's testimony. You cannot dispatch hydro in merit order, can you, in New Brunswick?

A. My understanding is, reflecting on what I said about hydro in Dr. Rosenberg's testimony, but yes, I mentioned it with respect to the difference between average costs and market prices, not with respect to cost causation. But yes, I agree with that. I believe that. I believe they are runner river plants and they run when the water is flowing.

Q.38 - That's right. One of the IR responses, I can't recall, that NB Power said they are primarily runner river, correct. And were you here last week when Dr. Rosenberg indicated to the Board that if they had some issues with the nuance of how he approached hydro, that they could certainly look at that differently in the manner in which they finalize cost -- class cost allocation study?

A. I was not here. I did read it in the transcript.

Q.39 - Great. But he did say that?

A. Yes.

Q.40 - If we could go now to A-16, Mr. Chair, and this is one of the two places where I have to refer to something else. So it is A-16, Disco EGNB IR-36.

MR. DUMONT: Could you repeat the reference please?

MR. MACDOUGALL: Yes, I can, Commissioner. It's A-16 and then if we could go to Disco EGNB IR-36.

Q.41 - Are you there, Mr. Knecht?

A. Yes, sir.

Q.42 - And this was in the subsequent filing and what was asked here, there was a reference to table 2A, schedule 4 1 of the June 1993 analysis by Reed Consulting Group on cost of service issues which portrays the Peaker Credit Method.

And there was a question posed by EGNB, please update this table for fiscal year 2005, 2006. Do you see that question?

A. Yes.

Q.43 - Okay. Would it surprise you that Dr. Rosenberg asked EGNB to ask that question on his behalf?

A. No.

Q.44 - And can you read the answer please? Just the first paragraph.

A. Disco has updated the above referenced analysis to Handy-Whitman Electric Utility Price Index used in the original analysis index to capital cost is only available up to 2001, 02, therefore the analysis was done for that year.

Q.45 - Okay. Yet EGNB on behalf of Dr. Rosenberg asked for it to be updated to 2005, 2006, correct?

A. Yes.

Q.46 - And the company updated it to when?

A. My understanding is 2002. I certainly would agree with the intent of the question which would be to make the analysis consistent with the timeframe for the cost allocation study.

Q.47 - Sure. And intervenors can only operate and prepare evidence based on the data provided to them by the utility?

A. I am painfully aware of that.

Q.48 - Yes, I am sure you are. Thank you. Now sticking with your comments from this morning, Mr. Knecht, I am just going to flip through my notes here if you would bear with me for a second. I believe and unfortunately I don't have the transcript. No matter how quick the transcribers are, they couldn't do it that quickly, I'm sure. But I believe at one point, and maybe you can correct me if I am wrong, you stated that Dr. Rosenberg had indicated that embedded costs will reflect market prices. Is that what you said?

A. If I said it that way, I may have overstated the case. What I believe is in Dr. Rosenberg's evidence, I believe that he said the other day -- and the transcript will read what it says -- but that rather than price based on marginal cost, firms -- and I believe he quoted Dr. Kahn -- that prices will reflect cost.

And when you say cost and we are in a utility proceeding where we are allocating embedded costs, I had perhaps assumed that he was referring to embedded costs.

Q.49 - Okay. And that was the reference --

A. That would be the cost if we looked at the income statement for a hydro generator, its cost would be its embedded costs.

Q.50 - Fine. That's great. Thank you. And I think one last question on your discussion this morning. I believe at one point you indicated that markets do not have different energy costs in each hour. Do you believe that? Are you saying that market pricing doesn't change in markets on an hourly basis?

A. No, that's not -- that's not what I was saying. What I was saying was that within an hour, if a residential customer goes to purchase the energy in that hour, he will be charged the same price as an industrial customer going to purchase that same energy in that hour.

It doesn't matter which class you're in in that hour. It matters only -- the same price applies to anybody who goes to buy in that hour, which is different I think than what Dr. Rosenberg's method will produce if he actually broke it out and went hour by hour.

Q.51 - Okay. But you weren't saying that markets have different energy costs in each hour? They certainly can, correct?

A. I mean, some markets, I guess on a five minute basis. So I was using an hour as a proxy for when prices change. But yes, prices can change on a five minute basis. But in any particular duration over which the price is set, anybody can go buy at that price, not -- there is no differentiation between rate classes.

Q.52 - And I will hold that thought because I have a series of questions on that. So if that is the point you are making, I will come to those later on. But I will come back to that.
CHAIRMAN: Mr. MacDougall, have you finished this, it would be a good time to take a 15 minute break.
(Recess - 10:30 a.m. to 10:45 a.m.)
CHAIRMAN: Go ahead, Mr. MacDougall.
MR. MACDOUGALL: Thank you, Mr. Chair.
Q.53 - Mr. Knecht, a couple of the areas I am going to go over I know you have addressed this morning in your direct, but there is a few things I want to just reiterate as part of my cross examination, but some of it I have reduced after some of your comments from this morning.
Q.54 - I am going to make a couple of general comments on your evidence. I don't think we have to go to any specific pages to start with, but in your direct evidence which is your exhibit PI-2, you referenced three approaches to generation cost classification and allocation as I understand it, being that you call the traditional approach, the PPA causation approach and the market approximation approach, correct?
A. Yes.
Q.55 - And my question was going to be is would you say that

the choice of which approach to take is essentially the threshold question with respect to cost of service referred to by Dr. Rosenberg, and I think this morning you said it was generally the threshold question, but you were thinking along more lines of policy going forward, is that correct?

A. Yes. I started with a different question, perhaps because I appeared in the hearings in 1991. And therefore I started with the question is there any reason to change that because it's difficult to come in and say well I recognize what you said in 1991 and I want another go at it.

Q.56 - But at the end of the day, the threshold question does come down to which one of the approaches to take before you move forward with your analysis?

A. The threshold question is which one of the three, yes.

Q.57 - In your case it's three, that's correct. And also in your evidence you discuss your view of certain advantages and disadvantages of each approach, correct? That's how you have laid your evidence out?

A. I did.

Q.58 - And let me, I have just got a comment I want to make, which leads to my question, from my reading of your evidence you did not specifically indicate a preferred

approach to the Board. Rather as I read it you state that if a traditional approach was deemed reasonable, you recommend continued use of the approved methodology until such time as market based pricing is more fully established, and if a market based approach is deemed to be preferable, you recommend the Board direct Disco to upgrade its load research and file a cost study based primarily on marginal system costs applied to hourly cost load information in its next general rate proceedings? Do I have that correct?
A. I think so. Are you referencing a specific part of my evidence?
Q.59 - It is. It's at the bottom on page 19. And I guess I just paraphrase. I apologize for that.
A. This is where we have a pagination issue, but --
Q.60 - It's the second paragraph, the question, so with all this background?
A. Yes.
Q.61 - And you start at my line 25, if a traditional approach is deemed to be reasonable --
A. Yes.
Q.62 - -- and then on the next page, if a market based approach is deemed to be preferable. So you are leaving that decision to the Board? You are not making a

recommendation to the Board?

A. I needed to file a study to use for allocating revenues and for designing rates and in that I used the methodology that was approved in 1992. And I did that for the reasons both that it is the approved methodology and because the analysis that I was able to do of the marginal cost information suggested it was not unreasonable at least for the period for which I had that information.n.

Q.63 - And I will get to a discussion on your marginal cost pricing shortly. And I also understand and it's also on page 19 -- and again I am not too sure of the specific line reference, but you state that because the PPAs -- and you mentioned this this morning -- are not market based and appear to be relatively unstable, you do not recommend the PPA cost causation approach be used at present, is that correct?

A. That's the -- what it says in the evidence here. And I think I have expanded that. I have spent a little more time thinking about it --

Q.64 - Yes.

A. -- and in looking at some places where you actually have market based and arm's length transactions, and I can look at the agreements for purchasing power that come out of that and say those would not be a useful basis for allocating costs. And therefore, I think I went a step further than what I actually had in this evidence is that it would be a very unusual circumstance where I think the PPAs would perfectly reflect cost causation and, therefore, I do not recommend using it.

Q.65 - Perfect. And you I think used the Pennslyvania example this morning, as well?

A. I did.

Q.66 - Now if we can look at what you call the traditional approach, and again, your definition of the traditional approach is on page 12, and while I am making page references, we will go slowly here and make sure that we can get to the right questions, because of the pagination issue raised. But on my page 12, there is a bullet called, Traditional?

A. Yes.

Q.67 - And if I can just read in what you have written there. This approach is based on a traditional demand energy classification scheme wherein generation costs are split between demand and energy classifications using a standard methodology such as the Equivalent Peaker or Fixed Variable Approach. Correct?

A. Yes.

Q.68 - And in the same paragraph, in the last sentence, you

not that in short, this approach is consistent with the issues that were addressed in the 1992 CARD proceeding and you have mentioned that earlier today as well, correct?
A. Yes.
Q.69 - Now if we could go to page 13. And again, for me it is at line 5. And it is the question, what are the advantages and disadvantages of the traditional approach? And at line 5 you state, At this stage, NB Power continues to incur costs on functions much in the manner of an integrated utility. Virtually no competition currently exists and NB Power continues to plan its generation requirements in a centralized manner. Correct?
A. Yes.
Q.70 - And do you still agree with that statement
A. Yes.
Q.71 - Okay. And you would agree that this is consistent with the view given by Dr. Rosenberg last week?
A. On this subject, yes.
Q.72 - Thank you. Now Mr. Knecht, you were here during the cross examination of the Disco witnesses when your counsel, Mr. Hyslop, referred them to the New Brunswick White Paper on energy policy, were you not?
A. Yes.
Q.73 - And do you recall that he took them through the

conditions for achieving the competitive wholesale power market in New Brunswick that were proposed by Navigant Consulting Inc in that White Paper?
A. Yes.
Q.74 - And my understanding of that cross examination was that Mr. Hyslop, the counsel who is proffering you as a witness today, was eliciting from the panel that the conditions or prerequisites put forward by Navigant in the White Paper for achieving a competitive wholesale market have not been achieved. Is that correct?
A. I think that is a fair summary.
Q.75 - And is it your recollection that the panel's responses were clear that a competitive wholesale market in New Brunswick has not yet been achieved?
A. Yes.
Q.76 - And Mr. Knecht, what is your opinion of when a competitive wholesale market for electricity in New Brunswick will be achieved? Your personal opinion?
A. I don't have one.
Q.77 - Now I think I need more than that.
A. I will explain why I don't have one. Because developing a competitive market in New Brunswick will depend on forces that are outside of my control and it will depend on someone who -- someone or some set of

entities who want to push the process forward and then being able to achieve that.

And that would understand -- require I think understanding a lot more of the politics of the province than I have and I think it would presuppose me deciding what the Board is going to rule in this case with respect to the policy matters.

You know, if the Board decides it wants to start moving aggressively towards market based pricing, I think it can be a significant push in moving that forward. If they don't then the process will be much slower.

You know, as a general matter, certainly my experience in other jurisdictions is the transition from a traditional regulated industry to a competitive one takes some time. But it can happen.

Q.78 - Okay.

A. And does and has.

Q.79 - Now if we go to page 19 again back to the traditional approach. Again it was at line 25 in my copy, what you stated there was if the traditional is deemed to be reasonable I recommend continued use of the approved methodology until such time as the market based pricing is more fully established. Is that correct?

A. Yes.

Q.80 - So is your opinion on when market based pricing would be more fully established the same as the comments you just gave, or do you have a greater view of when market based pricing will be more fully established in New Brunswick for the supply of electricity, for generation?

A. I think that -- to clarify this sentence I think which needs a little clarification, is that if the Board decides now it wants to move and start to reflect market based pricing through proxies, such as export prices or through marginal costs, it can start moving towards at least market based or market anticipated prices fairly quickly. That may not require the development of a fully competitive market before we make that step to changing the way we do the cost allocation.

Q.81 - Let me probe that a bit. I mean, to me what you seem to be saying here if is the traditional approach is deemed to be reasonable, you recommend the continued use of it until such time as market based pricing is more fully established. My understanding there is that you are talking about market based pricing for the supply of electricity to Disco.

A. Yes.

Q.82 - We are not talking about the Board making the decision. We are talking about whether or not there is a market for

the supply to Disco, correct?
A. I don't believe that is correct. I believe that if this Board wants to decide -- if this Board decides that it wants to move to market based pricing and it feels like it has enough information from the marginal cost and export prices to start moving in that direction, or at least to start looking at the implications of that, that we don't need to wait until we have a fully competitive market to do that.
Q.83 - So what was the purpose then, getting back to Mr. Hyslop's questions last week, of whether there was a fully competitive market or not? He is your counsel. He asked a series of questions outlining that there was not a fully competitive market. I thought we agreed that that was what he was trying to show.
My understanding he was trying to show that in that what we are talking about when we talking about market based pricing is whether or not Disco is seeing market based pricing, isn't that correct? I'm confused if it's not.
A. One, I am not going to comment on Mr. Hyslop's intentions because I'm not sure what they were. This is a number of factors that could influence what the purpose of his cross was and unfortunately lawyers can't be cross

examined. So I don't think --

Q.84 - Very fortunate. On that we certainly agree, Mr. Knecht.

CHAIRMAN: Wait to the summation.

A. I don't believe we will be able to do that. And, you know, I don't know why that would influence the -- my testimony here.

Q.85 - Okay. Well maybe I misread that and we will move on. Certainly that is not what I thought your evidence was suggesting, because if we go to the next page it says, if a market based approach is deemed to be preferable you recommend that the Board direct Disco to upgrade its load research. So you are either going to have a market based approach or you are not going to have a market based approach, correct?

A. Right. But when I'm saying a market based approach I'm not saying you have to have a fully competitive regional market with divestiture of assets and all kinds of competition going on. You can start to reflect what that might look like in your cost allocation study by looking at proxies for what the market price might be.

Q.86 - So you are suggesting that you can start doing that even if there is no competitive market for the supply of generation to Disco?

A. Yes.

Q.87 - When do you expect market based pricing to be fully established for the supply of generation to Disco? Let's talk about how I see the picture. When do you think Disco is going to start seeing market based pricing?

A. I don't know. I would anticipate that that would take some time.

Q.88 - Yes. Some time.

A. For Disco to see market based pricing you would need to have competition. You would certainly be looking at some way of divesting or at least reducing the concentration of the generation companies, the market concentration of the generating companies that are in place right now, and to provide for some competition between -- and I think I agree with the White Paper's analysis that you need to have a regional market to get going to have enough scale -- to have full competition.

Q.89 - Okay. And I had a few prepared questions. I think I am going to skip through most of them. Just suffice it to say on this point for example the PPAs are long-term in nature, right? They are a long-term supply contract.

A. That's my understanding.

Q.90 - And we made reference a couple of times -- I don't think we have to turn up the Disco business plan -- that says Disco is not currently looking for any new capacity until 2014 or '15, have you heard that a couple of times?

A. Let me go back to my previous answer, just to make sure it's clear. My understanding is that while the PPAs may be long-term in nature, that at least the Nuclearco one is being renegotiated. So I saw a number of interrogatory responses, so, you know, a long-term contract that gets renegotiated on a regular basis may not be quite so long-term, but --

Q.91 - But they are for the heritage -- the supply of generation from the heritage assets is the reason for the PPAs?

A. That's correct. Let me go back to your next question --

Q.92 - Thank you.

A. -- and maybe if you could repeat it for me.

Q.93 - Just that the Disco business plan and Mr. Larlee subsequently indicated that Disco did not see the need for further capacity until 2014 or 2015?

A. That's correct.

Q.94 - Thank you. Mr. Chair, just because of that line of cross was a little different than I had anticipated, if you give me a minute I think I can knock some of my questions out here.

So we can agree though that there is no existing market in New Brunswick for the supply of generation to Disco, correct?
A. I'm sorry. I just missed a piece of the question, that's all.
Q.95 - We can agree that there is no competitive market for the supply of generation to Disco currently?
A. Well there is not what I would describe as a fully competitive market. There are generators, both industrial generators and some generators selling to Disco. I wouldn't describe it as fully competitive but Disco is out procuring generation and there is some competition from self-generation.
Q.96 - Who are they procuring generation from other than through the vesting agreement and the (inaudible) agreement, other than through their affiliated companies?
A. I guess they are not -- they are procuring it through Genco, that's correct. The NUG contracts come through Genco.
Q.97 - Correct. So they are procuring everything from the two affiliated companies, correct?
A. Right. It's not a competitive market for Disco but --
Q.98 - That's what I asked.
A. -- Genco that is what you asked and I apologize for

not answering your question. But there is that NB Power can go out there and procure power from companies it doesn't own.

Q.99 - No competitive market for Disco?

A. It's not a fully competitive market. I believe at some point -- well Disco doesn't need to procure capacity right now. It has plenty through its heritage assets. So it's certainly a very thin one, if at all.

Q.100 - If at all. Okay. And you talk about a market approximation approach. So what market are you suggesting the Board approximate?

A. The regional market for power.

Q.101 - So the Atlantic market, the New England ISO markets, that's what the Board should start approximating, although Disco isn't saying any of those prices, is that what you are suggesting?

A. Well yes, I am suggesting that if the Board wants to move in that direction, that the prices that Genco sees on its exports would be at last a first approximation to what those market prices would look like. And when you say Disco doesn't see any of them it doesn't see them directly but it certainly does observe a credit coming back from Genco related to the sales to those markets.

Q.102 - And I'm going to get into exports in a little more

detail, so maybe I will leave that there. But I will come back to that topic.
Now if we can go to page 14, line 12, still talking about your market approximation approach, that's page 14, line 12 in my version. There is a statement there, however, because the market approximation approach is based on marginal costs, it is theoretical economic advantages as well, but I just want to key in on your comment there. You say that the market approximation approach that you are discussing is based on marginal costs, correct?
A. Yes.
Q.103 - Did you provide a full marginal cost study as part of your evidence?
A. No.
Q.104 - And I think we could turn to these IRs -- there is a couple of IRs, maybe we don't have to, but it is your recollection that you don't have indicated the IRs that you do not have sufficient information to prepare a marginal cost study for generation costs?
A. Yes.
Q.105 - Do you believe anyone in this proceeding has sufficient information to prepare a marginal cost study for Disco's generation costs?

A. I believe Disco does.
Q.106 - And they haven't shared that information?
A. Yes, that's correct.
Q.107 - Did you ask them for information to be able to prepare a marginal cost study that they had and they didn't give to you?
A. I'm not sure I asked them for sufficient information. I certainly asked them for marginal cost information for the 2005/2006 year which would at least give me a pretty good start on it.
Q.108 - What was their response?
A. They didn't provide that and to be honest, even for Disco I think it would be very difficult --
]Q.109 - Thank you.
A. -- to conduct a marginal cost study primarily because the load research -- they have the marginal costs, they would then need to assign those on a rate class basis and the load research may not be adequate for that at present.
Q.110 - And in fact you are suggesting to the Board if they wanted to go in that direction they would have to get updated load research, correct?
A. I would like to update the load research anyway, but it would be particularly important I think if they are moving in that direction.

Q.111 - Exactly. Thank you very much. If we could go to your response to PI EGNB IR-6. This would be in PI-3, information request responses. I think that is the exhibit. And the question is PI EGNB IR-6.
And if we are all there, at the end of the response to PI EGNB IR-6 you state, please note also that I do not advocate the use of marginal cost analysis for allocating transmission and distribution costs in this proceeding. Is that your evidence?
A. Yes.
Q.112 - So are you advocating to the Board that they might move towards using marginal cost for the generation of electricity, but not its transmission or distribution?
A. Yes. And for the very reason that I was using marginal cost analysis was not to use marginal cost analysis but to approximate market prices.
Q.113 - Okay.
A. And I don't need to try to approximate market prices for transmission in distribution services.
Q.114 - But isn't the supply to Disco of electricity for the foreseeable future a de facto monopoly in the same way that transmission or distribution is? There is no market prices.
A. We have agreed that's the case and if the Board wants

to move toward market pricing it can use this as a proxy, but it's anticipating -- it's anticipating moving to a more competitive market for --

Q.115 - Okay.

A. -- that we have agreed does not really exist right now.

Q.116 - Are you aware of any economics text that advocate the use of marginal costs for one set of services but not for another set of services?

A. I could not quite -- I could not cite an economic test -- an economic text that says that. Economists in general like to go with marginal cost pricing to the extent possible. Regulators like to go with embedded costs in many ways because of the stability aspects of using that approach.

And in many cases the regulation of public utilities is a balancing act in trying to design rates that reflect marginal costs while allocating other costs on an embedded cost basis. So it just -- to answer your question directly it doesn't seem like the sort of question an economic text would address as to why you couldn't apply an embedded cost methodology for a product that is basically regulated and use a marginal cost methodology for a product that is moving towards a competitive market.

And I guess I don't see any inconsistency there.

Q.117 - Okay. Could you explain to the Board what the problem of the second best is as explained by economists in general?

A. You are getting into theoretical economics that may not necessarily --

Q.118 - Well I am getting back to this question.

A. -- it may not necessarily by my strongest suit, but the problem with second best usually applies to how one attempts to set prices when you do not have the economist's theoretical idea of perfect competition.

Q.119 - And would it be fair to say that if you price one commodity or one item at marginal cost but not another competitive item at marginal cost, that you don't necessarily come out with the second best solution, you might come out with a worst solution? Isn't that really what the theory says in practicality?

A. If you have two competitive products and one can be priced in marginal cost and one is not priced in marginal cost, there is certainly a possibility that you don't get the best second best solution -- the second best solution to that problem.

Q.120 - Correct. That's why it's called the problem of the second best, correct?

A. There are -- you know, there are -- if I understand your question, you are getting at the issue of how you reconcile marginal cost analysis with rates that need to be average cost based and how you move from marginal cost pricing for some services and reconcile that with average cost pricing. And yes indeed, there is sub-optimal solutions to that problem.
Q.121 - Exactly. Sub-optimal is what you said?
A. Yes.
Q.122 - Correct. Now if we can go to the top of page 15. This is page 15 of your evidence. Sorry. I'm back to your evidence.
A. Yes.
Q.123 - And here you indicate starting at line 1 -- on mine it's line 1 anyway, it's a new paragraph -- the disadvantages of the market approximation approach are practical ones. The methodology requires a forecast of hourly marginal dispatch costs. Okay.
Then you go on to state, while NB Power apparently prepares such a forecast with PROMOD and any such simulation requires a large number -- any such simulation requires a large number of assumptions which may be debated in regulator proceedings. Correct?
A. Yes.

Q.124 - So would you agree that many of these assumptions would require the application of judgment?

A. Yes, I certainly agree that judgment applies in all cost allocation analyses.

Q.125 - And not all parties would necessarily agree on the assumptions?

A. It would be unusual if all parties agreed on all the assumptions.

Q.126 - Correct. Now if we could go to page 20, line 4, you start by saying, in the interim -- and this is the interim if the Board does not move towards a market based approach -- you say, in the light of the analysis that suggests that the cost of serving industrial load on a marginal cost basis is not noticeably lower than serving the rest of the load, the traditional approach is best retained. Correct?

A. Yes.

Q.127 - Now when you are talking about an analysis here, you are talking about your analysis, correct? An analysis that you carried out?

A. Yes.

Q.128 - But as you already stated you did not do, nor do you have the data to do a full marginal cost study, correct?

A. Yes.

Q.129 - And as we discussed earlier, the traditional approach is an embedded study such as the Equivalent Peaker or Peaker Credit method or the Fixed Variable Approach, correct?

A. Yes.

Q.130 - So you are using a partial marginal cost analysis for one select customer class without the full data to support your use of an embedded approach?

A. Well rather than to say that it supports the use of the embedded approach, it doesn't suggest that it would at least for the data that I was looking at was going to produce a wildly different result.

And again this is under the -- you know -- under the assumption that the Board wants to move in that direction and in looking at that analysis it gave me some comfort in filing a cost allocation study in this proceeding to allocate revenues and design rates that I could work from that was consistent with the historical practice and at least not inconsistent with the marginal cost analysis I could do.

Q.131 - Yes, but the analysis you did wasn't the full marginal cost study?

A. That's correct.

Q.132 - And it dealt only with one select customer class?

A. Well you can't really deal with only one. It was one class and -- in fact it was one class and all other classes. So you could look at the implications of it for a 100 percent load factor customer, which is what I did, and then assume the rest of the system is the all other class.

Q.133 - Yes. But you didn't do it for residential, GS I and GS II. You did it for the large industrial and all other classes?

A. That's correct.

Q.134 - That's correct.

A. Because we don't have the load profile data for each of the classes.

Q.135 - Correct. You don't have that data. And it wasn't a full marginal cost study. Now in looking at the large industrial class in this analysis you only looked at short run marginal cost, is that correct?

A. Yes.

Q.136 - Mr. Chair, here is where some of my references might go to the confidential material but if Mr. Knecht answers as he just did, similarly we will never get there. So hopefully -- it's hard for yes to be confidential.

A. I will endeavour not to use any numbers in my response.

Q.137 - If the answer is no, you can say no, but if it's one word that's very helpful. No, I think we are just in this area, so I just want the Board to know I will be very cautions right now and I will step back and I should let my colleagues behind me know to grab me if they feel I am treading on too thin ice.
Do short run -- I guess I want to turn this around. Short run marginal costs do not reflect the cost of additional capacity, do they?
A. I'm not sure I would agree with that. There are certainly competitive markets both in electricity and in other commodities wherein the short run marginal costs reflect -- in periods of very tight capacity you get extremely high spot prices which are from the marginal cost of a producer that would not normally be economic and is therefore providing a return to capital, and creating the incentive for new capacity to come on line. So there are circumstances under which you have a very high cost producer -- a very high marginal cost producer that would not be economic and therefore the market price signal is -- includes capacity costs that would encourage the addition of new capacity.
Q.138 - Okay. So you are saying in some instances short run marginal costs may reflect the cost of additional

capacity?

A. They will certainly reflect the shortage in a market and therefore provide some return or an incentive -- return to capital or a return for investment in the market.

Q.139 - But you didn't, as we just discussed -- well I just asked you the question, the short run marginal cost you used in your analysis did not reflect the cost of additional capacity, correct?

A. That's correct. I did not observe that kind of behaviour in the marginal costs that I used.

Q.140 - So the short run marginal costs you were using do not reflect the cost of additional capacity, correct, which is the normal situation?

A. Again --

Q.141 - Well did they or did they not reflect additional capacity?

A. Remember that marginal costs is going to be the marginal cost of the high cost producer in a market, therefore every producer who is contributing to that market or every producer -- every generator who is being dispatched has a cost of operation that is at or below that level, to the extent that the variable cost is below that level of the marginal cost it is earning a return on its capacity.

Q.142 - Let's go then, Mr. Knecht, to your response to EGNB IR-5 which is in PI-3. And if we go to EGNB -- your response to EGNB IR-5 A but there is only an A, and if we go to the second sentence, I am going to read this out. Short run marginal cost studies, however, may not reflect the cost of additional capacity, whereas long run marginal cost studies typically will. That is your evidence? You wrote that response?

A. I did indeed.

Q.143 - Thank you. No, that is fine, Mr. Knecht. I just wanted to know it you wrote that.

A. I did indeed and it will --

Q.144 - And that is generally the view, is it not? Are you saying the general view is that short run marginal costs reflect capacity? That is a yes or no question, I think.

A. Short run marginal costs will reflect a return to capacity for all generators that operate at a level below that. Now --

Q.145 - What generators are we talking about?

A. When I wrote this, what I was thinking about was that there is a model -- there is a mathematical model of optimal generation in which capacity costs are priced at the cost of a peaking unit and all energy is priced at the marginal cost of operation in whatever hour that you are looking at. And therefore, you get both the fuel for capital and the capital for fuel tradeoff in that kind of a model.

And I believe when I wrote this response that is what I was thinking about, which was the marginal cost is reflecting some element of capacity but it may not be reflecting that peaking unit, the capacity costs related to the peaking unit.

So I am distinguishing here between capacity costs meaning a return to the nuclear plant when marginal costs are $50 a megawatt hour and the nuclear plant is running at $4 a megawatt hour, clearly it is getting a return on capital. The marginal cost when a combustion turbine unit is on margin and it is the last unit dispatched, it is going to return its fuel costs, but it is not providing any return to capital.

Q.146 - Okay.

A. So the marginal cost analysis doesn't provide a return to capital to the last unit dispatched, but it does provide a return to capital for every unit below that.

Q.147 - In New England is there an electricity market?

A. Believe it or not, I do almost -- I do no regulatory work in New England. It is my understanding there is --

Q.148 - There is a New England ISO?

A. There is a New England ISO.

Q.149 - And there is a market?

A. There is a market.

Q.150 - Are you aware that there is a separate capacity market?

A. I haven't looked at the New England ISO market in a lot of detail and would hesitate --

Q.151 - Would you be surprised?

A. I would not be surprised, no.

Q.152 - Is there a market in New York?

A. Yes.

Q.153 - Are you aware if there is a separate capacity market in New York?

A. There is a capacity charge in the New York market. The cost is relatively small compared to the energy costs.

Q.154 - There is a capacity charge?

A. The capacity charge is relatively small in New York.

Q.155 - Are you aware of PJM as an electricity market in the US?

A. Yes.

Q.156 - Are you aware that it has a separate capacity market?

A. I believe it does. It would not be --

Q.157 - You wouldn't be surprised?
A. I wouldn't be surprised, no.
Q.158 - Separate from energy, correct?
A. Yes, but at least my experience is that what you -- that the variation you see and where all the costs are are in the energy charges and it's dominated by the energy charges. And indeed, in many places there is a difference between on-peak and off-peak energy which is quite significant.
Q.159 - That is exactly where I was going with my next question.
A. I suspected it.
Q.160 - We are on the same wavelength here, Mr. Chair. Of course, I am going to turn that around a little bit since you answered that way.
Are you aware of any competitive wholesale market in the US or Canada where over the course of a year on-peak energy process are not much different than off-peak energy prices?
A. I have not studied that.
Q.161 - Would you -- do you think that that would ever be the case? That is not generally the case, correct? I mean, you just really answered it.
A. My experience in what I have seen is that there are

differences between the on-peak and the off-peak prices that are not insignificant.

Q.162 - Thank you. Now I just want to ask this one question. I think we have answered it and again it does deal with pages 15 through 17, which are confidential parts. But you did some analysis there.

I am just going to ask you a generic question. In your analysis on pages 15 to 17, do the figures include a review of marginal capacity costs?

A. No.

Q.163 - You know exactly how to answer the confidential questions, Mr. Knecht, yes or no.

Now on page 16, and again in these pages, Mr. Chair, as I say, I am going to continue to try and stay away from anything specific. The first bullet you are referring to average on-peak and off-peak marginal costs. Correct? Without getting into the numbers? You reference is to, in line 1, average on-peak costs?

A. Yes.

Q.164 - And then it says compared to off-peak marginal costs -- compare them, you are comparing them to average off-peak marginal costs, correct?

A. Yes.

Q.165 - Now if you do a marginal cost study in jurisdictions where you have the data to do it, do you look at average marginal costs or do you look at marginal costs in each hour?

A. You would look at marginal costs in each hour. But for very high load factor customers, if you are just evaluating the very high load factor customers, the variation is going to be small because it is going to average out because it's a high load factor customer.

Q.166 - To do a marginal cost study though, you look at costs in each hour and in fact some of your questions were asking for load research to get the hourly load data, correct?

A. Yes.

Q.167 - Thank you. And again, without trying to break any confidences, I am just going to ask a very general question on your figure IEC2. Without referencing any of the numbers, the spread from the least expensive hour to the most expensive hour is significant in that diagram. Isn't it?

A. Yes.

Q.168 - Thank you. Now the second bullet on page 16, you talk about NB Power's use of exports. The sale of exports by NB Power, would you agree that these are generally opportunity sales? They are making them when they can make money?

A. Well presumably they make them when they have capacity available.

Q.169 - Yes.

A. Which I think is a definition of an opportunity sale. And in fact the marginal cost of supplying the export market is less than the price that they can obtain from the market.

Q.170 - And would you concur that Disco's obligation is to serve native load in New Brunswick? I don't think it requires a legal analysis. Just as a regulatory expert, its obligation is to serve the native load? That's its franchise?

A. It's -- I do hesitate to reach a legal conclusion. It certainly has an obligation to serve its firm customers. And --

Q.171 - That's fine.

A. Well there is an issue, I think, of a policy matter with respect to the interruptible load and this is not -- the interruptible or surplus load in New Brunswick and this is not an issue that I raised in my evidence. But Disco prices its interruptible load at its incremental cost to serve. And as I understand it, that is an incremental cost before it serves the export market.

And in so doing, it is foregoing an opportunity to earn margin on its export sales that would otherwise be credited back to the firm service customers. So that when there is a policy matter with respect to pricing interruptible service as to whether or not it should be a marginal cost before the export market is considered or with the export market considered as well.

Q.172 - Okay. But you would agree --

A. You are getting into a legal issue there, I think, with respect to whether it has an obligation to supply --

Q.173 - Let me just ask this. The interruptible customers that you are talking about are large customers situate in the province of New Brunswick?

A. Yes.

Q.174 - And Disco does have a standard supply service that they are entitled to? I don't think that is a legal conclusion. You are probably aware of that?

A. Yes.

Q.175 - Just because I am from there, I will ask this. You may not know. Are you aware of the Nova Scotia Board's recent findings with respect to whether or not interruptible customers should be charged after or before exports?

A. No.

Q.176 - Would you be surprised if that Board found that the exports should come after the fact so that native load is being served at the marginal cost necessary to serve that load in the province? Would that surprise you?
A. No. But I guess I am not that easily surprised.
Q.177 - You raised a new issue and it just happened to be an issue that Nova Scotia had just dealt with and so I thought -- and I am aware of that so I thought I would --
A. I will look it up. It is an interesting issue.
Q.178 - Now dealing with exports, do you expect Disco will be able to maintain its level of exports when Point Lepreau is being refurbished and over 600 megawatts are offline for a minimum of 18 months?
A. Again, this comes under -- my response comes under the answer all other factors being equal --
Q.179 - Yes.
A. All other factors being equal, no, the loss of the capacity is going to presumably reduce the export load unless, you know, unless the export load is fully constrained by transmission constraints rather than by economic constraints. And the answer to that is I don't know. So if the export market is not currently constrained by transmission constraints, which -- then all other factors being equal, yes, I would assume that

exports will decline when Lepreau is being refurbished.
Q.180 - And now would you agree that Point Lepreau is one of, if not the lowest variable cost base load plant in New Brunswick because it's a nuclear plant?
A. Yes.
Q.181 - And I guess you jumped ahead again, exports can be impacted by transmission congestion?
A. Yes.
Q.182 - Are you aware if there is any transmission congestion in the New England ISO?
A. I don't know. In reading the White Paper I noted that at the time there was certainly transmission restraints in serving that market from New Brunswick. It was identified as an issue.
Q.183 - And I would have been surprised at that except for your caveat earlier because you do live in the Boston area, right?
A. I brought a copy of my electric bill for my attorney to look at to show him what it -- you know -- how bad it could get.
Q.184 - We will come to that. But even though you are a cost of service and rate design expert living in New England, you are not aware of transmission congestion issues in New England.

A. That's correct.
Q.185 - Okay. So would it be fair to say that New Brunswick Power's exports would vary from time to time and are impacted by various considerations?
A. That's a fairly vague statement and I think it's safe enough, yes.
Q.186 - Now you have made some comments and I think they are on page 16, line 8, of my version, and again this is in the confidential material but these are not confidential. On a marginal cost basis -- and these are your words -- the cost of supplying a 100 percent load factor customer was only slightly lower than the cost of supplying NB Power's weather sensitive load.
In that regard if I could just ask you, can you indicate in any jurisdictions in North America which have some measure of retail competition that you are aware where the percentage of residential load by megawatts leaving the system is greater than the percentage of industrial load leaving the system for competitive supply, is there any retail jurisdiction where a higher percentage of residentials are leaving the system than industrial? Are you aware of it?
A. I have not provided -- I certainly have not done an extensive study of that. It certainly is my understanding

that -- in both electricity and gas -- that the load most likely to leave the traditional supplier is the large industrial load.

Q.187 - Exactly. Good. Perfect. And now I'm going to get back to a point you raised earlier today that I think we are going to have a difference on, but maybe not. But from what you said today -- let's see if we can get to the same place. Is it your understanding that in such jurisdictions competitive suppliers are giving the same price offering to residential customers as to high load factor customers?

A. No.

Q.188 - Okay. But you said earlier today when talking within an hour that they were seeing the same price, but now you are saying competitive suppliers are not giving the same price signal because obviously a high load factor customer is one who would be given a better price signal, correct?

A. When you asked the previous question that I answered very briefly to, no, I was assuming that we were talking about a price over a longer period than one hour, that we were looking at a price over a year or -- presumably over a year.

So that when you offered service to residential customers you were recognizing that that is a lower load impacted customer and that in fact there is an on peak and off peak price differential and maybe seasonal price differential as well, and therefore it was most likely that the cost to serve the residential customer on average was higher over that period than the cost to serve a high load factor industrial customer over that period. Not because the prices to each were different in each hour but because the consumption in each hour was different between the residential load and the industrial load.

Q.189 - Perfect. That's fine. I think we are on the same page. And as you said, the price offering to the residentials is different from that to the high load factor industrial.

A. But again that's -- you know -- you have to look at it on a case by case basis.

Q.190 - Sure.

A. You can't simply assume that that's going to be the case in New Brunswick. That's the case, you know, where I observed it which, you know, as I have said is not an exhaustive study of all the markets that are out there.

Q.191 - No, but I'm asking for your observation. Now if we could go to page 14, line 17 though 21, and I think we have managed to get through the maze of confidentiality without breaching any, Mr. Chair, and I don't think I will be coming back there.

So page 14, lines 17 to 21, and in my version this is the second paragraph under the question, and market approximation, and I just want to read out the line there starting at line 17. "It can be mathematically demonstrated that for an optimally configured electric utility the cost of providing service is equal to the variable generating cost of the last unit dispatched, i.e., marginal cost, multiplied by the kilowatt hour generated in each hour, sum it over all hours of the year, plus the fixed cost of a peaking unit multiplied by the total generating capacity required to serve the load." That's correct?

A. Yes, sir.

Q.192 - Okay. And I think you raised an issue today about optimally configured, so let's come to optimally configured in your evidence. Here we are talking about an optimally configured electric utility, correct?

A. Yes. An optimally configured electric utility is one where the amount of capacity has been set, as Dr. Rosenberg's evidence explains. You calculate the breakeven factors, you line that up on the load duration curve and you figure out what the capacity should be.

Q.193 - Okay. Now NB Power is not optimally configured?

A. No utility is optimally configured.

Q.194 - Good. Thank you.

A. That's probably a little bit aggressive but I certainly have not observed one that is optimally configured. And the reason for that is that the breakeven factors you have to calculate are based on the variable cost of running it and fuel prices, you know, change on a regular basis. So the breakeven factors change and therefore the optimal capacity numbers change.

Q.195 - Sure. Okay. Now if we cold go to page 39 of your evidence, line 26, and again this is under a question, can you address Disco's concern ..., and this is the second bullet. It starts with the word second.

In my line 26 it's the wording in the brackets that I want to concentrate on, because you chose an example. You say, "in fact in Quebec the enabling legislation mandates retention of historical revenue cost ratios which exceed 115 percent for large industrial customers."

A. Yes, sir.

Q.196 - Do you see that?

A. Yes.

Q.197 - Can you tell us the average industrial rate in Quebec?

A. Not off the top of my head.

Q.198 - Could we ballpark it?

A. For the heritage pool the generation costs are about two-and-a-half cents a kilowatt hour.

Q.199 - Two-and-a-half cents per kilowatt hour?

A. Two-and-a-half cents a kilowatt hour. Yes, it's quite impressive.

Q.200 - Yes, it is.

A. They are doing some interesting things with the allocation of marginal costs of the non heritage pool assets there too, but I don't think that's the thrust of your question.

Q.201 - No. The thrust of my question was the two-and-a-half cents a kilowatt hour.

A. Yes. That's the price for the heritage pool generation. I believe incremental generating costs are about eight-and-a-half cents a kilowatt hour.

Q.202 - Yes. But what they are seeing is two-and-a-half cents.

A. Well they are starting to see some of the eight-and-a-half cents too.

Q.203 - Primarily two-and-a-half cents a kilowatt hour.

A. But for all of their incremental load they are going to be charged 115 percent or upwards of that of the eight-and-a-half cents per kilowatt hour.

Q.204 - That's right. Okay. I think I know the answer to

this, I think you mentioned it this morning. Is it your understanding that the PPAs charge Disco at Genco's or Nuclearco's marginal cost of production?
A. No.
Q.205 - And the PPAs are therefore not market based, correct?
A. Yes, I agree.
Q.206 - Yes, they are not?
A. Yes, they are not.
Q.207 - And the PPAs arose out of the restructuring of NB Power?
A. Sorry?
Q.208 - The PPAs arose out of the restructuring of NB Power?
A. The PPAs are necessary or some mechanism is necessary by which the distribution utility which is providing service purchases power for its customers.
Q.209 - And they deal with the heritage assets of NB Power primarily?
A. I guess you could call them that, although as you corrected me earlier, I believe they are now including some non-utility generation in there.
Q.210 - But that was non-utility contracts that Genco had prior to restructuring?
A. If you want to include that in the heritage generation, then yes.

Q.211 - Yes. So government policy as reflected in the PPAs does not reflect the use of marginal cost pricing, correct?
A. Well as I mentioned I don't believe the PPAs -- yes, that's correct.
Q.212 - Thank you.
A. But I don't believe that they were structured in a way to provide input to cost allocation. They were structured for other reasons that I talked about earlier.
Q.213 - That is your understanding?
A. Yes.
Q.214 - And who in government have you talked to about that?
A. I have not spoken to anyone in the New Brunswick government about that.
Q.215 - Thank you. So as long as Disco is purchasing electricity under the PPAs, it will never see Genco's marginal cost of production, correct?
A. It depends on what you mean by never see it.
Q.216 - What I mean is it will not be given a price for the electricity that is equal to the marginal cost of production?
A. Disco will on an incremental unit of demand in the short run coming from -- at any hour coming from Disco's customers under the PPAs as written, you will not -- Disco

will not get charged the marginal cost for that incremental unit in the short run.

However as I think both Dr. Rosenberg and I agree is that over the longer term what Genco is going to need to charge Disco is going to reflect some of that -- it is going to reflect some of the different load and different hours. So if the load patterns change, those charges are going to need to change and therefore that PPA variable charge price is not long-term reflective of cost causation.

Q.217 - Isn't what the PPAs will do over the long-term is recover the total cost of production? They won't be recovering or showing any marginal cost price signal to Disco. They are designed over the long-term to recover their total cost of production. I'm certain that's in one of the IR responses. I'm not sure that I have it.

A. That's my understanding. All I'm saying is that the total cost of production is going to reflect the cost causation factors and those prices may change in reflection of the cost causation charges.

Q.218 - But marginal costs don't always reflect the total cost of production because you said in your evidence and Adelberg and Garwood and everyone has said you often have to reconcile that to total cost. PPAs are not showing the marginal cost to Disco at any time.

A. Not only are they not showing a marginal cost but they are probably not showing a useful embedded cost signal either.

Q.219 - But over the life of the PPAs they are going to recover their costs?

A. They will, but again you can't use them to pass on rates to individual rate classes because it's not reflecting -- while the average price -- again remember the Pennsylvania example --

Q.220 - Yes.

A. -- while the price that's coming out may be what Disco sees, it's not reflecting the underlying nature of cost causation.

Q.221 - And that is right. On that we totally agree. I just wanted to make sure that we were also clear that there was no marginal price signal being given to Disco through the PPAs.

Q.222 - Now, I know this morning you talked a bit about your previous evidence before this Board. And I think there is a few questions that I would like to follow up on in that regard.

MR. MACDOUGALL: Mr. Chair, I am going to refer to EGNB IR-1. This is -- or the PI's response to EGNB IR-1, in exhibit Public Intervenor 3. So we are in Public Intervenor 3, response to EGNB IR-1.

However, I believe that response stated things would be filed in the electronic form and I am not sure if the Board was given in the all of the hard copies, including all of the binders. So maybe people -- maybe Mr. Chair, you could advise me if you actually have the hard copies of the evidence for the --

CHAIRMAN: I have no idea.

MR. SOLLOWS: IR-1.

CHAIRMAN: IR-1.

MR. MACDOUGALL: IR-1, Mr. Chair. EGNB 1.

CHAIRMAN: Yes.

MR. MACDOUGALL: And there it said in response to IR -- and copies of the evidence are provided in the electronic format?

CHAIRMAN: I don't think we do, frankly.

MR. MACDOUGALL: I can -- I have make copies on the assumption that the electronic format may not --

CHAIRMAN: Yes.

MR. MACDOUGALL: And what this was is you see from (a) to (e), there is five documents --

CHAIRMAN: Yes.

MR. MACDOUGALL: -- they were provided to everybody electronically, including to the Board electronically. I am going to refer only to one of them, which is Mr. Knecht's testimony before this Board in 1992, but because I thought they may not all be filed behind you or because there would be hundreds of pages, I have made copies of the relevant --

CHAIRMAN: Thank you very much.

Q.223 - Mr. Knecht, do you have a copy of that? He wrote it --

A. I would be presumptuous. I believe Ms. Chown wrote most of it.

MR. MACDOUGALL: Mr. Chair, I am just going to ask my colleagues --

CHAIRMAN: I don't there is any reason to mark it as an exhibit, Mr. MacDougall.

MR. MACDOUGALL: No, no.

CHAIRMAN: It all forms part of the evidence anyway.

MR. MACDOUGALL: Mr. Chair, I am short one.

CHAIRMAN: I recognize the exhibit number from the early 90s.

Q.224 - Now, Mr. Knecht, if we could go --

MR. MACDOUGALL: Oh, Mr. Chair, just to let you know, I believe for the sake of expediency I only copied the actual direct testimony -- there is a bunch of appendices, which would have made the document much bigger. And I am not referring to any of appendices. And I don't think Mr. Knecht is going to have to bring us there. So everybody should have 26 pages, but you shouldn't take that as the whole document. I just copied those pages I was going to refer to.

Q.225 - So, Mr. Knecht, if we can go to section 313 of page 8. And here there is a title, "The Capital for Fuel Trade Off", correct?

A. Yes.

Q.226 - And I think -- I was going to read some of this in -- but based on some of your comments earlier today, is it fair to say that the capital for fuel trade off you are discussing here is virtually identical to that which Dr. Rosenberg has put forward in his testimony? The issue of the capital --

A. I think conceptually Dr. Rosenberg's testimony in this proceeding is consistent with the testimony of Ms. Chown and I in 1991. And is consistent with the paragraph that he read from my evidence in this proceeding is that this capital for fuel trade off goes both ways. And that my view of the Equivalent Peaker is that it doesn't -- that it doesn't reflect both of them.

Q.227 - Correct. Thank you. And your view on the capital for fuel trade off, as put forward in this evidence, has that changed, your general philosophical view on the capital for fuel and fuel capital trade off?

A. On the nature -- on the dual nature of that, no, it hasn't.

Q.228 - No.

A. I believe that the paragraph that Dr. Rosenberg read is very similar to this.

Q.229 - Great. Thank you very much.

MR. MACDOUGALL: Mr. Chair, if you give me a moment, I think the answer there may have helped us move quite quickly so. Mr. Knecht, now if we can -- I was able to knock a few questions out there -- move to page 13 in the same document. Page 13 in his evidence in the 1992 proceeding. His 1991 evidence, I think it was -- that's correct, 24th of September 1991.

And if we can look at section 3.2 at the bottom of page 13, and that's entitled, "Seasonality in the Cost Allocation Study"?

A. Yes, sir.

Q.230 - And if I can read in the first paragraph there, "A cost allocation study should result in costs being allocated to customer classes in direct proportion to the load characteristics that give rise to these costs. It is well-recognized in utility rate setting that the cost of service can vary substantially across the different seasons of the year, as well as during the different hours of the day. Even if this difference is not fully recognized in the rate structures, it is fair to say that some classes with pronounced seasonal patterns give rise to proportionally greater costs." Do you still agree with that statement in principle?

A. Yes. If both the costs and the load patterns have corresponding seasonal patterns, yes.

Q.231 - Correct. Now if we could go to the last paragraph and if I could read that in. "Customers with pronounced seasonal patterns should bear the higher cost of service in the winter months. Thus we recommend that the Board require NB Power to account for the seasonal use patterns of the different customer classes by allocating costs on a seasonal basis. NB Power's proposed allocation of demand-related costs already reflects seasonal use, as these costs are allocated to customer classes based upon use during the system peak. However, energy costs, notably fuel costs, are allocated without regard to seasonal electricity consumption. We recommend that energy costs be determined by season and then allocated to each customer class based on its electricity use within each

season." Correct?
A. Yes, that's what it says.
Q.232 - Do you -- did you make a recommendation such as that in this case?
A. Whether you do a -- whether you reflect seasonal cost allocation depends on your overall method of cost allocation. And in fact as we discussed earlier in the -- you know, the ideal optimally configured utility where you price your capacity at the cost of a peaking unit and you price each hour at the marginal cost of dispatch in that hour, that marginal cost pricing will reflect the seasonality.
So that if you do go to a market based or a marginal cost based pricing scheme to the extent that there is seasonality in the marginal costs, you will in fact reflect that seasonality.
Q.233 - What about if you don't go to a marginal cost based system?
A. If you use the existing methodology and that was the -- I think the thrust of our point here in 1991 -- is that the existing methodology does not reflect the seasonality of costs, at least as we perceive the seasonality of costs to be occurring then.
Now, you know, then when we looked at the seasonality

of costs, we were looking at, you know, an integrated utility and we were doing embedded cost analysis. And that's the framework in which this recommendation was made.

What I suggested in this proceeding is if we want to not continue the existing methodology and the Board decides that, then if we want to reflect seasonality, we would do it looking forward market based rather than on an embedded cost basis.

Q.234 - But you have told the Board that if has an option of going market based or traditional based, so if it doesn't go market based, are you saying that your evidence that you should recommend the seasonality in what was at that time as I understand generally a fixed variable or embedded study that you are changing your view? You don't believe that should occur in an embedded study?

A. It's not me that is changing my view, other than I am simply accepting the fact that the Board rejected this methodology.

Q.235 - But you recommended it?

A. I did.

Q.236 - And --

A. And as I said --

Q.237 - -- and others are recommending in this proceeding?

A. I am sorry.

Q.238 - And others are recommending seasonality in rate design in this proceeding?

A. Yes, I understand. But again I started from the question of is there any reason to change the methodology that's in place? And my answer was, yes, if we are going to start looking forward and moving to markets. And if we are simply -- nothing else has changed in any significant way since then and, therefore, at some point, you know, you say to the Board, you have made this decision, let's move on.

Q.239 - No, but we are asking your view. Your view of the evidence was that the Board should do this and others are also putting that forward. I mean, this Board should certainly look at the views of parties as to what they think the right thing is in current circumstances, should it not?

A. Right. And this was -- this was -- you know, this was -- that I think that you ought to -- this is getting at the same issue, which is that the fuel per capital issue, and this was the way that we recommended in be approached in that proceeding.

And as I said in my opening statement, if we were back in 1992 or 1993, I probably would make this recommendation again. Just we have a long history since then.

CHAIRMAN: Mr. MacDougall, how much longer do you have and should we take our luncheon break now?

MR. MACDOUGALL: Mr. Chair, I will probably be 10 or 15 minutes so --

CHAIRMAN: Let's take our luncheon break and come back at quarter after 1:00.

MR. MACDOUGALL: Thank you very much.

(Recess - 12:00 p.m. - 1:15 p.m.)

CHAIRMAN: Go ahead, Mr. MacDougall.

MR. MACDOUGALL: Thank you, Mr. Chair. I think a break is always useful for reducing questions and I have taken that opportunity, so I shouldn't be very long.

Q.240 - Mr. Knecht, if I could get you now to go again to your IR responses which is exhibit PI-3 and again it's a response to EGNB and it's PI EGNB IR-13B.

A. Yes, sir.

Q.241 - And here in response to 13B you make the statement, I do not advocate the use of PPA billing determinants as cost causative factors for Disco, correct?

A. Yes, sir.

Q.242 - Now in the study you proposed have you changed the classification of export credits from the manner in which

Disco classifies export credits?

A. I did not in the study that I developed for the purpose of this proceeding because I was simply adopting the methodology that had been approved in 1992.

Q.243 - Okay. Are you aware that Mr. Larlee's only stated justification for classifying the export credits as 100 percent demand is because this is how they are charged through the PPA?

A. My understanding was that he did it that way to be consistent with the allocation of generation costs, with the plant costs were -- with the way -- with the way the plant costs come through on generation.

Now that may be the same thing as you are asking me which is because Genco classified -- Disco classified the Genco plant costs fixed variable, that he was being consistent in his treatment of the credit and in the allocation of costs.

Q.244 - Well maybe just to get clarity on it, if we could go and there is just -- it's just one IR we have to pull up. I apologize I don't have the exhibit number but I think we can find it quickly. It's Disco's response to CME IR-1, and I believe, Mr. Chair, it's in A-11, but if you bear with me one second I will confirm that.

Yes. Exhibit A-11, Disco CME IR-1. A-11, Mr. Knecht.

It's responses to interrogatories, July 14, 2005, volume 1 of 2.

A. Which interrogatory?

Q.245 - CME-1. It's the very first interrogatory in the book. And here there is a reference to the direct evidence of Mr. Larlee. The question was, under classification line 25, please explain why no portion of the Genco third party credit has been classified to energy.

And the response, Disco has contracted for all of Genco's capacity through it's PPA nomination. Disco does not use all the nominated capacity at all times throughout the year, enabling Genco to make third party sales using the available capacity. As a result the third party credits are used to reduce the capacity costs and have been classified at 100 percent demand.

And I guess what I'm asking you is did you understand as I had taken it, that Mr. Larlee was doing this because he was charging through the PPAs Genco at 100 percent demand, correct?

A. I think we are probably at a disagreement here without actually disagreeing, Mr. MacDougall. This was not the reference that I recall when I was responding to your question. And I guess my understanding was that Disco was trying to be consistent with its treatment of the credit and the treatment of the Genco fixed charges.

Q.246 - And their treatment of the Genco fixed charges is charging it using the PPA billing determinants, correct?

A. Yes, sir.

Q.247 - But you do not advocate the use of the PPA billing determinants, correct?

A. In the study that I did, yes, I do not advocate the use of the billing determinants. However in looking at this export credit issue that I did not take on directly in my evidence, but if you look at it, I think you can make a very good case for being consistent between your treatment of the plant costs and the treatment of the export credits.

Q.248 - So would you agree that the export credits are an offset to Disco's fixed costs?

A. That's my understanding. We had asked -- there was a piece of the cross examination that Mr. Hyslop undertook with the Disco witnesses trying to ascertain what the demand to energy split that they were referring to when they split those costs into demand and energy pieces was. And I guess I never understood what that split really meant. And I think that my position would be that you need to be reasonably consistent with any of these issues where you have a -- where you are getting a revenue credit, that it ought to be matched up with the costs for which the credit is being applied.

Q.249 - Okay. And in your study you classify the fixed costs of Genco as 40 percent demand, 60 percent energy? Correct?

A. I did.

Q.250 - But you didn't do that for the export credit.

A. And I was simply following the methodology that was approved by the Board and --

Q.251 - But you haven't treated the two consistently?

A. I did not in my study. And -- but in fact, you know, I would make a good case that you ought try to do it consistently. And if you can match it up plant by plant with where the export sales are, then you can do it even more accurately if you are allocating the costs that way. But yes, you are correct.

Q.252 - Great. Thank you very much. Now are you aware that the Alberta market has moved to a competitive market for supply?

A. Yes.

Q.253 - And has Alberta ever used marginal cost analysis for the allocation of revenue distribution?

A. I would say that the people who are paying the prices in Alberta are paying the prices that reflect market

conditions. Whether or not that reflects marginal costs I
suppose we can debate, but --
Q.254 - No. I just want to ask is there any use of the
marginal cost analysis for allocating revenue distribution
in Alberta by the regulators?
A. Well I'm not quite sure what you mean by allocated revenue
distribution, but if we are talking about an allocation of
costs and who is paying market prices, if you are facing
the market prices then you pay the market prices.
Q.255 - I guess my question is my understanding is you
testified there and are you aware of the regulators ever
using a marginal cost analysis for the allocation of
revenue in Alberta? A marginal cost study.
A. I am not aware -- I do not recall any sort of sense in
which they did use a marginal cost analysis. However,
they did move to market pricing. And to the extent that
my recommendation here is adopted, that would be the
ideal, would be to use marginal costs as a proxy for the
market pricing.
Q.256 - Okay. Would it be your view that you should reject
the cost of service model just because it might be
complex?
A. I suppose we all have different definitions of what

complex is, but no, I would not reject a model because it's complex.

Q.257 - Thank you. Are there any utilities that you are aware of that have a marginal cost in North America of a thousand dollars a megawatt hour?

A. I don't think I could cite a specific circumstance. I mean, there may be cases in which a distribution utility needs to go out onto the market and procure some power in an emergency circumstance and could face prices that high. They may not be reflective of any particular unit's marginal cost but it may be reflective of a marginal cost faced by that distribution utility.

Q.258 - But the generators in those situations don't have marginal costs of a thousand dollars a megawatt hour, correct?

A. You would have to take that up with a generating expert. My understanding is that there are cases when -- that you juice the generator to run it up past the capacity that it's comfortable running at in periods of system emergency to get that much out of it, and those -- the cost of doing so, you know, is imposing a cost on that generator that's beyond just the fuel costs.

So that there is a marginal cost associated with stressing the generator to meet the emergency load or to

earn the high prices that you can earn by doing it.
Q.259 - Well that's exactly right. Let's get to the latter part. There is markets where there is -- Dr. Rosenberg was talking about markets that have caps of a thousand dollars a megawatt hour. Is it your understanding that they have caps in certain markets because sometimes the market price might get up to a thousand dollars a megawatt hour regardless of what the marginal cost of the generator actually is? It's not the marginal cost of the generator. It's either transmission congestion or the requirement that people need supply that may drive the prices, correct?
A. The -- at some point you get to the willingness to pay argument --
Q.260 - Yes.
A. -- and you ration with the price mechanism that may be above marginal cost or it may be related to the fact that all those generators are up there producing. Presumably if the price has gotten that high then it's in the interest of the supplier to incur those costs.
Q.261 - Sure.
A. But, you know, I will certainly agree that there are probably circumstances in which the capacity is exceeded and the willingness to pay is higher than the marginal

cost of the last unit, and therefore the prices rise very sharply.

And, you know, in markets where it's a single energy price market putting those rate caps on, putting a price cap in place like that, can be sending the wrong signal to generators because that may be the time when you need to be recovering some of your fixed costs particularly for peaking units.

Q.262 - But those caps aren't necessarily related to the marginal cost of that generator, correct?

A. The are not necessarily related, no.

MR. MACDOUGALL: Mr. Chair, those are all my questions. Mr. Knecht, thank you very much. Mr. Chair, just since I have the podium, there was one undertaking to Dr. Rosenberg last Friday and it was by Board staff. We are endeavouring to have that ready for tomorrow, so that hopefully Board staff witness will be able to see it before they are on the stand on Wednesday.

CHAIRMAN: Good. Thanks, Mr. MacDougall.

MR. MACDOUGALL: Thank you. Thank you, Mr. Knecht.

CHAIRMAN: Any questions of the witness from the Irving group? Mr. Booker?

MR. BOOKER: No, Mr. Chair.

CHAIRMAN: Thank you. And Rogers Cable?

MS. VAILLANCOURT: No, Mr. Chairman.

CHAIRMAN: Mr. Gorman?

MR. GORMAN: Mr. Chairman, the Municipal Utilities also have no questions for this witness.

CHAIRMAN: Would you clear the way for Mr. MacNutt?

MR. MACDOUGALL: I will clear the way for either one.

CHAIRMAN: Good for you, Mr. MacDougall. Just clear the way and move on.

CROSS EXAMINATION BY MR. MORRISON:

Q.263 - Good afternoon, Mr. Knecht.

A. Good afternoon.

Q.264 - I want to turn to a couple of matters that arose in the course of your questioning this morning. First, Mr. MacDougall was talking to you -- asked you about an IR response regarding updating of the Peaker Credit information to 2005/2006?

A. Yes, sir.

Q.265 - And Mr. MacDougall suggested that Dr. Rosenberg could only analyze information that he had available and you had answered you were painfully aware of that. Now, I just want to make clear that you are not implying that Disco was unresponsive to the 1,200 IRs that it received?

A. No. Yes, that's correct. I was not --

Q.266 - It was because of a lack of data, not an unwillingness to provide data, is that fair?

A. It was not only based only on this hearing, it's a history of representing intervenors in regulatory proceedings that led me to my flip response to --

Q.267 - You also were talking about the use of an example this morning about Pennslyvania, where the distribution company would go out and get a flat rate for a block of residential power, I believe was the example you used?

A. That's incorrect. They were going out and getting a slice of system for all customer classes.

Q.268 - That's fair. And if you were doing a cost allocation study for a distribution utility in Pennslyvania, who was going out and getting -- I assume by an RFP or through a power purchase agreement, this slice of energy, you would just look at the PPA costs. You wouldn't go back and look at what the generator is bidding in on that RFP, what their actual costs were, would you?

A. Well, that's not quite correct. And to illustrate this, I work with an advocacy group called the Office for Small Business Advocate in Pennslyvania. And because the small business customers -- I know it will shock you -- in Pennslyvania tend to over-recover costs in their rates, as well as they do in New Brunswick, the advocate is very concerned about the rate design aspects of these things and has advocated fairly strongly that when utilities go out to purchase power, that they do it on a rate class basis, just what you suggest at the beginning, which is to go out for the small business class and to shop for it that way. So that that's the preferred approach, which is then at least on a rate class basis, we have allocated the cost consistent with what the market prices were. If I were called upon to take a flat per megawatt hour price that applies to residential, commercial and industrial rate classes in Pennslyvania, I would say let's go look at what we can simulate for what market prices are going to look like in this market and apply the load profiles of each rate class and allocate that way.

Q.269 - But if you were doing a Cost of Service Allocation Study for the distribution utility, you would be looking at the costs that are being charged to that distribution utility, correct?

A. And that's where I am disagreeing with you. I would try to pierce back and use the load profiles of each of the individual rate classes and apply that to market prices in the test period and thereby get different rates for each class that are reflective of what that class would face if it went out by itself to purchase that power.

Q.270 - In Pennslyvania, would those costs be passed through to the customer?

A. There is then the second step, which you would need to do if you could say then the generation costs we have figured it out on a market basis for the small business customers in Pennslyvania, the price is $70 a megawatt hour. We now need to design rates within the class. And the costs, to answer your question, would be passed through that way, yes.

Q.271 - Well, what I am trying to get at, Mr. Knecht, is that those costs are passed through -- through the distribution utility to the customer and the customer gets it -- these are passed on its bill, what relevance is there to the customer as to what the underlying generation costs are?

A. The relevance to the customer is the customer is now paying and each class will have a different average rate that needs to be recovered from that customer and therefore the price signal to each customer that is taking service from the distribution utility will be that price. And you have to do it that way, because if you don't, what will happen is you will set that flat price for all of the rate classes and the industrial guys -- the high load factor guys will go buy in the market.

So that if you don't set the rate, the prices that reflect what we are talking about here, which is the underlying generation economics and what we are talking about there, which is the underlying market prices by -- on an hourly basis, you will then be creating a distortion and causing customers to inefficiently jump out of the supply from the distribution utility and take market service.

Q.272 - How are they actually priced now in Pennslyvania?

A. In -- what happened with restructuring in Pennslyvania was they imposed a rate cap during a restructuring period so that all the rates were frozen based on allocated costs as of the time when they switched into restructuring. And now those utilities are gradually coming out of the rate cap process and started to go out for bid for these things and this issue is still being debated in Pennslyvania now, because the rate cap hearing is phasing out at different times for different companies there. And, you know, this is an issue that will be wrestled with.

Q.273 - So where it has been phased out -- no, I am going to leave that there for now, Mr. Knecht.

Now, Mr. Hyslop brought you to the issue of the cost classification for the distribution plant. Do you recall that this morning?

A. Yes, sir.

Q.274 - And you said that 36 percent of the non-heat residential customer cost was not related to generation?

A. Nor transmission.

Q.275 - And you were -- I believe the point you were trying to make is that it wasn't an insignificant portion of the revenue requirement. Correct?

A. Yes.

Q.276 - And what you are trying to say that -- if I understand it -- because 36 percent of this, if I understand your evidence correctly, was subject to some type of distribution plant cost, cost classification. Correct?

A. Well what I said was the 36 percent of the costs for the non-electric heat customers, the non-electric heat residential customers were not generation or transmission. It was all in the distribution revenue requirement, which includes plant costs and a variety of overhead costs.

Q.277 - That's my point. Not all of the cost that you are talking about would be plant costs, would they? There would be customer account and meter reading and customer service billing, et cetera. Those types of costs would be involved in that as well?

A. Yes, sir.

Q.278 - Now also this morning I think you said at some point

that how Disco purchases power through the PPAs -- I am sorry -- now Disc purchases power through the PPAs, and these are my notes, so you will forgive me if they are not quite verbatim, and that is a change we might want to recognize.
Is that something you said this morning?
A. Yes.
Q.279 - And then you went on to say that the PPAs should not be used because the PPAs billing determinants do not reflect underlying costs. And I believe you may have had that discussion with Mr. MacDougall again, just a few moments ago?
A. I think I said they don't reflect underlying cost causation, because the billing determinants are not the same as cost causation.
Q.280 - And I would like you to turn to your evidence, Mr. Knecht, which is PI-1, and if you to turn to page 13.
A. It's the PI-2.
Q.281 - Sorry. PI-2. Starting at the very bottom of page 13 at line 24 and going over to top of page 14, it says, what are the advantages and disadvantages of the PPA causation approach? And your answer to that and your evidence states, the primary advantage of this approach is that it reflects cost causation as currently experienced by Disco, as such it is the purest reflection of current cost

causation principles. Do you see that?

A. Yes, sir. That was the statement I referred to in my opening statement as a rather bold statement or brave statement.

Q.282 - So you are retreating from that statement, are you, Mr. Knecht?

A. Well, I believe I did in response to the first interrogatory from the Public Utilities Board. When I looked at this, I was looking at it the same way I think Disco was, which I think in the short run, and you know, in the very short run, that's what looks like from Disco's perspective the cost causation is.

But that's - it's simply not correct. It doesn't reflect the underlying cost causation and, therefore, doesn't reflect the capital substitution, capital for fuel or fuel for capital substitutions. And yes, in fact to the extent this statement is true, it's only true in a very narrow short term sense.

Q.283 - But you would agree with me, Mr. Knecht, that what drives Disco's revenue requirement is the PPA pricing. Correct?

A. And -- yes, I would agree. And I would add to that what drives the amount that they get charged in the PPAs is all of the underlying cost causation factors. You know, I understand when Genco figures out its costs, it's going to, you know, look at its resource mix and add those all up and that's the cost that is going to flow into the power purchase agreement and must be recovered from Disco.

Q.284 - And I want to pick up on something you said just a moment ago, but from Disco's perspective, the PPA prices are cost causative, correct?

A. Yes, but not from the -- not from the perspective of the signals that you want to send to your customers.

Q.285 - Now this morning, Mr. MacDougall led you to the point where I believe you said that the PPAs do not reflect Genco's marginal cost? I think you said that? I think that's what we are talking about right now?

A. Yes, sir. Yes, sir. I think that's correct.

Q.286 - And I think the implication, and correct me if I am wrong, of the question was that the PPAs have little value for ratemaking purposes. Now would you agree with me that the PPAs do reflect Disco's revenue requirement for generation costs? I think that's what we just talked about?

A. In a total cost basis, yes. That's what drives the total cost requirement that Disco's ratepayers need to pay. But we are not talking about the total revenue requirement. We are talking about how you allocate that to each of the classes --

Q.287 - No, no, I understand it.

A. Fine.

Q.288 - And I think it's both you in your evidence and Dr. Rosenberg pointed out last week that any marginal costs coming out of a marginal cost study, have to be reconciled to Disco's revenue requirement. Correct?

A. Yes, sir..

Q.289 - And there is a number of what Dr. Rosenberg described as fairly complex methods for doing that?

A. Yes.

Q.290 - And you would have to look to the PPAs in order to do that. Correct?

A. No. You only need to know what the total cost number is to balance to that. You may need to know a number of other factors depending on which methodology you use for adjusting the marginal cost signals back to average cost signals But the only thing you are reconciling to is the total revenue requirement.

Q.291 - And the total revenue requirement is contained in the PPAs. Correct?

A. Yes, but the PPAs could be structured any way and that revenue requirement would stay the same. So you have to --

Q.292 - So you have to -- in order to reconcile the revenue requirement to the marginal cost outcomes, you have to look at that PPAs?

A. I have to look at the PPAs, but I don't have to look at the specific billing determinants of them or use them to allocate costs in any way. All I am figuring out is what the total cost is that I need to normalize to.

Q.293 - But that wasn't my question, Mr. Knecht. My question was you have to look at the PPAs in order to do the reconciliation between revenue requirement and marginal cost?

A. Yes, you have to look at the total costs that flow through the PPAs to figure out what the total revenue requirement is for distribution utility.

Q.294 - Thank you. Now Mr. Knecht, I would like to turn to page 6 of your evidence. And beginning at lines 18 and again we are talking about generation costs here. It says "For a distribution utility such as Disco, generation costs represent the costs paid by the utility to purchase power on behalf of its sales customers (those customers who choose not to shop for power) and transmission costs are costs paid by the utility to a transmission utility or regional transmission operator typically based on a regulated tariff. Distribution and customer service costs continue to be incurred by the utility and are functionalized based on the utility's systems of accounts."

Now in that quote you say for a distribution utility such as Disco. But is it fair to say that this statement applies to Disco in this case?

A. I think it generally applies. There are limitations on customers' ability to shop for power. If that is what you are referring to, I believe I referenced that in my evidence.

Q.295 - No, I actually wasn't referring to that. It's just that your statement -- you said for a distribution utility such as Disco and I wanted to make it clear that the statement would apply to Disco.

A. I think it would generally apply to Disco. There are certain things that are specific to Disco but --

Q.296 - And Disco is the Applicant in this case, of course, Mr. Knecht?

A. Yes.

Q.297 - And by virtue of restructuring, would you agree that NB Power has been functionally unbundled as among generation, transmission and distribution?

A. I think that is certainly true in an organizational sense.

Q.298 - Okay. Disco purchases power under the PPAs, correct?

A. That's my understanding.

Q.299 - And it purchases transmission through the OATT, correct?

A. Yes, sir.

Q.300 - So generation and transmission functions are separated and by virtue of restructuring are functionalized, correct?

A. Yes.

Q.301 - Now I want to turn to page 7 of your evidence, Mr. Knecht. And I have just been having a little difficulty reconciling a statement that you make in there. And it is at page 7, lines 9 and 10.

And you say there "It is important to recognize that an embedded cost of service study almost never assumes that costs are fixed."

And then if I turn to page 9, and we go to line 11 through 15, you say "Base load capacity is typically provided by high fixed cost, low variable cost technologies." And then you go on to say a number of other things.

I am having difficulty reconciling those two statements. I am trying to understand what it is you are saying.

A. That is a fair question. The idea of an embedded cost study is when you allocate something on the basis of peak demand, you assume that over the long run, that cost varies with peak demand. And when you allocate something on the basis of number of customers, you assume that over the longterm those costs are going to vary with the number of customers.

And therefore, from the perspective of the embedded cost study, it is treating all of those costs as at least not fixed or they are long run variable. And I actually have a note in my evidence here is that what I should have said is "It is important to recognize that an embedded cost of service study almost never assumes that costs are fixed in the long run."

Q.302 - Okay. That is the point --

A. Then when I get on to the next page is to -- why I use high fixed costs, you know, these are fixed in the shorter term.

Q.303 - And in this case we are looking at an embedded cost study for a period of one year, correct?

A. The study applies to the costs in one year, yes.

Q.304 - So their --

A. Any cost allocation study is going to recognize long run implications in costs, particularly in embedded cost study. That is the principle of allocating things on that basis.

Q.305 - But in the short run you would say that you would agree with me that there are fixed costs in the embedded cost study. Correct?

A. Yes. Except that the basis for allocating those costs is that over the long term they vary with one of the parameters that we use for allocated costs.

Q.306 - And with respect to that evidence, the evidence that we just referred to, is it fair to say that the Board approved methodology classifies some fixed costs as energy related?

A. Yes.

Q.307 - And you have had some experience in this field, Mr. Knecht. And you would agree with me that many analysts, or some at least, when faced with the need to classify fixed generation related costs, have used methodologies that classify some of these fixed costs as demand related and some as energy related?

A. Certainly we have the experience in New Brunswick.

Q.308 - But that has been your experience?

A. Yes.

Q.309 - I want to turn to page 10 of your evidence. If you look at -- turn to line 20, 20 and 22. It says "Thus ideally the role of a distribution utility that procures electricity on behalf of its customers is to simply pass those market prices through."

And of course you start out with "one of the objectives of restructuring is to replace regulated generation with a competitive market."

So ideally if New Brunswick was a competitive market, the price paid by Disco through its PPAs would simply be passed through to its customers?

A. It would be passed through in one of a couple of different ways. For large industrial customers, you could simply pass it through as an hourly price. And then that would give the large industrial customers the opportunity to shop or perhaps do some hedging in the financial markets to control their costs.

For the smaller customer, for the retail customers, passing it through on an hourly basis is probably not cost effective. But nevertheless, the distribution utility should make some effort to recognize as much of the market prices and the market price signals in both its allocation of costs and its rate design as it possibly can.

Q.310 - So the point being, Mr. Knecht, that in a competitive market, the PPA prices would simply be passed through in one form or another, correct?

A. I didn't say the PPA prices. What I said was the market prices and market prices for electricity by necessity vary from -- vary over a very short period of time.

Q.311 - And in a competitive market there might be a number of generators providing power to Disco and one would assume that the prices in the PPAs therefore would be market prices?

A. For any particular type of load that Disco was buying, the price would reflect the market price for the hours that that unit was providing service?

Q.312 - That would be the point of having a competitive market, correct?

A. Well there are many points to having a competitive market but if you have a generator that is supplying energy, remember, it's the structure of the PPA between the distribution utility and the generator is going to reflect the desires of those two parties.

The overall costs for the overall period is some reflection of the market price for that period. But it would be difficult if you had a generator that was, you know, providing capacity at a 90 percent capacity factor over the course of the year, to then say -- and providing it at a fixed cost per megawatt hour over that period to say that that reflects the market prices in each of those hours, because it doesn't.

One of the advantages of having a competitive market is you will have a spot market where you can observe at least the energy component of price on an hour to hour basis.

Q.313 - I assume that you have read the evidence filed on behalf of Disco in this matter?

A. Yes.

Q.314 - And particularly the evidence of Sharon MacFarlane? Did you read --

A. Some time ago I think.

Q.315 - And you would agree with me that Ms. MacFarlane's -- in Ms. MacFarlane's evidence she says that one of the goals of restructuring NB Power is to move toward a competitive electric power market. Do you recall that?

A. I don't recall it but I will certainly accept your characterization of it.

Q.316 - I want to get into now, Mr. Knecht, the classification and distribution components. And again, it is at page 10, and it starts at line 9. And you say "It is often but not universally acknowledged that these assets must be built to attach all customers to the grid and that therefore, the costs contain a customer component." Do you see that?

A. Yes.

Q.317 - And so based on this evidence, do you support the notion that there is a customer component of the distribution system?

A. I do. It's difficult to prove with certainty that there is a customer component but kind of common sense in the little example I gave earlier suggests that there is -- that there should be a customer component.

Q.318 - And I believe your cost classification calculates a customer component, doesn't it?

A. It does.

Q.319 - If you could turn to page 32, please, Mr. Knecht? If you look at lines 24 to 28, and the question was put to you do you agree with Disco's proposed classification of protective and equipment costs? And your evidence says that Disco has no particular cost causation basis for classifying these costs. In the absence of any analysis, I suggest classifying these costs using the same proportion as all other distribution equipment. Correct?

A. Yes, sir.

Q.320 - And that's what you did. Correct?

A. Yes.

Q.321 - Now just as a matter of clarification, you don't have any cost causation analysis or basis for the

classification of protective equipment that you chose either, do you?
A. No, sir. One of the things that is fairly common in cost allocation studies is when you get a compound of these costs that you don't have a cost causation and direct -- a direct way of evaluating --
Q.322 - So you have to use judgment, correct?
A. You use your judgment and -- but you also a lot of times they will use the way everything else is classified within the cost allocation study and that's the method I followed. As I understood what Disco had done, is they simply left if at 50-50, which was the approved methodology.
Q.323 - So Disco's approach of using the Board approved classification is no more or less judgmental than your approach, is it?
A. I don't think so. I think mine is a little -- is a little more consistent with how cost allocation studies usually work, but yes, neither of us has done any analysis to say this is the right way to classify these costs.
Q.324 - So to be fair, Mr. Knecht, it's your best judgment?
A. Yes, sir.
Q.325 - And I think as Mr. MacDougall pointed out, not everybody is going to agree with your judgment or our

judgment or Dr. Rosenberg's judgment. Correct?
A. Hard to argue with that.
Q.326 - Now if we can turn to page 12 of your evidence and Mr. MacDougall brought you to this quote this morning that I am going to zero in and perhaps the smaller portion of that quote, at page 9 and 10 -- sorry, lines 9 and 10, it says while the company has been organizationally unbundled, generation planning continues to be done on an integrated basis. Can you provide me with the basis for that statement, Mr. Knecht?
A. No. As I sit here, no. I was rereading it this morning when Mr. MacDougall brought me through it. That was my understanding. And it was gained by, you know, having gone through the evidence and the interrogatory responses, but I am not sure I could put --
Q.327 - There is no evidentiary foundation for that statement, is there?
A. It is my understanding from reviewing that evidence that that's what it is. But I don't believe that I could put a specific reference on that as I sit here.
Q.328 - So this is an impression that you informed after reviewing all of the evidence?
A. Yes, I think so. And also -- yes, that's certainly the impression that I got from reviewing --

Q.329 - So if I were to tell you that generation planning is not done on an integrated basis, you would not have any reason to quarrel with that, would you?
MR. HYSLOP: I don't know if there is an evidentiary basis for the question Mr. Morrison just put. I don't recall anywhere in the evidence where that particular statement was made, Mr. Chair?
MR. MORRISON: I am not implying that it was, Mr. Chairman. What I am trying to get this witness to admit, quite frankly, is that he has no evidentiary basis for the statement that generation planning continues to be done on an integrated basis?
CHAIRMAN: I think he has already done that, Mr. Morrison.
MR. MORRISON: Thank you, Mr. Chairman.
Q.330 - Now, Mr. Knecht, if I could turn to page 12 of your evidence, and it's lines -- it's right at the top of the page actually. And it says regarding transmission costs, it's my current understanding that Disco's classification and allocation scheme is reasonably consistent with cost causation under the OATT and, therefore, I do not address this issue at this time.
Do I take it from that, Mr. Knecht, that you believe that Disco's approach for the dealing with transmission costs is reasonable?

A. Yes, I think I said that in my opening statement this morning.

Q.331 - Thank you. Yes, I believe you did. Now if we could turn to page 34. And I am getting into the area now, Mr. Knecht, of miscellaneous revenue. And if we look at lines -- well basically it's section 2.4, it's that whole section, and if I understand your approach to allocating miscellaneous revenue, is that you propose to allocate all the miscellaneous revenue on the same basis as the pole plant cost, is that correct?

A. That is the calculation that I did in the cost of service study that is in my evidence, because my only specific knowledge about what the miscellaneous revenue was was it related to poles -- to credit for poles.

I -- as a conceptual matter, and I believe you asked me an interrogatory on this question, as a conceptual matter, you ought to break up the miscellaneous revenue into each of its pieces and allocate them separately to the extent any of them are cost credits, such as the poles' costs, they should be allocated on the same basis as the costs are charged in the cost allocation study. And I think that was the conceptual point here, rather than the specific numerical calculations.

Q.332 - So it is fair for me to say then -- and I believe you do say, however, at least some of these revenues are related to revenues received from Aliant for maintaining poles owned by Aliant. Is it fair for me to say that you took that and extrapolated that to all of the miscellaneous revenue costs?

A. Yes, that's correct. And I wouldn't -- I wouldn't say you should do that. I mean, you should look at what each of those pieces are and what are allocated on a cost causation basis and if it's a credit to costs that are being allocated, you have to be consistent.

Q.333 - So -- no, that's fair enough. Even if -- now let me put this to you, Mr. Knecht, even if all the revenue was pole related, would you agree that there is not necessarily a cost causation there?

A. Well, if Disco is providing pole -- pole maintenance for Aliant and these are maintenance costs that are in its revenue requirement and the cost allocation piece is allocating those maintenance costs to each of the rate classes, then to the extent a credit is coming back, it's like a cost offset and the cost offset should be allocated the same way as the costs are.

Another way of handling that would simply be to take those revenues out of the maintenance costs for the poles and you would get the same result as what I am proposing.

Q.334 - I guess the problem I have is making the connection between Disco going out and doing services for Aliant. It's not going to make the cost of a pole any cheaper, right? These revenues are really gravy, right?

A. I -- I suppose if you can say that the maintenance can be performed for free and there is no cost associated with it and it is just -- I don't know, I am struggling with it. I am struggling with the hypothetical here of --

Q.335 - No, well it's not a hypothetical actually, a chunk of it says revenue comes from services that Disco provides to Aliant?

A. But if Disco is incurring a cost for them, it's in its revenue requirement then therefore --

Q.336 - It may not have nothing to do with poles?

A. If that's true then you are to allocate the revenue on the same basis -- methodologically you are to allocate the revenue on the same basis as the cost to which it applies. That's the --

Q.337 - I am not going to --

A. -- conceptual point I am making here.

Q.338 - -- I am not going to spend a lot more time on that, Mr. Knecht. I do have a comment -- or I would like to ask you a question with respect to a statement you make on page 39 of your report?

A. Yes, sir.

Q.339 - And it's at line -- well starting at line 10 really. It says, while regulators reasonably want to avoid causing plant shutdowns to the detriment of all ratepayers, it is almost impossible to determine whether any particular rate increase will have this effect. Absent an imminent threat of plant closure, it is difficult to justify providing -- this is the part -- substantial cross subsidies to large industrial customers. But by the time the plant shutdown becomes imminent rate relief is unlikely to make any difference.

Now is the cross subsidy that you are talking about here, and you are implying that there is a significant cross subsidy to the large industrial class, is that correct?

A. I don't know that I am implying that. It's a fairly generic paragraph. But the definition of cross subsidy that I have used in this evidence, which is consistent with how it is usually used in cost allocation and rate design proceedings is that a customer class that is receiving a cross subsidy is a class that has a revenue cost ratio below 1 and a customer class that is providing a cross subsidy has a revenue cost ratio in excess of 1. And that's what I am referring to here.

Particularly, for the large industrial customers where it is relatively unusual to see revenue cost ratios below 1. Basically --
Q.340 - Actually, Mr. Knecht, that's exactly where I was going with this. Your definition of cross subsidization revolves around the concept of unity. Correct? A 1 to 1 revenue to cost ratio?
A. Yes, sir. I believe that that is common practice.
Q.341 - And I think you -- were you here when Dr. Rosenberg testified?
A. Half of it.
Q.342 - Were you there for the half where Dr. Rosenberg outlined the -- well basically what he said is that no cost of service study is perfect. And would you agree with that?
A. Yes.
Q.343 - And because of this imperfection, there is no absolute way to determine absolute unity, would you agree with that statement?
A. Dr. Rosenberg's position I am sure will speak for itself.
Q.344 - My recognition is that there is no cost allocation study is perfect. There is uncertainty around any cost allocation estimate. And that is one of the reasons that

is often cited for having a range of reasonableness around a cost allocation estimate. Other reasons for having a range around the cost allocation is to effect other policy considerations that might want to be applied that are unrelated to the cost allocation uncertainty.

My personal view is the more uncertain a cost allocation study is, in some ways, you have even a greater desire to set the rates closer to 1, because then you have minimized your possible error.

Q.345 - That's assuming that 1 is capable of being determined with certainty?

A. Right. But if in fact a class -- if in fact you have a very wide range and what you want to do is minimize your chance that you are very far away from the allocated costs and, therefore, you push things fairly close together.

Q.346 - Okay. The range of reasonableness, you are aware that this Board as adopted a range of reasonableness of 95 to 105?

A. Yes, sir.

Q.347 - You are aware of that? And in your experience, is that unusual or unreasonable for regulators to do that?

A. That is reasonably common in Canada outside of Quebec.

Q.348 - Okay. Thank you.

CHAIRMAN: Mr. Morrison, sorry to interrupt. How much more --

MR. MORRISON: I would say I am going to be a good 20 minutes.

CHAIRMAN: We will take a 10-minute recess then, because I know Mr. MacNutt will ask for the evening break.

(Recess - 2:15 p.m. - 2:25 p.m.)

CHAIRMAN: Go ahead, Mr. Morrison.

MR. MORRISON: Thank you, Mr. Chairman.

Q.349 - Mr. Knecht, I would ask you -- this is the only time I am going to ask you to refer to anything other than your evidence. But it is PUB-1.

CHAIRMAN: In exhibit?

MR. MORRISON: Exhibit PUB-1. Sorry. Yes, PUB-1, the evidence of Energy Advisers. Pages -- beginning on page 52.

Q.350 - Do you see that, Mr. Knecht?

A. Yes, sir, I believe I have it.

Q.351 - Okay. Between pages 52 and 54, Energy Advisers outline some of the difficulties with the marginal cost study. Is that correct?

A. Give me a minute, Mr. Morrison, so I can review this briefly. Yes, sir, I think that is a fair characterization of --

Q.352 - ANd you would agree that what they are identifying here are issues that need to be resolved in order to translate a marginal cost analysis -- a theoretical marginal cost analysis into practice. Is that fair?

A. Yes, I think that's just the paragraph on page 52 going into page 53.

Q.353 - Okay. And I think I may have mentioned this to you earlier, if I didn't I meant to, I believe even you in your evidence, suggest that when you do a marginal cost analysis regardless of if you overcome these theoretical difficulties, you still are left with the problem of reconciling the marginal cost to the revenue requirements, correct?

A. Yes.

Q.354 - Okay. Now if we go back to your evidence, Mr. Knecht, and I am looking now at page 54, and I believe that is in the recommendation section of your evidence.

I just don't understand what your recommendation means.

In the last sentence, you say that the traditional methodology is not unreasonable but that Disco should take steps necessary to move in the direction of market pricing.

Now I just want to be clear as to what you are recommending here. Are you recommending here that Disco use the 1992 Board approved methodology, the traditional approach? Or are you suggesting that Disco move to some other methodology?

A. For the purposes of this proceedings I thought that the approved methodology was adequate. And that if the Board wanted to -- so yes, the answer to your question is yes, I am recommending that that be approved for the purposes of this proceeding.

Q.355 - Now on a go-forward basis, using the traditional method for classification would assume that Disco would be privy to the necessary fixed and variable cost information from generating resources, wouldn't it?

A. To go forward with methodology as it is currently approved, yes, it would need to run the Equivalent Peaker, you would need to know the underlying cost information. And as we discussed with Mr. MacDougall this morning, it would be best to have that as updated as possible relative to the test year.

Q.356 - But you couldn't apply this traditional approach if Disco didn't have access to the particular resource information, could it?

A. That's correct.

Q.357 - And I believe sort of a theme of your evidence, Mr. Knecht, is that Disco should move -- what you are recommending generally on a go forward basis, that we move to some type of market pricing approach, correct?

A. Again, I think that is a decision for the Board. If the Board decides from a policy perspective that they want to move in that direction, then -- and to reflect the restructuring and to start thinking about moving in that direction, then yes, then I would agree.

But my evidence is basically I would leave that to the Board. That is a policy call.

Q.358 - Assuming that the Board did take the view that it should move toward some market -- move toward a market pricing mechanism, would you agree with me if I said -- if I put to you the proposition that the PPA causation approach represents a movement in the direction of market pricing?

A. No.

Q.359 - What method -- you are aware that Disco has entered into a contract with Eastern Wind for wind power?

A. I understand that to be true. I don't know -- I don't know the specifics.

Q.360 - Now what method would you apply to the wind contract?

A. Again, if you move to market based pricing, you will be setting the -- you will be allocating the cost of service based on the marginal cost of any particular unit at any particular hour to the classes that are consuming power in that hour. To the extent wind is being dispatched during that hour, it's an interesting fact, but it's not going to affect the marginal cost, because the marginal cost of doing that is zero. The price in that hour when the wind is being dispatched, the marginal cost in that hour is going to reflect the marginal cost of some other unit. So that in a marginal cost analysis or in a market price analysis, you don't need to know what the -- you don't need to assign a price to the wind unit. It's going to be the first in the dispatch --

Q.361 - Right. But assuming -- let's say that you -- you couldn't apply the traditional approach to the wind contract could you, because Disco knows nothing about Eastern Wind's generation costs. Correct?

A. I believe -- I think that wind would pose a challenge. I haven't thought it through and I guess I would hesitate to be making recommendations about how I would classify the costs of wind power at least from the generator's perspective, it will certainly be short run fixed. And primarily short run fixed, you could apply it in the equivalent Peaker methodology from that perspective with the zero variable cost and just figure out how many hours it needs to operate to recover its -- to recover its energy.

So you might be able to apply it, but because of the intermittent nature of it, I would need to think it through a little bit more.

Q.362 - No, I guess the point I was trying to make, Mr. Knecht, is forget about marginal cost analysis for a moment. If you were to do a cost allocation study on the wind contract, you wouldn't be able to use the traditional approach, because Disco doesn't have any information as to what the generator's costs are, correct? Wouldn't you have to look at the price that comes through from -- in the wind to PPA as the cost driver?

A. Again I don't know that I necessarily would. I think you can certainly estimate the underlying cost nature of that kind of facility --

Q.363 - That's fine.

A. -- for doing cost allocation purposes. So, you know, if the prices come through on some basis that just don't look reasonable for allocating costs, then you may need to push further back and evaluate the -- and make an estimate of what the cost causation really looks like.

Q.364 - So you estimate it in that case?

A. Yes.

Q.365 - I want to turn to page 18 of your evidence. And at line 11 and 12 you say that Disco's approach did not produce unreasonable results. Is that right?

CHAIRMAN: What line, Mr. Morrison?

Q.366 - I'm sorry. It's at page 18, line 11 and 12.

CHAIRMAN: Thank you.

A. Yes, sir.

Q.367 - And you haven't changed your view with respect to that conclusion?

A. It's certainly not the cost allocation methodology that I recommend. And given the subjective nature of Disco's approach where some costs are subject to the 40/60 split and some costs are not, I guess it was sort of the arbitrary distinctions that made me -- you know, that made me concerned.

Depending on how you made those arbitrary distinctions, it would be possible to come up with a methodology that would be consistent with the underlying cost causation, but there is no way to tell by doing it that way. And I think that was the intent of my statement at this point.

Q.368 - And we know that you differ with respect to the methodology, but the fact remains that you have come to the conclusion that the results weren't unreasonable?

A. Well I said it may not be unreasonable depending on how you ended up doing it. As a matter of my evidence, I would recommend using a different study for the purposes of this proceeding.

Q.369 - No, I understand that, Mr. Knecht, and I think it is quite clear that various experts here are proposing to use different methodologies. But what your evidence says is that the results were not unreasonable. Correct?

A. I think what it says here is and in the sentence is that it says is that the (inaudible) approach is not that it necessarily produces unreasonable results. That is under some circumstances it might produce reasonable results but I don't think I testified that it is not unreasonable.

Q.370 - Okay. That is fair enough. Now we have talked about your recommendations on page 54. And basically one of the recommendations that you are putting forward is moving to a marginal cost approach or at least pursuing the notion of gathering more load research data to see whether a marginal cost approach is appropriate. Is that a fair characterization of your evidence?

A. Again, I think I would make that recommendation but again, I think it is a policy call for the Board.

Q.371 - Okay. And I am a little perplexed at that because when I look at page 17 of your evidence and I am looking at lines 15 to 17, it says "Thus overall my analysis suggests that the use of a marginal cost approach for allocating generation costs would not result in large differences between the cost per kilowatt hour for the various rate classes."

And I guess my question to you, Mr. Knecht, is if your analysis is showing no significant differences, why would you be making a recommendation to move to a marginal cost analysis?

A. My analysis is only based on the historical year for which I had that marginal cost information. And I don't think there would be any disagreement from the experts in this room that the nature of those marginal costs could change considerably as we move forward.

Certainly fuel prices are a lot different in 2005/2006 than they were in 2004/2005 and going on to 2006/2007 they may change further. The advantage of doing the analysis is you wanted the answer to that question.

My analysis was relatively narrow and applied only to 2004/2005.

Q.372 - Okay. That's fair enough. I just have a couple more questions for you, Mr. Knecht. This deals with some of your recommendations or comments with respect to load research.

And you are aware that Disco has a residential load research program for the residential piece, right?

A. Yes. I guess my understanding is it has been a little intermittent but that it has been reinvigorated.

Q.373 - And at page 2 of your evidence, and I don't think you need to turn that up, you basically are suggesting that more load research be done for the general service classes, correct?

A. Yes, sir.

Q.374 - And would you agree with me that such research would take more meters than the residential load research program due to the diversity of the class?

A. I am not a load research expert but that would not surprise me in having represented small businesses there is a lot more diversity of load within the general service class. Although the reference to farms and churches this morning may suggest that there is a fair amount of diversity in the residential classes as well. Particularly at the upper end. But generally I think I would agree that that would be a somewhat larger undertaking.

Q.375 - And the meters would have to have a demand component, would they not?

A. I think that is necessary to do load research.

Q.376 - And that would --

A. They would need to be interval meters, yes.

Q.377 - And that would mean they would be more expensive than the residential meters?

A. Yes.

Q.378 - And more meters means more data processing, correct?

A. Data processing has become I think relatively inexpensive. I would suspect the metering would be the major aspect of this recognizing that I am not an expert in that area.

Q.379 - And finally, Mr. Knecht, on page 12 of your evidence, you basically set out I think what you describe as three methodological constraints that are potentially useful in doing a cost allocation study for Disco. Correct?

A. Certainly the three I addressed in my threshold questions as to how we ought to tackle this problem.

Q.380 - And one of them is PPA causation, correct?

A. Yes.

MR. MORRISON: Thank you, Mr. Knecht, those are all my questions. Thank you, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Morrison. Before we break for the day, Mr. MacNutt, you were chatting with other counsel at the time the Board came in. And I think everybody in the room is aware that Mr. Garwood had an operation for appendicitis and you had a suggestion to me and I asked you to put it to counsel. What was the result of that?

MR. MACNUTT: I haven't had a chance to canvass counsel, Mr. Chairman. I did talk to Mr. Morrison and he apparently doesn't have any difficulty. But I didn't have a chance to talk to Mr. Hyslop --

CHAIRMAN: Can't hear you, Mr. MacNutt. But --

MR. MACNUTT: I haven't had a chance to talk to Mr. Hyslop, Mr. Gorman or Mr. MacDougall.

CHAIRMAN: Well all right, I will do it right now. Pretty basically is the suggestion was to have Mr. Garwood on standby on a telephone to hear the questions and respond to them.

Does anybody have any problem with that? In other words, speaker phone. We use that in the most recent Acadian Bus Lines matter that we had and it's okay if your equipment is good. There are some limitations but other than that. Mr. Hyslop?

MR. HYSLOP: I can't think why I would object so I will agree it seems like a sensible solution.

CHAIRMAN: Mr. Gorman?

MR. GORMAN: No objection.

CHAIRMAN: Mr. MacDougall?

MR. MACDOUGALL: No objection, Mr. Chair.

CHAIRMAN: So I take it that is everybody concurs. Would you ensure that Mr. Garwood has the bible at hand when he takes up the phone call and Mr. MacNutt, have you had an opportunity to speak to Disco to see if they can make arrangements to have a good speaker phone in this room?

MR. MORRISON: Well he has certainly spoken to me about the arrangements. Whether I can assure it will be a good speaker phone in the room is another story, Mr. Chairman, but we will do our best.

CHAIRMAN: Yes, okay. There are some of them that they don't cut off if somebody -- for instance, one of the difficulties that we have had with them of course if you get somebody that is longwinded on the other end of the line, why you can't break in.

MR. SOLLOWS: You want a duplex line, not a multiplexing line.

MR. MORRISON: There may be some advantages to that, Mr. Chairman.

CHAIRMAN: Okay. Well then we will break --

MR. MACDOUGALL: Mr. Chair --

CHAIRMAN: Pardon me?

MR. MACDOUGALL: Just one thing related to that, Mr. Chair. I know that we had set two days for Mr. Knecht and then two days for Mr. Adelberg and Garwood. Just to plan for cross examination, if we finish tomorrow with Mr. Knecht, which I am assuming we are, do we wait and then start Mr. Adelberg and Garwood Wednesday just so that we can do it appropriately to meet their schedules and our cross examination or was it your intention that we would then forge one?

CHAIRMAN: I would suggest that counsel get together after this and see what they come up with. My only concern is, you know, if we were to be able to complete everything tomorrow, which might be beyond the realm of possibility, that we do it. That's all. So I will leave it up to counsel and make a recommendation tomorrow morning.

MR. MACDOUGALL: Okay. Thank you, Mr. Chair.

CHAIRMAN: Thank you. We will break until 9:15 tomorrow morning.

(Adjourned)

Certified to be a true transcript of the proceedings of this hearing as recorded by me, to the best of my ability.

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