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

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INDEX

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BOARD STAFF:	Doug Goss
	John Lawton
	John Murphy
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CHAIRMAN: Good morning, ladies and gentlemen. May I have appearances please for the Applicant?

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

CHAIRMAN: Thanks, Mr. Morrison. Canadian Manufacturers and Exporters New Brunswick Division?

MR. PLANTE: Dave Plante appearing on behalf of CME New Brunswick.

CHAIRMAN: Thanks, Mr. Plante. Anybody here from Eastern Wind? No. Enbridge Gas New Brunswick?

MR. MACDOUGALL: Good morning, Mr. Chair. David MacDougall representing Enbridge Gas New Brunswick. And today I am joined by Ruth York of EGNB and John Thompson, Consultant to EGNB.

CHAIRMAN: Good. Thanks, Mr. MacDougall. The Irving Group? Jolly Farmer is not in the audience. Rogers Cable? Self-represented individuals? The Conservation Council is still an Intervenor and somehow got off my list. And Mr. Coon thought it was in Saint John this morning so he is now beetling up on 7.

And the young lady here is representing Conservation Council?

MS. MORRISSEY: Yes. Good morning. My name is Christa Morrissey and I am standing in for Mr. Coon until he does arrive.

CHAIRMAN: All right. Thanks, Ms. Morrissey. The Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman and Commissioners. Raymond Gorman appearing for the Municipal Utilities. This morning I am joined by Consultant, Paula Zarnett, and from Saint John Energy I have got Eric Marr, Dana Young and Jeff Garrett. And a little bit later this morning I will be joined by Charles Martin from Edmundston Energy and Dan Dionne from Perth-Andover Electric Light Commission. And I believe Mr. Richard Burpee will be here from Saint John Energy a little bit later as well.

CHAIRMAN: More importantly, is Mr. O'Rourke here? Oh sorry, Mr. O'Rourke is with the Public Intervenor. I was trying to find somebody who was missing that I could draw to your attention.

Vibrant Communities? And the Public Intervenor?

MR. HYSLOP: Good morning, Mr. Chairman. Peter Hyslop and I am joined by Mr. Barnett, Mr. O'Rourke and Ms. Power.

CHAIRMAN: Great. Thanks, Mr. Hyslop. And Mr. MacNutt, although you are not going to be playing a role today, or perhaps a passive one, who is with you today?

MR. MACNUTT: Mr. Chairman, I have with me Doug Goss, Senior Advisor, John Lawton, Advisor, and John Murphy, Consultant.

CHAIRMAN: Good. Thanks, Mr. MacNutt. I don't see any Informal Intervenors being represented, but if there are, why, hold up your hand and we will get you on the record.

MR. THOMPSON: Terry Thompson, Mr. Chair, of Terrence Thompson Consulting.

CHAIRMAN: Okay. Thank you. Any preliminary matters?

MR. MORRISON: Yes, Mr. Chairman, a few. First, as the Board is aware, the undertaking responses on the revenue requirement are due on Monday, November 14th at noon. I have spoken to most of the Intervenors and what we have done in the past is post them on the Internet, on the website noon, and we would have hard copies, binders available on Tuesday.

Again, I have spoken to most of the Intervenors. They don't seem to have a problem with it. Given the long weekend, quite frankly it is probably going to be impossible for us to have binders available by noon on Monday in any event.

So what we are proposing, with the Board's consent, is that the revenue requirement responses would be posted on November 14th at noon and a hard copy delivered on Tuesday, November 15th. We do have, you will recall, there were some IRs that were deferred from the CARD piece that were really revenue requirement, those will be available tomorrow on the website at noon and again, the binder will be delivered on Tuesday.

And with respect to the supplemental interrogatories, they are due on November 28th. Again, we would post those with the Board's permission, noon on the website and the binder delivered on the following day.

CHAIRMAN: And Mr. Morrison, as well on the 14th you were supposed to file an indication to the Intervenors any questions that you are not prepared to answer and as well reasons for those. That is all from memory.

MR. MORRISON: I believe it is the 17th, Mr. Chairman.

CHAIRMAN: Sorry, Mr. Hashey.

MR. HASHEY: No trouble. Sorry, there is a limited number of microphones. On the 17th what is going to happen is that the Intervenors who have any difficulty with the answers will give us notification. And we will then prepare a binder and appear on a Motions Day, which is on November 22nd.

So the 17th is the day that we get an indication if people are pressing us for information that we are not able to provide or are objecting to provide.

CHAIRMAN: Okay. What is the difficulty in simply also on the 14th saying we are not prepared to answer the following questions.

MR. HASHEY: Oh, no, we are going to do that on the 14th. And you will have the -- if there is something we can't answer we will say why we can't answer. We will be specific in that answer.

CHAIRMAN: Okay.

MR. HASHEY: Oh, no, that's all going to be done on the 14th.

CHAIRMAN: All right. That's what I was referring to.

MR. HASHEY: Sorry, I misunderstood.

CHAIRMAN: I misunderstood. Maybe I misspoke myself. Fine. Go ahead, Mr. Morrison.

MR. MORRISON: So that is what we are proposing, Mr. Chairman, with the Board's approval.

CHAIRMAN: Any parties any comments on that schedule? We will have to go with that, Mr. Morrison.

MR. MORRISON: Okay. Thank you, Mr. Chairman. There is an undertaking -- well it is actually -- it is an IR response really. You will recall that the Public Intervenor submitted an IR and asked for updated financial statements and an annual report, when they became available. They are now available so we would put that on the record as an exhibit, I believe, Mr. Chairman.

CHAIRMAN: Okay.

MR. MORRISON: And I think copies have been provided to the Secretary.

CHAIRMAN: Yes, she is busy stamping over there. That is a good indication. Those are the ones that -- those statements are due the first of July? Are those the ones?

MR. MORRISON: I believe they are.

CHAIRMAN: Yes. I can hardly wait to get to the rate hearing and find out how much you paid to have it printed. The government printer does it for under $1,200.

MR. MORRISON: Yes. I recall that from the SO hearing, Mr. Chairman. And we will have those available to all the parties at the break, Mr. Chairman. We are a little bit short on photocopiers at the moment.

CHAIRMAN: The Secretary informs me that we haven't used up number A-48. So the document -- well let me see. This is a response, Mr. Morrison, to Disco PI IR-31, August 19, 2005?

MR. MORRISON: That's correct, Mr. Chairman.

CHAIRMAN: Okay. So that will be exhibit A-48. Mr. Morrison, it came under cover and it has two parts to it, is that correct?

MR. MORRISON: That's correct.

CHAIRMAN: But they both form part of the response to that interrogatory?

MR. MORRISON: That's correct.

CHAIRMAN: Okay. That's good. Oh dear. That report cost more than $1,200. Anything else, Mr. Morrison?

MR. MORRISON: One final preliminary matter, Mr. Chairman. We do have our take-home exam completed and we are going to have that marked, at least I presume you would want to have it marked?

CHAIRMAN: Yes. I presume that's a response to Commissioner Sollows' question --

MR. MORRISON: That's correct.

CHAIRMAN: -- the take-home exam. That will be A-51.

MR. MACNUTT: Mr. Chairman, what is being marked as A-51? We have got a number of documents. I'm just trying to sort out which is being marked.

CHAIRMAN: It's the take-home exam, Mr. MacNutt. No. Seriously it's the problem or the question that resulted from Commissioner Sollows' questioning which was put to all the parties. This is Disco's response to that.

MR. MACNUTT: And it's being marked as A-51?

CHAIRMAN: That's correct. Anything else, Mr. Morrison?

MR. MORRISON: Those are all the preliminary matters, Mr. Chairman.

CHAIRMAN: Okay. Does anybody else have a response to the take-home exam as Mr. Morrison has indicated?

MR. GORMAN: We do not.

CHAIRMAN: I wonder if Mr. MacDougall does. Mr. MacDougall, we are talking about Commissioner Sollows' question.

MR. MACDOUGALL: Yes, Mr. Chairman. No, we do not have a response to that specific question. It was on transmission issues that were not particularly germane to the points we were raising. So we do not have a response to it.

CHAIRMAN: Any -- does anybody have a response? Mr. Hyslop?

MR. HYSLOP: We filed ours on Friday.

CHAIRMAN: That's right. Did we mark that?

MR. MACNUTT: Yes, Mr. Chair.

MR. HYSLOP: Yes. I believe it was PI-8, Mr. Chair.

CHAIRMAN: I can't remember what happened on Friday. Okay. Nothing else preliminary then. Anything preliminary from the Intervenors at all?

MR. MACNUTT: Mr. Chairman, just on marking exhibits, in the documents Disco just handed around is the 2004/2005 annual report. Has that been separately marked as an exhibit or is it within --

CHAIRMAN: You mean that shiny edition?

MR. MACNUTT: Pardon?

CHAIRMAN: You mean the shiny edition?

MR. MACNUTT: This?

CHAIRMAN: Yes. I think that's just the one for public consumption, but all the figures are in the exhibit that we marked, is that right, Mr. Morrison?

MR. MORRISON: That's my understanding.

MR. MACNUTT: Well I'm still confused.

CHAIRMAN: Well it's part of A-48, Mr. MacNutt, except this one is a glossy. It has been --

MR. MACNUTT: No. It's my understanding that this is Holdco, the bound package, and Disco forms part of Holdco.

CHAIRMAN: Mr. Morrison, help us out.

MR. MACNUTT: In other words, I assume the bound version here is the holding consolidated financial statements for Holdco and all its subsidiaries.

CHAIRMAN: Let's wait for Mr. Morrison to figure out what is going on here, Mr. MacNutt, and we know what the problem is.

MR. MACNUTT: Thank you, Mr. Chairman.

MR. MORRISON: It's -- there are two parts to the response. They are Disco's audited financial statements and the 2004/2005 annual report for the NB Power group. That's what -- so there is two documents that should form part of that exhibit.

MR. SOLLOWS: So this one goes to the end of March, this spring?

MR. MORRISON: That's correct.

MR. SOLLOWS: And this one only covers the six months from the break-up of the company to the spring?

MR. MORRISON: Yes.

MR. SOLLOWS: Okay. Thank you.

CHAIRMAN: So what we are saying, Mr. Morrison, is is

Holdco's bound annual report, is that included in exhibit A-48?

MR. MORRISON: Yes.

CHAIRMAN: All right, Mr. MacNutt? I suggest you caucus.

MR. MORRISON: The bound copy is the holding company and it consolidates the financial statements --

CHAIRMAN: Mr. MacNutt, Mr. Morrison just said that that's contained in exhibit A-48. Now I don't know. And Mr. Goss is shaking his head. We will take a minute. Mr. Morrison, would you go down to Board Staff and straighten this out.

(Brief Recess)

CHAIRMAN: Okay. We will mark it. By the way, I can't criticize the glossy because that is Holdco and Holdco can go to the market or whatever. However, I haven't seen your final Disco one yet. We will see that later, I presume.

MR. MORRISON: Yes.

CHAIRMAN: Okay, Mr. Morrison. What is the result?

MR. MORRISON: I think the consensus is it would be preferable to have the documents marked separately. A-48 is basically financial statements for the six months that Disco was in existence and the annual report is a report of -- for the entire fiscal year, and it has -- and it's segmented out on page 55.

So it has for each of the operating companies financial results for the entire fiscal year. I think Mr. -- I think the Board Staff would prefer if they were marked as separate documents.

CHAIRMAN: Well I think to satisfy them we will do that.

MR. MORRISON: Okay.

CHAIRMAN: So I think this is A-52. Okay. Now since we have got that straightened out anything else? Any of the parties? Okay. Mr. Morrison.

MR. MORRISON: Thank you, Mr. Chairman. Good morning again. Good morning, Commissioners.

CHAIRMAN: Could you give me your estimate of time?

MR. MORRISON: I'm -- it will be I am assuming about 40 minutes.

CHAIRMAN: Okay. Thank you.

MR. MORRISON: The challenge has been, Mr. Chairman, to parse this information into discrete issues and try to be as succinct as possible.

The Board in this hearing is faced with several broad topics to consider. And I guess I can list them. As Dr. Rosenberg put it, the threshold question is what costs are to be included in the cost of service study.

Other issues are the classification of those costs, particularly the fixed generation costs, allocation of revenues and costs, the issue of the marginal cost study, and I will be speaking briefly to some specific rate design issues.

Dealing with the first and threshold question which is what cost are to be included in the cost of service study. Before the Board can consider the classification of generation fixed costs, it must first address the threshold question of what costs are to be classified. Is it the PPA costs or is it the underlying generation accounting costs? Put succinctly, do you deal with the PPA costs or look through the PPAs to Genco's generation costs?

It is our submission that this Board must look at the PPA costs. First, in its decision regarding section 156, this Board acknowledged that the PPA costs are those which drive Disco's revenue requirement. Albeit the Board left open the option to examine underlying costs for ratemaking purposes, it nonetheless affirmed that Disco's cost causation comes through the PPAs.

Second, all parties have acknowledged that for cost allocation purposes one must adhere to the principles of cost causation. What drives Disco's costs are the PPAs. They are the cause of Disco's costs. There may be other factors driving Genco's costs, but from Disco's perspective, its costs derive directly and solely from the PPAs.

Now Energy Advisors agrees with Disco that PPA causation is the proper approach. And you will recall that I questioned Mr. Adelberg on this. And at page 2170 of the transcript I put the question, "And if we look at page 5 of your evidence at line 12 you say, generally speaking the company's approach of relying on billed costs appears reasonable. Is that a fair statement?" And his answer, "Yes".

Now Mr. Knecht on the other hand argues that you should look beyond the PPAs at the underlying generation accounting costs. In support of this he says that NB Power continues to function as an integrated utility. There is no competition. And NB Power continues to plan its generation requirements in a centralized manner. And you will recall under cross examination that Mr. Knecht admitted he didn't have any evidentiary basis for this latter assertion.

Now under section 80 of the Electricity Act, Disco is the entity that must seek new supply when it needs it and not some centralized entity. Mr. Knecht's view that NB Power is in practice an integrated utility is consistent with the view that Dr. Rosenberg took for rejecting PPA causation.

It is our submission that regardless of the fact that Mr. Knecht and Dr. Rosenberg perceive NB Power as a vertically integrated utility, at law it is not. Pursuant to sections 3 and 4 of the Electricity Act, NB Power was transformed from a vertically integrated utility into a holding company and four distinct corporate legal entities.

They were created by the Electricity Act but as all other business corporations in New Brunswick, they are governed by the Business Corporations Act and have the capacity, powers and privileges of an actual person. Also, the PUB has recognized that it does not regulate Genco or Nuclear Co.

So whether one likes the PPAs or not or agrees with restructuring or not, put frankly the government has spoken. It is our submission that in order for the Board to accept Dr. Rosenberg's and Mr. Knecht's study of underlying generation costs, it must reject the clear intention of the legislature and the legal realities of restructuring.

Disco submits that it is a stand-alone distribution company which secures its power supply through power purchase agreements such as the Genco PPA and the Eastern Wind contract. In that regard I suggest it is similar to the example I referred Dr. Rosenberg to, and that's found at page 1581 of the transcript.

The question I put to Dr. Rosenberg you will recall was with respect to the PGM system. The question was, "So if you were doing a cost allocation study for Delmarva or another strictly distribution company in the PGM system, you would be looking at their purchase power costs, correct, through their purchase power agreements?" And his answer was, "Well that's right. I mean they have what is called standard offer service. Correct. And the standard offer service is based without regard on an embedded cost study." And I pressed further and I said, "But their price driver would be their purchase power costs? Their price driver would be their purchase power costs, that's correct, for their standard supply or supply, yes."

Finally, any methodology for cost allocation we submit must be sustainable in the long run. Disco, as an independent distribution company, will not have access to generation accounting costs of generators, including Genco, on a go forward basis.

I believe all of the experts agreed that without this information, it is impossible to conduct and embedded cost study using anything but the PPA causation, and it's our submission that you can't do it other than using anything but the PPA causation approach.

Even in the course of this hearing, Disco was dependent on the co-operation of Genco in providing certain cost information. That co-operation may or may not be forthcoming as New Brunswick moves further towards an open market. As you are aware, Disco could not obtain accounting cost information from the non-utility generators.

In summary, PPA causation is the only approach which is consistent with the real and legal realities of restructuring and is sustainable in the long term.

So the next critical question is once you determine what costs you are going to look at, how do you classify those costs. And that goes to the issue of classification of the generation costs, which I would suggest has been the central focus of this hearing.

The methodology and rationale which Disco used in classification of the generation costs was described by Mr. Ketchum in his direct examination. First Disco looked at each PPA individually to evaluate how to treat them under restructuring.

The Genco PPA contains a fixed and variable component. Disco, using the PPA or cost causation principles, classified the costs between demand and energy as billed.

The Nuclearco PPA however is priced on a per kilowatt hour basis. However, it is really designed to recover a very significant amount of fixed costs.

Dr. Rosenberg supported this under cross examination. He addressed the fact that it is a take or pay contract, thus really fixed costs despite the kilowatt hour or energy basis for pricing. And that can be found at page 1500 of the transcript.

To reflect this the fuel component of the -- how Disco dealt with it, the fuel component of the nuclear PPA was separated out. And they knew the fuel component through the fuel auditing process. So the fuel component was separated out and the remainder was classified using the Board 40/60 demand energy split of fixed production costs.

Now much has been made of the apparent inconsistency in Disco's approach to the Nuclearco PPA. It is submitted that Disco was not inconsistent in its approach. It relied on the PPA as billed costs except where to do so would be patently unreasonable.

In that case it applied the Board 40/60 split to the fixed costs. There is apparently unanimous agreement that the major share of the Nuclearco contract is actually a fixed capacity cost.

And I will refer to Dr. Rosenberg's testimony and it appears at page 1571 of the transcript, and the question, "Do I take it from what you are saying that you believe that it would be inappropriate to ignore the fixed nature of the Nuclearco PPA for cost allocation and rate design purposes?" Answer, "I agree with that entirely."

Now besides Disco's approach, the Board has been provided with three other approaches for classifying the fixed generation costs.

First, Dr. Rosenberg prepared his study using the Peaker Credit Method. The fundamental reason he did so was his belief that the Board adopted the Peaker Credit Method in the 1992 CARD decision. And this was the method he believed that Disco used.

Essentially he alleged -- and I recall the exchange with him -- he alleged that Disco adopted the Peaker Credit Method, they didn't do it right. So he undertook to do it properly. That is the basis of his cost allocation study.

So his evidence is based on two assumptions. First, that the Board approved the Peaker Credit Method in its 1992 CARD decision. And secondly, that Disco applied the

Peaker Credit Method, albeit in his opinion improperly.

It is Disco's submission that neither of these assumptions is correct. First, it is clear from the evidence of Mr. Ketchum that Disco did not use the Peaker Credit Method but rather the Board approved 40/60 split.

Second, I would submit there is nothing in the 1992 CARD decision to indicate that the Board specifically approved the Peaker Credit Method. You will recall that Energy Advisors initially was under the misconception that the Board had adopted the Peaker Credit Method and they admitted their error after, in their words, hearing Disco's direct evidence.

The two assumptions upon which Dr. Rosenberg's Peaker Credit Analysis are based are not correct. It is submitted, therefore, that the Board should reject Dr. Rosenberg's study. Indeed Dr. Rosenberg admitted under cross examination that if the Board had not approved the Peaker Credit Method in 1992, he would have used the fixed variable approach. However, there is no fixed variable study before you.

Now the approach advocated by Mr. Knecht on behalf of the Public Intervenor is to use the underlying generation accounting costs and then apply the Board approved 40/60 split to all costs. Both the Nuclearco PPA and the Genco

PPA would be treated in exactly the same fashion.

Mr. Knecht, we submit, ignored the demand energy split in the Genco PPA. Disco argues that this is counter to cost causation principles and therefore Mr. Knecht's approach should also be rejected.

Finally, Energy Advisors accepts the PPA causation approach put forward by Disco but ignores the demand energy structure of the Genco PPA. Disco is subject to the costs of this PPA for the life of the heritage assets and it is submitted that the PPA costs reflects sustainable cost causation principles.

In summary, Disco submits that its approach to classification of the fixed generation costs recognizes the reality of restructuring, is internally consistent with the principles of cost causation and, as far as possible, reflects the Board's 1992 approved methodology where common sense and the nature of the cost and the contract dictate.

Now I would like to get into some of the allocation issues, and there have been several of them discussed.

First, the classification of the distribution costs. With respect to classification of distribution costs, by and large Disco applied the Board approved functionalization and classification methodology.

There have been improvements in Disco's accounting and data collection and this provided better information which permitted refinements to Disco's functionalization and classification factors. Where this better information was available, Disco applied this better information and developed a new split of the distribution facilities between primary and secondary and also new classifications between demand related and customer related costs.

Where no new information was available, Disco simply applied the traditional ratios approved by the Board in the 1992 CARD decision.

Now there appears to be little controversy over Disco's approach. Although Dr. Rosenberg did not specifically address the issue, he felt Disco's approach to functionalization and classification of distribution costs was not unreasonable. And that's found in the transcript at page 1590.

And Energy Advisors also concluded that Disco's approach was reasonable.

Only Mr. Knecht took issue with the classification of distribution costs. Mr. Knecht favours the zero intercept approach for poles and fixtures and conductors as well as for transformers. Disco used the minimum system approach for poles and conductors and the zero intercept approach for transformers to determine the customer and demand related costs of distribution.

We submit that Mr. Knecht substituted his judgment for the Board approved method for easements and projective equipment, whereas the company used the Board approved classifications. Mr. Knecht recommends that Disco be directed to prepare a study to enable it to develop zero intercept classification factors for additional elements of distribution costs.

You will recall that Mr. Ketchum's expert opinion was that Disco's approach was reasonable. Now given the relative magnitude of the distribution costs to Disco's overall revenue requirement, we would urge the Board to exercise restraint in directing additional research or placing additional research burdens on Disco simply to substitute one reasonable approach for another or to substitute one reasonable judgment for another.

I would like to move on to export credits, or sometimes in the course of this hearing referred to as third party credit benefits.

Now on this issue there is some controversy over the manner in which Disco allocates the export benefits credit. Disco allocates 100 percent of the export credit to demand. We submit there is a logical foundation for this treatment of these particular credits.

As explained in exhibit A-11 which was a response to CME IR-1, it is the availability of capacity at various times of the year that permits the exports to take place. Logically, any credits arising from this availability of capacity should be credited to capacity or demand.

Both Dr. Rosenberg and Energy Advisors suggests that the export benefits be credited in the manner that Genco sells capacity and energy. So if it's capacity contract credit it to capacity, if it's an energy contract credit it to energy.

It must be remembered that Disco has contracted for and has paid for all of the capacity of the heritage assets. It is surplus capacity that enables exports to be made. In addition, the energy costs related to these exports are covered by Genco and deducted from the sale price to determine the export margin that is shared with Disco.

It is submitted that logic dictates that any benefits for these exports be credited to the capacity that Disco has already paid for and not against energy charges that do not include any amounts for exports. In other words, no energy component.

I would like to turn now to allocation of transmission costs. Disco currently allocates and has in this study -- allocates the transmission costs in accordance with how they are billed under the transmission tariff. Under the transmission tariff, transmission customers are billed based on monthly non-coincident peak.

Now the only opposition to this approach comes from Energy Advisors. They allocate the allocation of transmission costs based on contribution to system coincident peak.

Under cross examination, Energy Advisors admitted that such a change would require the Board to amend the transmission tariff.

It is submitted that Disco's approach is reasonable and consistent with the transmission tariff approved by this Board. A change in the transmission tariff should not, we submit, be done in the context of this hearing, but if the Board wants to look at coincident peak it should be dealt with in a specific Board review of the transmission tariff.

Unless the OATT is changed, we submit that Disco is allocating transmission costs appropriately given the billing determinants of the existing transmission tariff.

The last item under what I would call allocation issues deals with miscellaneous revenue.

There is approximately $15 million in miscellaneous revenue which Disco derives from a variety of services it provides. Since there is no direct linkage between the costs of these services and the revenues, Disco simply allocates this revenue to all classes based on distribution revenues to each class. And this is consistent with the approach approved by the Board in the 1992 CARD hearing.

Mr. Knecht recommends allocating all of these revenues on the same basis as pole plant costs. Yet Mr. Knecht admits that only a portion of these miscellaneous revenues are related in any way to poles. And I cross examined Mr. Knecht on this point and this passage can be found at pages 1889 and 1890 of the transcript.

My question to him was, "So is it 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?" His answer, "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 these -- 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."

I submit that there is no factual foundation for Mr. Knecht's methodology and it should be rejected.

An issue that came forward in the course of this hearing was consideration whether the Board should look to a marginal cost analysis or directing Disco to perform a marginal cost study. And this comes from Energy Advisors primarily.

Energy Advisors is recommending that the Board adopt a marginal cost analysis for purposes of determining the cost of service. They argue that marginal costs will provide a better price signal and will offer the only escape from subjectivity.

I have to say that Disco opposes the move to marginal cost analysis. First, elimination of the residential declining block and merging the general service I and general service II classes, general service II being the all electric class, will accomplish the goal of sending the appropriate price signal. Secondly, it is clear that marginal cost studies are fraught with judgmental decisions.

Energy Advisors themselves outline the challenges to implementation of a marginal cost study on pages 52 to 54 of their report. And you will recall that they listed several challenges and were quite frank in discussing them.

In fact on cross examination, Mr. Adelberg admitted that there are many judgmental decisions that have to be made in the process of a marginal cost analysis. And that can be found in the transcript at page 2176.

So I would submit that far from offering an escape from subjectivity, marginal cost analysis simply substitutes one set of judgments, which is reconciliation, the methodology, what carrying charges you use, et cetera, for another set of judgments. In the embedded cost study there is classification decisions which have to be made. So it doesn't offer an escape from subjectivity.

You will recall that Dr. Rosenberg opposed marginal costs and he set out six reasons why marginal cost studies should be rejected. And those can be found at pages 1511 to 1515 of the transcript. And I will summarize them.

The six reasons why he says you should reject marginal cost studies are as follows. First, no marginal cost study has been provided by either Energy Advisors or Mr. Knecht. Secondly, no other Canadian jurisdiction uses marginal cost analysis and only six US states.

Third, they are no more objected than an embedded cost study. Fourth, marginal costs never equal the revenue requirement. So a reconciliation must be made. And you will recall there was a lot of controversy about which approach you use to reconcile the revenue requirement to the results of a marginal cost study.

Fifth, according to Dr. Rosenberg, even under authentic competition prices will not necessarily gravitate to marginal costs. And finally, Dr. Rosenberg said he could not agree with Mr. Knecht's marginal cost analysis that shows very little difference between serving a 100 percent load factor customer and serving a seasonal customer. So those were his reasons.

Furthermore, in order to do a marginal cost study, one must have access to detailed generation resource and cost information. Mr. Ketchum stated while marginal cost analysis may be appropriate for a vertically integrated utility, it is not appropriate for a restructured utility.

And you will recall that I cross examined Mr. Garwood regarding the use of marginal cost studies with respect to the same Central Maine Power, particularly after it was restructured into a distribution or wires only company.

My question which appears at page 2181 of the transcript, "Now this seems to be touching on something that Mr. MacDougall indicated this morning about using marginal costs for specified purposes. Let me put the question another way, Mr. Garwood. In the jurisdiction where Central Maine Power is today, is a full marginal cost study used for allocation of generation costs." And his answer, "I don't believe so." And that was the distinction from what happened before unbundling to what happened after unbundling. And I submit that we are in the unbundled situation.

As discussed earlier, in connection with the PPA causation approach that I discussed a few moments ago, Disco will not necessarily have access to the detailed generation cost data necessary to conduct a marginal cost analysis. Quite frankly, it is not appropriate for an unbundled distribution utility.

Finally, Energy Advisors notes that one of the benefits of embedded cost studies is that they lead to stability in rates over a marginal cost approach. Energy Advisors concede that a marginal cost study under today's economic conditions would over-collect the revenue requirement. And that's found at page 2080 of the transcript.

Dr. Rosenberg also states that under competition -- and I believe marginal cost studies are intended to emulate competition -- he states that under competition, rates would be higher.

Finally I am going to touch on some rate design issues that came up in the course of the hearing. One dealt with the wholesale revenue to cost ratio. And I examined that the day before yesterday with Ms. Zarnett.

The Municipal Utilities argue that the wholesale revenue to cost ratio should be less than 1.05. Disco set the rates which resulted in a wholesale revenue to cost ration of 1.05. Now this is within the Board approved range and it is in accord with the agreements entered into with the Municipal Utilities. And we went through the two contracts that are involved.

And I will admit the wording of the Saint John Energy contract is permissive with respect to a lower revenue to cost ratio. However, the City of Edmundston contract says that the revenue to cost ratio shall be maintained at 1.05. And of course, the City of Edmundston is part of the wholesale class.

Now ultimately this Board has the authority to set the revenue to cost ratios. Regardless of the contractual relationships which Disco has with its wholesale customers. That is your job. However, Disco's proposal is within the Board approved range and it does not breach its contractual obligations.

I would like to touch on seasonal rates which is another rate design issue that received some discussion, primarily from Dr. Rosenberg. Dr. Rosenberg strongly endorses the implementation of seasonal rates. Both Mr. Knecht and Energy Advisers favor seasonal rates as well, but make no specific proposal.

I would like to be clear that Disco is not necessarily opposed in principle to seasonal rates, but it is very cognizant of the customer impacts.

For example, Dr. Rosenberg's seasonal rate proposal for the residential class would result in an annual average impact of 15.8 percent. However, and you will recall, we went through the monthly calculation, calculated on a monthly basis, there are months when the impact on customers is 39 percent.

Now Mr. Marois testified that the implementation of seasonal rates would introduce a level of complexity from the customer's perspective which generally is not warmly received.

Mr. Adelberg also commented that customers are sensitive to major rate structure changes. And that his experience in Maine was that it -- if my notes are correct -- that it caused a public uproar.

Perhaps more significantly, Disco believes that seasonal rates should not be implemented until the residential declining block is eliminated and the general service I and general service II classes are merged.

Implementing seasonal rates before these changes would be illogical and inconsistent. That is part of the rate would go down in the winter, as consumption increases, and part of it would go up as a result of the seasonal rate. It would also create undue confusion for the customers and needless administrative burdens on Disco.

So our position basically on seasonal rates is we are not opposed to them in theory, but let's get rid of the rate design problems that we have now that send improper price signals before we -- let's walk before we run.

And I guess that leads into my next point which is the elimination of the declining block for the residential rate. I think all parties, including Disco, seem to agree that the declining block feature of the residential rate needs to be eliminated.

Really the only issue is one of pace, how fast do you do it. We should be mindful that a very large percentage of New Brunswick Power customers, Disco customers, 60 percent in fact, have electric heat. Disco is mindful of the impact of high energy prices on the residents of New Brunswick. We submit that we have applied the principle of gradualism to our rate design proposals.

Unfortunately with high fuel prices, this is a particularly poor time to make aggressive adjustments to rates that will impact heating bills. And similar to the declining block and the residential block, we have the elimination of the general service to all electric rate. And again, all parties seem to agree that the general service rate should be eliminated. General service II rate, sorry, should be eliminated. Again, the only issue is how fast. And again, we would submit that Disco's proposal incorporates the principle of gradualism. This proposal also includes closing the general service II rate to new customers to limit future rate impacts. I would like to comment briefly on general -- on Energy Advisers' recommendation about splitting the general service rate class based on voltage. Refer to it as a primary, secondary split of that class. Energy Advisers are recommending that the general service class be differentiated by voltage level and are asking the Board to direct further research on this issue. Energy Advisers' revenue to cost ratios upon which they base their recommendations are not base on empirical revenue data. And you will recall I brought Mr. Garwood through whether he had any revenue figures that he put in his lines in his study. And he agreed on cross examination that he had to basically assume -- make some assumptions with respect to revenue.

So I would say based on that alone that their recommendations are not based on any empirical data and I would go on to say that Disco does not object to examining the viability of a primary, secondary split of the general service class. But it does have concerns similar to those it has with respect to seasonal rates.

This should only be done after merging the general service I and the general service II classes in order to reduce the impact on customers. It just does not make any sense to create additional classes now that we will only have to remove sometime very shortly in the near future.

And I would like to speak, before I conclude, generally on the issue of revenue to cost ratios. Energy Advisers alleges that revenue to cost ratios cannot be used to determine whether or not cross-subsidies exist.

Mr. Adelberg admitted during my cross examination however, that revenue to cost ratios could be and often are used to measure equity and fairness, and that appears at page 2193 of the transcript.

Dr. Rosenberg and Mr. Ketchum also supported the use of revenue to cost ratios based on embedded costs as an appropriate and commonly used measure of equity.

The 1992 CARD decision of this Board acknowledges the use of revenue to cost ratios as an appropriate measure of equity and the Energy Policy White Paper acknowledges the same and even seems to equate the movement of energy costs -- of revenue cost ratios to within the range of 95 to 105, with a commonly understood notion of eliminating cross-subsidies.

Based on the evidence, Disco submits that its understanding that revenue to cost ratios within the range of 95 to 105, based on soundly constructed embedded cost studies can reasonable be used as a basis for a determination that cross-subsidies among classes of service do not exist.

I am going to conclude now, Mr. Chairman and Commissioners. As Mr. Marois stated in his evidence, rate design is not a science, but an art. There is no mathematical formula that will enable this Board to input numbers and spit out a perfect result.

All the experts that you have heard here agree that there is no such thing as a perfect cost of service study. This Board is faced with competing opinions from very qualified experts. The issue for you, therefore, is which approach is most reasonable and best reflects the reality of Disco's cost causation.

It is submitted and we submit that Disco's proposal represents the most reasonable and balanced approach.

Energy Advisers stated while they took issue with some elements of Disco's approach, the cost of service recommendations by -- made by Disco are generally well documented and suited to Disco's circumstances.

Mr. Knecht, and there amy be some controversy over this, ut I believe Mr. Knecht said that Disco's approach did not necessarily produce unreasonable results. By definition, Disco has to consider the reasonableness of its rate proposal to all rate classes.

In particular, Disco is sensitive to the impacts its rate proposals will have on all customer classes. The other Intervenors have self-interests to advance. Look, that is normal and it is understandable. Disco really doesn't.

And I would submit that Disco's cost of service study should be accepted over the others offered for a number of reasons. First, it recognizes the realities of restructuring in Disco's real price driver, which is the PPAs. It is based on Board approved methodology. Where classification judgments are required, I would submit that Disco can do so objectively. And unlike some of the other parties, I would suggest, it considered gradualism and rate impacts to a greater degree on its customers in putting forward its proposals.

In summary, we submit that Disco's study represents an even handed and therefore, fair and reasonable approach. And those are all my comments, Mr. Chairman. Thank you.

CHAIRMAN: Thank you, Mr. Morrison. And congratulations. That was 37 and a half minutes. Closest I have ever seen a lawyer come in this room.

MR. MORRISON: I aim to please.

DR. SOLLOWS: A plus.

CHAIRMAN: Let the record show that Mr. Coon is here representing Conservation Council and has been here for the last ten minutes. And we will take our break.

(Recess)

CHAIRMAN: Just for those of you who are not familiar with this process that we are presently involved in, in summation, why the Applicant goes first, as Mr. Morrison has today. Then we will go through the Formal Intervenors in alphabetical order. At the end of the day, hopefully we will be through with that. The Board will take a brief recess. We have got some things that we enumerated yesterday that we would like to see the parties address. And if they have not been addressed, then we will come back in and say, okay, tomorrow we will ask you in your rebuttal to address them.

The tomorrow the order is reversed and you will start with the Public Intervenor and go back to ending with Mr. Plante and then finally Disco.

Now each of you will be addressing the issues that the Board puts in front of you or wants you to emphasize for the first time and so hopefully, you will be able to expand upon those. Otherwise you are simply rebutting what parties who came after you -- sorry, parties that came after you and said things that you couldn't reasonably anticipate when you were addressing the Board today.

Now that is all as clear as mud and we will go from there. Mr. Plante, do you want to address the Board?

MR. PLANTE: Thank you, Mr. Chairman, Commissioners. My remarks this morning will be brief and are intended to emphasize the crux of the evidence presented by CME's chief economist, Jay Myers.

I will also take the opportunity to reiterate CME's position with regard to some of the points raised in our presentation as well as in the cross examination.

Firstly, as you are well aware, CME's evidence is intended to raise awareness of the impact of higher electricity rates on the competitiveness of New Brunswick manufacturers and on their ability to generate the funds required to reinvest in their operations to ensure their longterm sustainability.

Some questions had been raised as to whether this evidence was appropriate to this phase of the hearings. We felt it was, however, indeed pertinent since the issue of industrial electricity rates was raised in the Applicant's evidence as well as in the evidence submitted by subsequent Intervenors.

And of course the large industrial class of customers have become the focus of much of these proceedings.

Finally, as noted by the Applicant as well as a number of the Intervenor's experts, cost allocation and rate design is by no means an exact science. It involves a considerable amount of assumptions, projections and judgment.

I am by no means an expert in CARD, but I do understand the Board has some influence in designing rates. In this regard we felt that our evidence was essential to this process.

Mr. Myers presented evidence as to the contribution of manufacturing in New Brunswick's economy. While many people don't realize that New Brunswick's economy is the third most manufacturing intensive province in Canada and directly employs nearly an eighth of our work force, most would also be surprised to learn that the multiplier effect of New Brunswick's manufacturing community is the highest in Canada which indirectly creates many more jobs through the purchase of supplies and services.

Most people, however, realize that our economy is heavily weighted towards resource extraction processing and when a mill closes in a small town, it has major ramifications for many people.

The fact that our economy is resource based is significant. Firstly, our products are largely commodities that are traded in the international marketplace. As such, cost increases generally can't be passed on to customers, but must be absorbed and unfortunately sometimes in the form of workforce reductions.

As well resource based industries are typically energy intensive. For many of our operations, energy and electricity compromises a much greater portion of their operating costs than the average 4 percent noted in Mr. Myer's evidence.

Of course, rate increases don't exclusively impact commodity producers or larger industrial operations. Most New Brunswick manufacturers export their products to the US and elsewhere. In today's marketplace the consumer has many choices and invariably will search for a lower cost supplier or alternative process inputs in order to remain competitive themselves.

Very few producers can pass along cost increases onto their customers. As noted in CME's evidence, our membership includes companies that are in the large and small industrial classes, general service and even service by wholesale service providers.

Unfortunately it wasn't possible to provide evidence of specific New Brunswick operations that are most sensitive to electricity rate increases. I hope that the Board appreciates such information is company confidential and commercially sensitive information. Inappropriate release of such information could have significant adverse impacts on these operations.

As opposed to forward looking statements, CME evidence pointed to cases where cost increases related to energy and electricity have played a major role in decisions to close a plant. And there have been even more announcements of plant closures since the preparation of CME's evidence.

In many ways New Brunswick can be seen as a microcosm of Canada. While we may not be able to specifically point to New Brunswick operations at risk, it would take more than a leap of faith to think that a hike in electricity prices won't impact their competitiveness and their viability.

As well, CME presented evidence as to the role energy costs play in a company's investment decision. Is the price of electricity the only factor in decisions to close an operation or open a new one? Of course not.

But a myriad of cost increases have been imposed on New Brunswick manufacturers in recent years, from environmental fees to payroll taxes. It has been suggested in the cross examination that an adjustment to some of these factors could offset an electricity price increase.

However, for many manufacturers the impact of an electricity price increase would be much greater than the hike in any of these other levies. And of course the agencies responsible for those increases would argue just as strongly that their hikes are justified.

It is also important to note that CME isn't advocating that a particular rate class should pay more for the services they receive than any other rate class. The question has been raised, however, whether the new Electricity Act affords industrial customers -- whether under the new Electricity Act, industrial customers have greater flexibility to access alternative electricity suppliers. In reality there is significant technical and regulatory barriers to the introduction of effective competition in New Brunswick's electricity market and given the magnitude of capital investments required to generate -- required for generation capacity, industrial customers actually have less flexibility.

It has been questioned whether rate classes with revenue to cost ratios less than 1 could be considered to be receiving a subsidy at the expense of other customers. And it must be noted that CME's evidence provide an example of the impact of charging the large industrial class an additional $14 million or roughly the difference between the costs allocated to this class and the amount that is projected to be generated from large industrials.

This figure was chosen only as a convenient basis for illustration purposes. The Public Utilities Board has quite appropriately chosen a range of reasonableness for cost revenue ratios of 0.95 to 1.05. Chasing a target of unity for every rate class R ratio would be a mug's game.

Should the Public Utilities Board decide that it is a desirable objective, it should do so because the precision of the cost allocation process has improved and not because of some misconceived perception of inter-class subsidization.

Finally, CME's evidence has been described as a hardship case. We take exception to this characterization. No other Canadian jurisdiction can point to as mane examples of companies rising to world class status from such humble roots. And the key to our success has been our savvy and our perseverance and not the public purse.

CME has consistently said that consumers should pay a fair and reasonable price for their electricity. We believe that the price paid by manufacturers for electricity has covered the costs given the ambiguity and the uncertainties of rate design. And it is our understanding that the methodology used by NB Power to allocate costs is consistent with industry practices, particularly given the changes in the landscape over the past few years.

Great care should be taken in rejecting the utility's experience and assessment that's inherent in this proposed cost allocation and rate design.

Thank you very much for your time.

CHAIRMAN: Thank you, Mr. Plante. Conservation Council, Mr. Coon?

MR. COON: Thank you, Mr. Chairman, Commissioners. I would like to say that it was a lovely morning in the port city this morning. The weather was beautiful.

There has been -- most of our discussion -- most of the discussion and evidence here has been around the appropriate allocation of costs among customer classes.

It's clear though from the evidence that there is an important issue that concerns the allocation of costs, which we believe the Board needs to address, and that is the allocation of costs to the end use of electricity sold to customers. And what I am referring to is the allocation of costs to customers using electricity for space heating.

The evidence that's been put before the Board clearly demonstrates that providing electricity from Disco for space heating is a costly -- a costly item for Disco, expensive end use to serve.

Mr. Marois in his evidence says clearly, and under cross examination from myself, has clearly indicated that Disco seeks to reduce the demand for electric heat from its existing customers and discourage new customers from adopting electricity for space heating purposes.

This might lead one to conclude then that there should be new customer classes, and that is customers using electricity for heat. In other words, how we can appropriately allocate costs to those customers using electric heat if they aren't in their own classes. And then if that were done, of course, the cost revenue ratios set out by the Board could be achieved in those customer classes.

The problem with this approach is that it would be -- I would submit patently unjust. For decades now, the price signals to customers using electricity have sent them in the other direction. They have been quite inappropriate to discouraging the use of electricity for space heating, which is now what Disco suggests they are -- they want to do, in an exact opposite direction they encouraged the use of electricity for space heating, both through the general service, all electric rate for general service customers and the declining block rate for residential customers. Worse, residential customers some 20 years ago were paid $800 in grants to abandon perfectly good heating systems in favour of electric space heating systems by New Brunswick Power.

So allocating these full costs to a new class of electric heating customers or new classes might be appropriate if the Board were in fact able to order -- to order Disco to provide a grant to its customers who use electric heat, say the $800 that was paid out in 1982, '3, '4, '5 in 2006 dollars today, whatever that might be, to help them get off electric heat or reduce their demand through energy efficiently -- sufficiently to offset the increasing cost that would result from this move. But that is probably unlikely.

So I would submit the priority has got to be placed on discouraging new customers from adopting electric heat. This is something that Mr. Marois, that Disco has put forth in their estimate -- in their evidence as an objective. And it is a way of ensuring that costs -- other customer classes are not put in the position in the future of having to cover costs that electric heating customers should otherwise cover.

We believe this can most effectively be accomplished through rate design. Eliminate the declining block rate now. In fact, reverse it. And what we would submit is this could be done fairly easily by simply reducing the cost of the first block of power purchased by customers so that it is lower than the later blocks they currently pay for. And then eliminate the all electric rate for general service customers now, not later, but now.

If the Board feels it is within its powers to soften the impact of whatever rate increase gets approved at the next set of hearings, given the changes in rate design I am suggesting here and the time period, the time frame I am suggesting, we will argue in those hearings that Disco should be returning some of its revenue back to its customers to assist them in making the necessary investments to enhance the energy efficiency of their buildings or to fuel switch to offset the increased costs that a rate hike would otherwise impose to them.

Thank you very much.

CHAIRMAN: Good. Thanks, Mr. Coon. Mr. MacDougall? How long do you anticipate you will take, Mr. MacDougall?

MR. MACDOUGALL: Fortunately or unfortunately, Mr. Chair, from whoever's perspective it is, I will be a little longer than Mr. Morrison. I would anticipate an hour and 15 minutes.

CHAIRMAN: Good. Thank you, sir.

MR. MACDOUGALL: Now that I know we are being timed, I am a little more cautious about the --

CHAIRMAN: There was a judge of the Queen's Bench Division who used to do that to us, especially during divorce time.

He would actually take his watch off and put it up. Of course you had to put in your trial record how long you anticipated it would take. So some of us would put three minutes and 32 seconds, things like this. So I will not get that fine, but --

MR. MACDOUGALL: Thank you.

CHAIRMAN: No, I think I wanted to know in particular from you, we will probably go right straight through until 12:30 today then, if that's the case, so you can conclude.

MR. MACDOUGALL: And as I say, Mr. Chair, if it happens I am continuing and it's an appropriate time we could break and come back. There is various spots in my argument that I will leave you to guide the time and I will just continue to plough on unless you say otherwise.

Mr. Chair, Commissioners, thank you for providing Enbridge Gas New Brunswick this opportunity to present its final argument in this matter.

As the Board is aware, EGNB is focused on three main areas, the appropriate cost of service study for Disco at this time, rate design issues for the residential class in the general service I and general service II classes, and, three, the requirement for a standby rate for customers with self-generation.

I intend to deal with the rate design issues first, the obverse of the way Mr. Morrison dealt with it, the standby rate issue second and the cost of service issue last.

However, before dealing with each of the three specific subject areas a couple of general comments are warranted.

First, it is not my intention today to reiterate the record in any great detail. There has been a significant amount of evidence put before the Board both by Disco and the Intervenors and there has been extensive direct and cross examination of all of the key issues in this proceeding.

We believe the Board has the benefit of a full and complete record before it. And the purpose of this final argument will be to highlight those primary conclusions which we believe the Board should draw from the record as being in the public interest.

Second, it is important for the Board to understand, I believe, the perspective from which EGNB entered into and participated in these proceedings. Suffice it to say that it is probably not a common occurrence when one utility significantly intervenes in the regulatory proceedings of another. However, the circumstances of this case clearly warranted such intervention.

As the Board is fully aware as the regulator of EGNB as well as of Disco, EGNB holds the general franchise for the provision of natural gas in New Brunswick. With the advent of the availability of natural gas in the province, New Brunswick energy policy has moved towards encouraging the most efficient use of the mix of available energy resources for the citizens of New Brunswick.

For many years the province's focus was on its crown owned utility, New Brunswick Power Corporation. And its goal was to foster the growth of the utility and to make electricity widely and cost effectively available to the citizens of New Brunswick. And I believe Mr. Coon has just alluded to that.

Today however, with the availability of natural gas and of course the continuing availability of heating oil, and with ever increasing energy prices, the goal is now the most economic and efficient use of the energy resources available, with a heightened awareness on demand side management initiatives, conservation and protection of the environment.

As such, the goals of the province, its wholly owned electric utility and we believe this Board, are now much different than they were 15 years ago. Accordingly, EGNB felt it not only appropriate but necessary to actively intervene in the generic portion of this proceeding dealing with cost allocation and rate design.

It is those generic aspects of the overall rate case in which the Board will be setting down the generic principles which will primarily guide the utility with respect to how it approaches price signals, energy efficiency and the proper utilization of available resources for the next number of years.

Accordingly, although EGNB is not likely to actively intervene in the revenue requirement portion of this hearing, it felt it necessary to participate fully in the generic cost allocation and rate design aspect.

EGNB has focused on the proper underlying economic rationale for cost allocation and rate design at this period in Disco's development, with an eye to the underlying policy objectives of the province and the public interest of the energy consumers of New Brunswick.

EGNB's view is that Disco's costs should be based on appropriate cost causation by customer class, and that the removal of the distortions in Disco's proposed cost of service study and rate design are the appropriate approach to create a level playing field.

Marginal cost pricing may well indicate higher prices going forward, and again I believe Mr. Morrison alluded to that this morning, but for reasons that we will discuss later these prices are not the basis for the costs appropriately borne by New Brunswick electricity consumers at this time.

Dr. Rosenberg and EGNB have remained faithful throughout this proceeding to the principle of cost causation, one of the most fundamental principles of economic regulation and one which they commend to this Board in the public interest of electricity consumers of New Brunswick.

In the remainder of this argument we will highlight how Dr. Rosenberg and EGNB's recommendations reflect true cost causation as currently experienced and likely to be experienced for some time in New Brunswick.

Mr. Chair, I would note I'm not going to make very many transcript or other references but I do have hard copies of my argument which I will share with the Board later and have already agreed to share with the court reporter.

So first as I mentioned earlier, I would like to start with rate design.

The reason for dealing with this item first is that EGNB believes there is little if in fact any disagreement among all of the parties in this proceeding, Disco and the

Intervenors, on where the Board should fundamentally go with rate design.

The real issue in fact which seems to be the only primary issue is not where we should go with rate design but, as Mr. Morrison alluded to this morning, how quickly we should get there.

Let me go briefly through EGNB's recommendations and I will come back to the issue of timing and detail a little later on.

First with respect to the residential rate. Mr. Marois, Mr. Knecht, Messrs. Adelberg and Garwood, together with Dr. Rosenberg, are all receptive to ultimately eliminating the block differential and the residential rate so as to be more reflective of cost of service considerations. Full agreement.

In fact both Mr. Marois and Mr. Adelberg indicated that at some point an increasing block structure may even be appropriate. And Dr. Rosenberg was not adverse to such an inverted block for those customers. It is clear, Mr. Chair, Commissioners, if we are to send the proper price signal to residential electric customers, and in particular residential electric heat customers, the declining block structure must go. It is sending the exactly incorrect price signal at present.

Again, as we believe there is no disagreement on this fundamental point, we will not highlight the numerous references posed by the various parties throughout this proceeding but again commend the record to you.

It is also abundantly clear from the record, and in fact we believe well-known by everyone in this room, that Disco is a markedly winter peaking utility, and that its load at peak hours is driven by electric heat. This nature of the NB Power system has driven its capacity requirements in the past and will continue to drive them in the future.

Disco has as its statutory mandate the requirement to continue to serve the native load of the Province of New Brunswick and its system and the generation it has acquired through the PPAs is designed to meet NB Power's winter peak demand.

As such, in order to send the appropriate price signal in New Brunswick there must be a seasonal component to electric rates. To avoid doing so ignores one of the fundamental drivers of NB Power's costs. In fact the 1994 Reed Consultant Group report on specified rate design issues commissioned by NB Power, of which Mr. Ketchum was one of the authors, specifically recommended cautioning the application of long run incremental cost peak load pricing principles, and then stated that the efficiency benefits of long run incremental costs could be achieved through seasonal rates developed from accounting data without disrupting other important rate design objectives and without referring to long run incremental cost estimates.

This point was picked up on by Messrs. Adelberg and Garwood in this proceeding and they also specifically noted that seasonal differentiation of embedded cost based rates is desirable.

In fact Ms. Zarnett during her recent cross examination by Mr. MacNutt just two days ago, when asked about her view on time of day pricing, indicated that both time of day and seasonal rates had worked well in jurisdictions in which she has recent experience.

Although recommending seasonal differentiation of embedded cost base rates, Mr. Adelberg noted that he and Mr. Garwood had not made any specific changes to Disco's CCAS that would reflect seasonally differentiated fuel costs. And again Mr. Morrison alluded to that this morning.

Dr. Rosenberg, however, not only espoused the general requirement for seasonal rates in Disco's circumstances, but he went the further step and proposed a seasonal based rate structure to the Board, which is in the record and in his evidence.

EGNB believes that the record is undeniable in its overwhelming support for the elimination of the declining block and the addition of seasonality to Disco's rate structure. In fact this is exactly what Dr. Rosenberg has proposed in his evidence. And we commend this rate design to the Board as it is fully reflective of the record in this proceeding, the underlying cost drivers of Disco's customer costs, sound economic principles and common sense and practicality.

EGNB's specific recommendations with respect to he residential rate design can be found at pages 41 through 46 of Dr. Rosenberg's direct testimony, exhibit EGNB-1.

CHAIRMAN: Mr. MacDougall, one thing that bothers me about seasonal rates is that with the way the PPAs are structured, there is no way that the residential consumer can in fact reduce his electric bill or switch it on a seasonal basis because there are no -- there are no meters to allow him to do that. You know, he will be -- I'm sure each of us who has electric heat is fully well aware that we are driving the winter peak and we consume far more in the winter.

But you know, basically there is a disconnect because

Disco can't purchase its electric power that way on a seasonal basis. Any comments on that?

MR. MACDOUGALL: Sure, Mr. Chair. I would be delighted to comment on that. First of all, on the metering issue, there is a big difference here between time of day rates and seasonal rates. Seasonal rates do not require a meter change. They are differentiated by two times of the year. They require no metering adjustment at all. And in fact, Dr. Rosenberg and I believe some of the other experts in their evidence stated that there are practical difficulties with time of day rates, but if we want to move in that direction, seasonal rates can be accomplished without the practical concerns of time of day rates, particularly metering and administrative concerns.

The other issue, Mr. Chair, is the PPAs may be there and they are structured in a way that's design has a price component built into it that Disco is going to pay. But the drivers to the costs of the PPAs, the entire fundamental basis of the drivers to the costs of the PPAs, is the current generation mix of Genco. And those costs that are borne by the customers in New Brunswick, if we don't look past the PPAs, then e are not looking at all as what the drivers are of the overall costs in those arrangements. And then we are fundamentally saying because the PPAs exist, we can't look at any of the drivers behind what is causing the usage or the costs by customer class in New Brunswick. To do so then would be, as Mr. Morrison alluded to this morning, would be to say that you are taking section 156 of the Electricity Act, and although this Board has ordered that we can look past the PPAs for the purpose of cost causation, if you followed your argument, you would be precluded from doing that. And in no way would the customers of New Brunswick ever be being sent a price signal that indicated to them the costs they are creating for the generating assets that are actually creating -- producing their electricity,

MR. DUMONT: Mr. MacDougall, when you are talking about seasonal rates, will that apply to all cases even if that class doesn't cause the increase?

MR. MACDOUGALL: No, Commissioner Dumont, for seasonal rates we are really looking at it for two classes. Those that really have a winter heating load, so the seasonal rate structure would be in the residential class that clearly has a winter peaking heating load and in the GS II classes that have commercial and industrial entities that also have a markedly winter peaking load.

It wouldn't apply, for example, to large industrial customers because they have a flatter load throughout the year because it is for process reasons. So the seasonal rate is designed to specifically be aimed towards those customer classes that have a seasonal component in their usage.

MR. DUMONT: Thank you.

MR. MACDOUGALL: Thank you, Mr. Chair.

DR. SOLLOWS: Mr. MacDougall, you alluded to the industrial customers having a flatter profile. My recollection of the evidence was that some significant number of industrial customers have what would be characterized as fairly low monthly and annual load factors. Do you have direct information that those customers are not using energy preferentially during the winter versus the summer?

MR. MACDOUGALL: I don't have -- there is no specific information in the record on that, Commissioner Sollows. I do know, and I recall when you referred to that earlier in the proceeding, I do think even the lower load factor industrial customers have a significantly higher load factor than for example, an electric heat -- residential electric heat customer. And I am assuming there are some process issues with some of the smaller industrial customers.

Certainly the larger industrial customers, such as ones that were referred to by Mr. Plante, the pulp and paper mills, et cetera, were the 85 to 90 percent range. I do note that some of the industrials within that class had a lower profile and there might have been some aspect of seasonality to those. If in future Disco was able to bring information forward that was able to figure out whether that was heating, space heating as opposed to say process reasons, then certainly one could consider some aspect of seasonality if one felt that the load profile of those customers actually was driving that.

DR. SOLLOWS: I guess then my fundamental question in my mind is why does it matter that it is space heating as opposed to being used near the coincident peak demand?

MR. MACDOUGALL: Well again that is the information we don't have. I don't think the data showed every month. And see, for some of those customers, they might have had a low profile. I don't know that it was at all attached to heating reasons.

The thing with seasonality is you can tell with certain customer classes, particularly the residential to a lesser extent, but still quite significantly with the GS all electric class, that it is clear that what is driving their usage in the winter time is heating needs. And therefore, their usage is tied into the winter peak for the exact reason that you would expect.

With some of the load factors of the large industrials, there may be process issues throughout the year that we are not aware of because you need further information on their actual load profile, not just their load factor.

DR. SOLLOWS: Thank you.

MR. MACDOUGALL: You're welcome. And again, I appreciate the comments of both the Chair and the Commissioners and I think some of this comes back to a comment that I will make later, but I think should be made now.

As Dr. Rosenberg said, we all have to be very cautious that we don't let the perfect be the enemy of the good. We have to try and do what we can with the data we have and what we do know. We certainly know that the electric heat customers in New Brunswick are causing significant costs that currently are not differentiated in any way.

Just to go on then with our argument. As Dr. Rosenberg had indicated in his direct examination and as more fully explained in the page references that I just referred you to, not only is his rate design for the residential class more cost based than that of Disco, but it also narrows the revenue to cost differential between the heating load and the non-heating load. And therefore, it is more conducive to both demand side management initiatives and to fuel switching.

This latter point is important because it is fully in line with the government's recent creation of an energy efficiency agency and with the more efficient use of natural gas directly for home heating than for the production of electricity. The significant discrepancy between the high efficiency usage of natural gas as a direct heating source versus its conversion to electricity was highlighted in EGNB's cross examination of Mr. Marois. And again, we refer the Board to the record in this regard and the transcript references are in my written argument.

So for efficiency purposes, well it is very important to try and suggest to people that they use the right resource or the right form of energy to ensure we maximize the efficient use of that form of energy.

Both Dr. Rosenberg and Mr. Adelberg indicated that seasonally differentiated rates were easy to administer and easy for customers to understand. I know Mr. Marois has indicated that they are not as easy as leaving things as they are, but notwithstanding that, the other experts have not felt that seasonally differentiated rates were that problematic.

- Dr. Rosenberg specifically noted that there is no requirement for new meters for seasonally differentiated rates, as I just mentioned, Mr. Chair. And Mr. Adelberg specifically noted that there is only a requirement for two discrete billing periods, winter and non-winter.

Now let us turn to the general service I and general service II rates. For the same fundamental reasons that underpin EGNB's proposals with respect to the residential rates, Dr. Rosenberg proposes that the GS rates be equalized and again seasonally differentiated.

As Dr. Rosenberg noted in his direct examination, the current differences between the GS I and the GS II rates are not supported by any cost of service principles, but are essentially there for purely promotional reasons.

Again this harkens back to the comments I believe the same reference made by Mr. Coon earlier today.

Disco's proposal is to close off the GS II rate and to make adjustments in the demand charges that start to bring the two rates closer together. Although EGNB is firmly of the view that at a minimum the GS II rate must be closed off to new customers, and supports that aspect of Disco's filing, it believes there remains an issue with grandfathering the existing GS II customers, if that is all that occurs.

First, there will be little, if any, incentive for the large number of existing GS II rate customers to consider conversion away from electricity, in that once grandfathered, if they decide to switch their heating load away from electricity, they would lose their status as an all electric customer and would actually pay more per unit of consumption for their remaining non-electric heat load than what they were paying under the GS II rate.

As Mr. Marois confirmed on cross examination, this is the opposite price signal from what is being sought, even by Disco since it is the electric heat load that is more costly for Disco to serve.

Second, Disco has made no proposal with respect to the time frame in which the GS II grandfathered customers would be phased out and a single GS I class created, therefore, giving no indication to the grandfathered customers as to when they will be seeing a more correct pricing.

Third, we note Mr. Adelberg's concern that grandfathering certain customers in a certain business may provide a competitive advantage over new entrants into a similar business who would not be able to access the grandfathered GS II pricing and this result should be avoided, if possible.

As such, while EGNB and we believe all parties in this proceeding believe at a minimum that the GS II class must be shut off to new customers as proposed by Disco, this is far from an optimum resolution and more significant steps such as proposed in Dr. Rosenberg's evidence should in our respectful opinion be taken.

Dr. Rosenberg's specific recommendations with respect to the GS classes again are found in his direct evidence at pages 46 through 49. In particular I note his statement at page 47 that his rate structure would provide the general service customers with much better price signals and would encourage more efficient use of fossil fuels.

Before moving to the issue of timing which I stated earlier I would return to, I think a few further words on seasonality are warranted, particularly in light of the comments that were just made by the Chair and the Commissioners. And I think this may be helpful because I think it will bring out some of the issues on seasonality in the record.

If we refer back to the 1994 Reed consulting report they had stated that to the extent that efficiency goals are important seasonal rates will provide a greater incentive for the consumer to pursue demand side measures which in turn will delay capacity addition requirements.

Thus seasonal rate making can serve as a complement to demand side management measures already underway. This would be the case whether or not we have Genco as the generator or a combined bundled utility.

Yet NB Power has not instituted seasonal rates since 1994. Although as Dr. Rosenberg notes in his direct evidence, it may be impractical at this time, again as I mentioned earlier, to use time of day rates, such practical considerations do not present themselves with respect to seasonal rates. And this would be a significant first step towards more real time pricing in New Brunswick at this time.

This is the case for the general service rates as well as the residential rates.

DR. SOLLOWS: Mr. MacDougall, if I may just clarify, it was my understanding from the conversation or the evidence of your witness that there were not likely any technical limitations to introducing time of use or real time rates for transmission service level customers because of the nature of their metering, is that correct?

MR. MACDOUGALL: I believe they probably have proper interval metering. I can't say that with respect to every transmission customer, but I would think the large transmission customers do have that.

DR. SOLLOWS: Thank you.

MR. MACDOUGALL: I can comment a little further on that if you would like. I think the issue there is there are some other rate structures already available to those customers. There is an interruptible rate, there is a curtailable rate. So there are rate structures there. And most industrial enterprises tend to use -- again if they are using -- if they have a higher load factor they are using electricity because they have to use it for their process needs on a regular basis.

However, if one wanted to develop some form of real time pricing alternatives that would be available to a large industrial to then see if they could utilize those, that has certainly occurred in Nova Scotia over the past number of years.

There have been technical difficulties with some of those rates but certainly if they are there as an option for a large industrial to attempt to have some real time pricing, then certainly that's useful for moving load from on peak to off peak. There is no doubt about that.

Now Disco in particular has raised its concern with the possible need for gradualism in rate design revisions. If at the end of the day the Board is concerned with the ultimate rate impacts of EGNB's proposed rate designs, EGNB is fully cognizant of the competing principle of gradualism and believes that there are ways to approach this issue, while at the same time ensuring proper price signals are sent to the market in a timely fashion.

First it is important to note, as put forward by Dr. Rosenberg in his direct evidence, that Disco's approach seems to suggest that the proffered rate design proposals will have no impact on the customer behaviour. As he noted, it must be remembered that when comparing the impact of a potential rate design change, most analysts use the same billing determinants for both current rates and proposed rates.

However, as he specifically noted, this is not quite accurate in that the whole purpose of putting in more cost based rates is to elicit a customer reaction.

For example, the goal of seasonal rates and the elimination of the declining block is to motivate the customer to lower its winter usage or to choose a more efficient heating option and therefore lower the customer's overall costs.

MR. NELSON: Mr. MacDougall, may I ask you a question?

MR. MACDOUGALL: Certainly, Commissioner.

MR. NELSON: Is your client -- do they have seasonal rates?

MR. MACDOUGALL: Right now my client has a very unique rate structure which is market based and it's there because it's in the very early stage of developing the natural gas utility. So it's based off of competing fuels and essentially a discount off of the price of heating oil in the marketplace.

So because of that they do not currently have seasonal rates. But the difference really is -- the difference, Vice-Chair, is that we are really talking about utilities in very different stages of their development.

Here we have a very mature utility with a very mature customer base. EGNB is in the growth stages of its utility and as I say, has very specifically developed a type of rate structure that is more market oriented and which this Board has approved is appropriate for a developing Greenfield natural gas market.

MR. NELSON: That's fine. Thank you.

MR. MACDOUGALL: And I have to say I can't comment whether the Enbridge group of companies has seasonal rates elsewhere, but they may well. Clearly I think we are at very early days for natural gas rates in New Brunswick. So to move to seasonal differentiation probably is something that may happen in the future but certainly is not currently part of their market based approach.

While on this point, I did note the issue raised by Commissioner Bell of Mr. Adelberg as to whether budget billing would somehow diminish the price signal. And we essentially support Mr. Adelberg's response to the Commissioner in that although budget billing spreads the actual costs more evenly over the billing cycle, it still recovers the overall cost to the customer, and in fact customers often opt for budget billing where they see that their usage is increasing their costs in, for example, the winter months and they would rather spread the charges more evenly during the year for budget purposes. They however still get the correct price signal.

This leads us to the most important issue with respect to the matter of customer impact and gradualism. This is we should get the rate designs correct and then if necessary the Board can temper customer impacts if they feel that this is warranted.

It is clear from the record that Dr. Rosenberg, Messrs. Adelberg and Garwood, and Mr. Knecht, all support this principle. In fact I would go so far as to suggest that Disco also supports this although their responses were much more generic and open ended, an issue which I will come to shortly.

Specifically we will refer you to page 70 of Messrs.

Adelberg and Garwood's direct testimony where they state,

"Rather than allowing customer impact concerns to stand in the way of realigning customer classes, the better approach would be to create separate classes and phase any rate changes in gradually to avoid rate shock. In addition, capping techniques can be employed to avoid impacts on customers with very unusual usage characteristics."

And likewise at pages 73 and 74 of their testimony in dealing specifically with seasonal pricing they note that they are not persuaded that customer impacts would be sufficient to ignore moving in that direction, and that seasonal rates should be implemented and this could be done so gradually if necessary to mitigate impacts.

That was Mr. Adelberg and Mr. Garwood.

We also note the Public Intervenor's view for example that large energy users such as farms and churches could possibly be separated from the residential class so as not to skew or create any unusual results when applying the appropriate rate design changes to the remainder of the more cohesive class.

EGNB supports such concepts as phasing in and capping, but again obviously only if the Board feels there is in fact an unwarranted customer impact arising from the application of its proposed rate design.

In fact Dr. Rosenberg specifically addressed the issue of gradualism in his direct evidence. Particularly with respect to the GS class, he noted, he has tried to balance cost of service with proportionality.

And with respect to phase-in, Dr. Rosenberg on redirect noted that if the Board did have issues with respect to customer impacts arising from its ultimately determined rate designs, that phase-in over a couple of years could be considered, and in his words, at the most three years.

This latter point we feel requires some further elaboration.

As the Board would have noted from Mr. Marois' direct testimony and his responses on cross examination, and from Mr. Morrison's comments this morning, Disco has put forward no proposal for the phase-in of rate changes for either the residential or GS classes, but rather they provide very generic statements to the extent that it will all depend on the circumstances at any given time in the future as to what Disco may or may not propose. And I give transcript references for that.

Mr. Chair, Commissioners, this is a point with which we believe Disco is in marked contrast with all of the other Intervenors.

To begin with, the record is clear that NB Power, prior to restructuring, although making some modifications over time, has really not dealt with the issue of sending appropriate price signals in any significant way. It reminds one of the story about the utility executive who, upon deciding to commit suicide, threw himself in front of a glacier.

No matter what Disco may say, the former NB Power has been glacially slow in its approach to rate changes, particularly for the residential winter heating class and the all electric GS II class.

And as Mr. Coon alluded to this morning, maybe at that time it was appropriate policy to do that.

In fact as Nr. Larlee noted, although there is only one residential class, the reason Disco broke the residential class into heating and non-heating was to identify to the Board the disparity in the RC ratios, particularly with respect to the winter heating load. A disparity, which Dr. Rosenberg in his evidence, sought to narrow.

We do not believe, nor do we believe any Intervenor in this proceeding believes, that an issue as important as the proper rate designs for the new Disco can be left to the generic approach proffered by Disco.

If for any reason the Board believes that any of the matters it determines are appropriate should be phased in or that there should be caps put in place, then any such phase-in period or caps should be mandated in this proceeding as part of the generic determination on the go forward cost allocation and rate design.

Such a decision by this Board is perfectly appropriate in that separate proceedings on cost allocation and rate design certainly will not occur as regularly as revenue requirement proceedings.

That also brings us to the point that the Board has little control on when Disco may come back for another revenue requirement hearing, particularly considering the legislative ability for Disco to raise rates within the 3 percent cap.

Mr. Chair, Commissioners, you have a rare opportunity to lay out an appropriate process and timeline to institute your overall decisions with respect to cost allocation and rate design, rather than simply leaving it to the future discretion of Disco.

Further, you may recall in our cross examination of Mr. Marois, that the new construction market in New Brunswick continues to highly favour new electric home construction. And again, Mr. Coon alluded to that this morning, in that electric baseboards with their lower capital costs are an easy sell when combined with the declining block structure.

And that considering that any future decisions the customers make regarding a change in the source of winter heat are long term capital decisions, unless the Board signals clearly and directly in this decision that the declining block will disappear and the time frame for such, if the Board does not feel this can occur immediately, then the appropriate price signal will still fail to materialize in the minds of the consuming public for some time.

Identical considerations exist with respect to the elimination of the GS II class and the abandonment of any preference for all electric customers.

Now if I could briefly touch on the second issue, that of the standby rate. Dr. Rosenberg's proposal is that Disco be directed to institute a standby rate or rates for cogeneration based upon generally accepted and customary principles of rate design for that type of service.

In essence, he proposes a rate that features a daily prorated demand charge for generation and transmission costs in lieu of the normal demand charge. Distribution costs for those customers served with distribution voltage would continue to operate in the normal fashion and energy charges for standby service would be identical to full requirement service.

To again properly reflect the cost causation of such a customer, the demand charge would not be based on the peak demand for the month, but the peak demand for the day.

Disco's response to this appears to be that they have been and will continue to offer their interruptible rate in this regard, but that rate is simply not designed for this purpose.

Considering that the fostering of cogeneration is one of the goals of the New Brunswick energy policy and that the Market Design Committee made a specific recommendation intended to identify and eliminate barriers to the development of cogeneration, we see no reason why Disco would not wish to develop a rate that would properly reflect this type of service.

This would not be a substantive undertaking, and as such EGNB requests the Board to order Disco to develop such a rate to be brought back to the Board for consideration by it and interested parties.

Mr. Chair, I am now going on to the final issue of cost of service.

CHAIRMAN: Do you want to -- how long do you expect it would take to conclude?

MR. MACDOUGALL: Probably about as long as I have just been.

CHAIRMAN: So now might be an opportune time to break for lunch?

MR. MACDOUGALL: It would be ideal.

CHAIRMAN: Yes.

MR. MACDOUGALL: Thank you, Mr. Chair.

CHAIRMAN: Come back at quarter after 1:00.

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

CHAIRMAN: I presume there is nothing preliminary. Go ahead, Mr. MacDougall.

MR. MACDOUGALL: Thank you, Mr. Chair, Commissioners. Since we are going into the issue of cost of service, I hope that we all had a light lunch so that we can -- I will leave it at that.

CHAIRMAN: We would like another story like you had this morning, Mr. MacDougall.

MR. MACDOUGALL: We will see if we can get one in. I'm just not sure.

I would like now then to turn to the final issue dealt with by EGNB in this proceeding, that being cost of service. On this issue there appears to be more significant disagreement among the parties than with respect to the issue of rate design.

However, as the proceeding unfolded it became clear that the issues are quite discrete and some matters which appeared at the outset on first reading of the direct evidence as points of contention became in our view less recognizably so as the proceeding went on.

Although when delving into the depths of the minutia of cost of service studies one can reach quite a level of complexity, we believe the primary cost of service issues for resolution by this Board start at a much higher level, and that will be the focus of our remaining comments. We would ask the Board I guess and all parties to be careful not to miss the forest for the trees on this complicated issue.

As Dr. Rosenberg framed it and as Mr. Morrison referred to it this morning, the first issue is a threshold question, whether to look at the cost accounting approach, i.e., just look at how the costs are billed to Disco or should we take the cost causation approach? Mr. Knecht generally accepted that this was the threshold question as well, although in his evidence he considered it more of a policy question as to whether to accept the traditional approach, that being an approach such as fixed variable, or Equivalent Peaker, the PPA causation approach, what we have otherwise been generally been referring to as the billed proposal, or what he referred to as the market approximation approach, essentially an approximation of marginal costs, an approach which was also discussed in part by Messrs. Adelberg and Garwood.

Now to step back briefly, this issue centres around the appropriate approach primarily to generation fixed cost classification and allocation. And as the Board is aware, the reason this was the focus of much of the experts' reports is that generation fixed costs are a very substantial portion of the overall utility's costs. In other words, this is a big ticket item.

Now let us start with Disco. What is their approach? The real issue, as evidenced by the direct testimony of Dr. Rosenberg, Mr. Knecht and Messrs. Adelberg and Garwood, is that, one, they use the as billed approach for the Genco generation fixed costs. And, two, they then use the 40/60 split which is in our view is fundamentally based on the Peaker Credit Method which I will discuss below, with respect to the Nuco fixed costs. None of the Intervenor's experts agree with Disco's use of the as billed approach to the Genco fixed costs, which would have them classified as 100 percent demand.

Messrs. Adelberg and Garwood indicate that they would use the PPA costs, but they would apply the Peaker Credit Method. And I will get into this probably a little more tomorrow on reply, but just briefly in response to Mr. Morrison this morning, he indicated that they would use the PPA approach. That's not true. They note they are only accepting the PPA costs because they found them to be similar to the underlying accounting costs, but they did not accept the as billed approach to classification and allocation.

What does Dr. Rosenberg say about the as billed approach? Well he clearly comes down on the side of cost causation and notes Disco's ambiguity in using the as billed approach for the Genco PPA on the one hand, while on the other hand they treat the nuclear contract based on their view of the underlying cost drivers for the Point Lepreau facility. I commend the Board to Dr. Rosenberg's direct examination where he indicated eight reasons why he recommends the cost causation approach.

To highlight just a couple of these points as they relate to the as billed approach. One, although NB Power is an unbundled utility, it is an unbundled utility in name only. It looks and acts exactly like vertically integrated utilities that, as Dr. Rosenberg noted, he has dealt with for the past 24 years.

Secondly, ultimately the PPAs must reflect the physical engineering and economic realities of the underlying generation of Genco and Nuclearco. So why pretend that something else is governing these transactions.

Further he notes that the PPAs were not the result of a competitive procurement process.

I will not go into the specifics of Dr. Rosenberg's other reasons in detail but again commend them to the Board.

What does Mr. Knecht say? Well although he commends to the Board either the traditional approach or his so called market based approach, depending on the underlying policy decision, he specifically disavows use of the PPAs as in his words, they are not market based and appear to be relatively unstable.

And finally Messrs. Adelberg and Garwood. They note at pages 16 and 17 of their direct evidence, and this is a quote, "When it comes to other Genco costs, however, the company accepts the demand energy split implicitly reflected in the PPA pricing structure for all costs other than fixed OM&A, i.e., it treats all costs billed as capacity as demand related and all energy costs as energy related. This ignores the fact that some Genco capacity costs are energy related because they were incurred to secure lower energy costs than would result from relying on lowest cost capacity, i.e., peaking capacity. To be consistent, the company should have applied the Peaker Credit Method to the Genco fixed costs as well." And that's a direct quote from Messrs. Adelberg and Garwood's testimony.

Accordingly, to reflect underlying cost causation the experts for EGNB, the Board Staff and the Public Intervenor, all suggest that Disco's as billed approach to the Genco fixed costs is inappropriate in that it considers all of the costs as demand related.

I believe it is important for the Board to note that Dr. Rosenberg, as well as the experts for the Public Intervenor and Board Staff, agree that this change should occur. This is notwithstanding the fact that classifying all of Genco's fixed costs as 100 percent demand would drive proportionately more costs to the residential class and away from the large industrial class, because on average residentials have lower load factors than industrial classes. Despite this Dr. Rosenberg agreed with the other experts, that it should occur.

The overall effect of any change in methodology that allocates more costs to be recovered through energy charges and less through demand chargees is to allocate higher costs to the industrial class and lower costs to the residential class. As Mr. Adelberg confirmed, Dr. Rosenberg's approach does not suffer from the inconsistency inherent in Disco's approach.

What then are the remaining inconsistencies as between Dr. Rosenberg, Mr. Knecht and Messrs. Adelberg and Garwood? Well two issues of potential discrepancy remain. One, the proper approach to the capital for fuel and fuel for capital substitution in the Peaker Credit Method, and, two, the issue of the potential reflection of marginal costs in cost causation at this time.

In dealing with the issue of the capital for fuel and fuel for capital trade-off, let me begin by acknowledging that there appears to be some discrepancy that arose throughout the course of this proceeding with respect to the underlying basis of the 40/60 demand energy split ruled on by this Board in 1992. And I believe Mr. Morrison referenced that this morning.

Messrs. Adelberg and Garwood seem to suggest that this split should be used with no consideration of the underlying basis for the split. As we all know though, once ordered by the Board to provide a basis for this split, Reed Consulting and Mr. Ketchum provided evidence that this split was supported by the Peaker Credit Method, which method was updated with the best information in response to EGNB IR-36 in this proceeding, to reflect a similar 40/60 split.

Whether, as the Chair pointed out during the proceeding, this report has been adjudicated on or not, i.e., the Reed report, it is clear that the Peaker Credit Method is the only logical basis which supports the 40/60 split.

Reed put this forward as the approach appropriate for New Brunswick in 1994. Disco has utilized the split that is supported by this approach in the current proceeding with respect to the Nuco contract. Messrs. Adelberg and Garwood referenced their proposed application of the Peaker Credit Method and noted it reflected cost causation. Mr. Knecht refers to the traditional approach as being an approach such as the fixed variable or Equivalent Peaker, i.e., the Peaker Credit Method, and Dr. Rosenberg supports the use of the Peaker Credit Method for New Brunswick.

It appears from our reading of the record, whether the Reed report in 1994 was formally approved or not, the approach proffered therein and subsequently adopted by all parties in this proceeding, is the Peaker Credit Method.

As Mr. Adelberg said on cross examination, no party in this proceeding has rejected that method. In fact, with the exception of Mr. Knecht's market based approach, no other method has been put forward. I will get to the so-called market based approach later.

In short, Mr. Chair, Commissioners, if we discard the Peaker Credit theory we have no basis for the 40/60 split.

Now having rejected Disco's use of "as billed" method which charged the Genco fixed costs as 100 percent demand, Dr. Rosenberg then highlighted for the Board that the Peaker Credit Method is one of a host of methods known as capital substitution methods, and that the trade-off in a capital substitution method is not only one way; you either trade-off more capital for less fuel costs or you trade-off more fuel costs for less capital costs. There are two sides to the coin.

As such, Dr. Rosenberg, clearly noted that the NARUC manual specifically recognizes the flip side of the capital substitution approach when he indicated that the Equivalent Peaker Classification method applied in the manual, and as applied by Reed, ignores the fuel savings that accrue from running a base load unit rather than a peaker. Dr. Rosenberg also points out that the symmetrical corollary on fuel cost allocation has been recognized by the Public Utility Commission of Texas. And if could quote from that case and this was a reference in Dr. Rosenberg's evidence.

"The Examiner's find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal in that case, the high load factor classes, which will bear higher cost responsibility for base load units will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units."

This Mr. Chair, Commissioners is exactly the situation that we will face here in New Brunswick, to the unwarranted detriment of the high load factor industrial class, if this fuel symmetry is not recognized.

As was clear from the proceeding with no parties disagreeing, system planners when designing systems, including the NB Power system, aim to reduce overall costs, not just capital costs.

Dr. Rosenberg therefore carried out a breakeven analysis which recognized the flip side of the capital for fuel substitution approach. In the context of the New Brunswick system, this approach is much more fully cost based than ignoring the breakeven analysis altogether. Again, EGNB's suggested approach is to ensure that in both cost causation and rate design, cost drivers are recognized and costs classified and allocated to the appropriate customer classes based on their cost causative characteristics, such as their load factor and impact on the system's load profile.

As specifically noted by Dr. Rosenberg in his redirect and in his response to interrogatory 2 from the PUB staff, the primary reason why there are not multiple examples of his breakeven analysis with respect to the use of the Peaker Credit Method, is that most jurisdictions in North America utilize other approaches to cost classification, and so have implicitly rejected the type of one-sided treatment of the fuel capital and capital fuel trade-offs typified in the Disco study.

Based on the support for the Board-approved 40/60 demand energy split provided in the Reed Report, and Dr. Rosenberg's own review of Disco's evidence regarding its system planning and cost drivers, Dr. Rosenberg saw no reason to deviate from the Peaker Credit Method which supported the 40/60 split, with the exception that it should for all of the reasons noted above recognize the flip slide of the coin in the capital for fuel trade-off. With this revision, Dr. Rosenberg believes that the Peaker Credit Method is an appropriate approach for New Brunswick.

Now, Mr. Chair, Commissioners, I found it very interesting to note that in the extract from the Board's April 23rd 1993 decision on NB Power's rates, which was referred to Dr. Rosenberg by Mr. MacNutt, at page 22, the Board specifically stated in that decision, "The Board will welcome proposals which can be shown to enhance the accuracy of cost of service results, either as part of NB Power's pending review and report on methodology or at any other time." This is exactly what Dr. Rosenberg has done. Not only does Dr. Rosenberg's study correct for the inherent ambiguity in Disco's study, but it goes on to more appropriately reflect NB Power's system planning and the cost drivers of Disco's current system, which will form the underlying basis for the costs for the provision of electricity in New Brunswick and to New Brunswick consumers for some time to come.

At this point, we note that Messrs. Adelberg and Garwood in their oral rebuttal evidence appeared to take issue with Dr. Rosenberg's proposal. I believe it is important that we highlight what occurred on cross examination of these gentlemen in this regard. First, with the greatest of respect to their qualifications in utility practices in general, it is very clear that they have limited, if any, experience with fully allocated class cost of service studies. This was in marked contrast to Mr. Ketchum's and Dr. Rosenberg's experience, as well as even that of Mr. Knecht.

With respect to the specifics of their comments, they indicated in their rebuttal that Dr. Rosenberg's proposal resulted in a cost shift, in their words, of certain dollars. However, one can only have a cost shift if one is shifting from an agreed upon base. Yet all of the experts agree that Disco's approach to the Genco fixed costs is incorrect.

Whose CCAS are we shifting from? Dr. Rosenberg developed what he feels is the most appropriate CCAS for New Brunswick. Admittedly saying no cost allocation study is perfect.

In fact, as we discussed, his first step was to correct for the discrepancy in application of the "as billed" figures to the Genco fixed costs, the same discrepancy noted by Messrs. Adelberg and Garwood themselves, and Mr. Knecht.

Had he, and this is very important, not corrected for this, he would have shown no cost shift in the regard from the Disco CCAS, but he would have been in disagreement with Messrs. Adelberg, Garwood and Knecht on the more fundamental point.

Just briefly on Messrs. Adelberg and Garwood's specific rebuttal points. One of the so-called cost shifts, to the extent of $2.3 million, was Dr. Rosenberg's approach to the export credit. But as Mr. Adelberg confirmed, this was the exact same approach, having the exact same dollar impact, as suggested by himself and Mr. Garwood in their evidence. We note that this treatment of the export credit is again more in line with cost causality than that of Disco's and commended to the Board.

They took issue with Dr. Rosenberg's approach to the hydro facilities, but Dr. Rosenberg had already confirmed on cross examination that if the Board wished to treat the hydro facilities differently he could see this as a potential modification to his approach, in that it was difficult to evaluate hydro facilities in a breakeven analysis due to their run of river nature.

3. With respect to his use of monthly date it was pointed out that absent the hourly load data for all classes, which is simply not available, Dr. Rosenberg was

using the monthly energy usage by class, information that was available, as an appropriate proxy for the breakeven point between the combined cycle plant and a coal plant.

And the final point made by Messrs. Adelberg and Garwood was that Dr. Rosenberg had not strictly applied the 40/60 split to each type of fuel usage, i.e. hydro, coal/orimulsion, oil/gas. Dr. Rosenberg applied the Peaker Credit Method to the various classed of generation by fuel type in the exact manner that the Peaker Credit Method is traditionally utilized and as identified in the NARUC manual.

As noted in his response to the undertaking from Board Staff, exhibit EGNB-3, that merely -- in that undertaking -- that merely applied the 40/60 split, he does not believe that such a cost study faithfully reflects the Peaker Credit Method. Therefore, although requested to respond to the undertaking, the undertaking has respectfully no regulatory or economic foundation.

This is presumably exactly why in accepting the 40/60 split in 1992 decision, the Board then required the NB Power to "prepare a comprehensive study supporting the 40/60 split both on a current and future basis." The Board was not satisfied with the split per se. They wanted a cost justification, which is and remains the

Peaker Credit Method.

Mr. Chair, not to go on the last issue, and that is the issue of marginal cost.

CHAIRMAN: Want a Fishermens' Friend, Mr. MacDougall?

MR. MACDOUGALL: No, I think I am okay.

CHAIRMAN: Are you sure?

MR. MACDOUGALL: Thank you. I appreciate it.

CHAIRMAN: We have got lots of them.

MR. MACDOUGALL: I think a little water will get me through. Thank you, very much.

Now to start with, we note that neither of the proponents of the potential use of marginal costs, Mr. Knecht and Messrs. Adelberg and Garwood, have filed a full marginal cost study in this hearing. In fact, they both acknowledge that the information required to do so is not presently available.

Mr. Knecht recommends that if the Board makes a policy decision that his so-called market-based approach is deemed to be preferable, that the Board direct Disco to upgrade its load research and to file a cost study based primarily on marginal system costs applied to hourly class load information, at its next general rate hearing. In fact, he notes that even if the market-based approach is deemed preferable in the interim, the traditional approach is best retained.

Furthermore, Mr. Knecht acknowledged on cross examination that he was using average on-peak and off-peak marginal costs for comparison, but that in a marginal cost study you would look at marginal costs in each hour, you would not look at average costs.

He also recognized that there was a significant differential in NB Power's marginal costs between the lowest marginal cost and highest marginal cost hours as indicated in his own figure IEc-2, which is in the confidential portion of his direct evidence.

With respect to Messrs. Adelberg and Garwood, they recommended that the Board may wish to pursue this issue further and they flesh that out somewhat in their -- on cross examination.

It is interesting to note, however, that as pointed out on cross-examination of Mr. Adelberg and Mr. Garwood, there has been no rush to adopt marginal cost of service studies by regulatory commissions since the early 1990s.

Now the final issue with respect to marginal costs is the issue of their reflection of the market. The problem is Mr. Chair, Commissioners, that what we have in New Brunswick is a far cry from a market. In fact, although we have a de jure market, as referred to this morning by

Mr. Morrison, and although limited to the large industrials and municipals, we have no de facto market or any indication of one developing in the near future. And I believe Mr. Plante alluded to that this morning as well.

As both Dr. Rosenberg and Mr. Adelberg indicated throughout the proceeding they both became aware that there is not even yet a stranded cost or exit fee methodology set in New Brunswick, and that this in and of itself is a significant impediment to a market.

Furthermore Disco has entered into longterm power purchase agreements tied to Heritage Assets. Disco by its own admission states that there is no requirement for new capacity until 2014 or '15, and with the exception of some non-dispatchable wind energy that may become a part of the generation mix over the next number of years, it is unlikely that there will be any significant market developed for dispatchable generation in New Brunswick.

We also commend you to Mr. Hyslop's cross examination of Mr. Marois regarding the status of the pre-requisites that Navigant Consulting felt were required for a functioning New Brunswick electricity market.

The use of marginal based or market based approaches is simply premature for New Brunswick at this time.

EGNB respectfully submits that the record clearly indicates that the priorities should be, one, to reflect the existing costs of NB Power appropriately to the rate classes, i.e., to recognize that the Heritage generation assets of Genco are the drivers to these costs. Two, that both sides of the capital fuel trade off need to be recognized in the cost study related to theses costs. And three, that rate designs such as those that we have previously referenced, be instituted in order to send each rate class the appropriate price signal and to encourage the efficient use of energy resources and conservation.

We would also note that adopting such an approach would have the added benefit of being consistent with the goals of protection of the environment as related to energy usage and with the goals of the White Paper on energy efficiency and the newly formed Energy Efficiency Agency.

Mr. Chair, Commissioners, to close, the approach EGNB commends to you, and as supported by Dr. Rosenberg and in large part by others in this proceeding, is one of cost causation.

EGNB believes this is an appropriate approach for Disco considering the current state of the electricity market in New Brunswick at this time. Until customer classes are fully aware of the costs that their electricity usage is placing on the system and seeing price signals that reflect those costs, we will simply not have as efficient an electric supply system as we could. As well we will not have a level playing field which will ensure that the appropriate energy choices are made by the energy consuming public in the province.

In closing, we believe the Board is in a fortunate position in this proceeding in that having heard the evidence we believe that common sense, practicality and sound economics all point you in the same direction as to your ultimate findings.

Thank you very much for the opportunity to make this presentation.

CHAIRMAN: Thank you, Mr. MacDougall.

MR. MACDOUGALL: And, Mr. Chair, I have the hard copies that I have stuck to. I might not have said -- I might have added a few words throughout but there is nothing in there that wasn't said. So it's -- I commend it to you.

CHAIRMAN: Appreciate that. Thank you.

MR. MACDOUGALL: I apologize, I didn't have a second joke for the second part.

CHAIRMAN: Now this morning the Irving group were not represented. Is that the case this afternoon? Okay. And Jolly Farmer is not represented. Rogers Cable was not represented. The Self-represented Individuals were not represented. But the Municipalities were.

MR. GORMAN: That's correct.

CHAIRMAN: Would you come forward, Mr. Gorman?

MR. GORMAN: Thank you.

CHAIRMAN: And what time would you put on your trial record, Mr. Gorman?

MR. GORMAN: How about 22-and-a-half minutes.

CHAIRMAN: Okay.

MR. GORMAN: Before I commence, just for the record I did indicate this morning when we were taking appearances that some individuals were not here but would be joining us. And since that time Richard Burpee from Saint John Energy has joined the proceedings, Charles Marden and Michael Couturier from Edmundston Energy is also here and Dan Dionne from Perth-Andover Electric Light Commission. I also have hard copies of my presentation and they can be made available to the Board at this stage or when I'm finished, whatever the Chair wishes. I can hand them out now or --

CHAIRMAN: Never share them in advance, Mr. Gorman. Then we would just be flipping.

MR. GORMAN: You never know what you might want to take out either.

Well good afternoon, Mr. Chairman and Commissioners. As you know, I represent the New Brunswick Municipal Electric Utilities, namely Energy Edmundston, Perth-Andover Electric Light Commission and Saint John Energy.

I have been in attendance together with several representatives of the three Municipal Utilities throughout this entire hearing and would like to begin our presentation by thanking the Chairman and Commissioners for the opportunity to participate in this process as an Intervenor and to present our position on various issues arising out of the cost allocation and rate design portion of this rate application by NB Disco. Your patience and attendance to the witnesses is appreciated through the many days of these hearings.

The three Municipal Utilities became Formal Intervenors in this proceeding for the purpose of addressing the implications of this application to their customers, the ratepayers of our communities. The implications of your decision will of course affect all of the ratepayers in New Brunswick.

We believe that the governing principle for the Board in determining the outcome of this proceeding is set out in section 101-5 of the Electricity Act which states of course that the Board at the conclusion of these hearings shall approve the charges, rates and tolls if satisfied that they are just and reasonable, or if not so satisfied, fix such other charges, rates or tolls as it finds to be just and reasonable.

The Municipal Utilities fully support that ideal and are greatly concerned about the negative impact that an unreasonable or unjust cost allocation or rate design might have on their customers, residential, commercial, institutional or general service, and industrial.

The primary issues raised by the Municipal Utilities during these hearings which occurred over the past couple of months and the ones which would affect them the greatest include the following, a) the allocation of New Brunswick Power Holding Corporation, or Holdco, and Disco administrative costs and allocation of regulatory costs to the wholesale class. And our second issue is the appropriateness of Disco's decision to set a target revenue to cost ratio of 1.05 for the wholesale class.

In addition to those issues, other matters were raised during the course of the hearing which would affect the Municipal Utilities and I'm going to make just a very brief statement on a couple of those issues and I won't have anything further to say other than my introductory comments.

The first of those is billing on a non-coincident peak basis versus coincident peak basis. This issue was raised I believe by Mr. MacNutt in cross examination of the Disco panel. At that time Mr. Larlee testified that Transco doesn't have sufficient metering at Disco substations to allow billing on a coincident peak basis.

We would favour a move in the direction of installation of appropriate metering at all transmission supply points to allow for billing on a coincident peak basis. We didn't lead any evidence on that point nor did we cross examine on it. So those would be our remarks.

The second issue that we will make some very brief remarks on are seasonal and time of use rates. And again we didn't lead any evidence on those points, nor did we cross examine on those points, but would make the following statement. After hearing the extensive discussion on this subject at these hearings, we would recommend that if the Board is considering directing Disco to implement seasonal or time of use rates, that such implementation be applied to all rate classes rather than on a selective basis.

We also recommend that any price differentials on a seasonal or time of day basis be supported by appropriate cost studies.

I will now move to I guess my argument or summation with respect to the two main issues that I have identified.

The costs incurred by Disco in serving its customers must be recovered from those who receive service. The purpose of this hearing is to review how Disco proposes to assign theses costs.

The Municipal Utilities accept the principle that costs would be shared amongst customers on the basis of cost causation. This means to us that the actual cost of serving each customer class should be recovered from that customer class. In other words, Disco should not seek to either under recover or over recover its costs of serving a particular customer class.

Disco has grouped its customers into rate classes with similar characteristics of electricity use in order to establish rates for each class. A class cost allocation study was prepared by Mr. Larlee which established eight rate classes and those were residential, general service I, the standard, general service II, the all electric, streetlights and unmetered, water heaters, small industrial, large industrial and wholesale.

The customer grouping as presented by Disco does not point out the fact that of the industrial classes, both small and large, some are served by Disco's distribution system and some from the transmission system. These industrial customers served directly from the transmission system. And this is information taken from Disco's evidence, 33 large and five small, according to schedule 6.0 of the CCAS found in exhibit A-3, and the two wholesale customers in our view are the transmission customers of Disco. The remaining industrial customers and all of the other customer classes are retail customers of Disco's distribution system.

Disco's distribution system can therefore be considered as a distributor serving a mix of residential, general service and industrial loads, just as the Municipal Utilities receive generation and transmission services at the wholesale level in order to serve residential, general service and industrial customers on their distribution systems.

NB Power's transmission system can therefore be considered to serve three wholesale entities, Saint John Energy, Energy Edmundston and Disco's distribution system as well as the transmission industrial customers.

The evidence at the hearing established that Disco proposed to charge large industrials using a revenue to cost ratio of .95, wholesale using a revenue to cost ratio of 1.05 and Disco Retail, the remaining classes, at a revenue to cost ratio of 1.015.

For reasons that will be set out later in our summation, it is submitted that the principles of reasonableness and fairness would dictate that all three transmission classes should have target revenue to cost ratio of unity, i.e., a revenue to cost ratio of one. Before elaborating on this issue I will first deal with the cost allocation issue.

So the first issue that I am going to deal with in detail is the allocation of the NB Power Holding Corporation and Disco administrative costs, including regulatory costs, to the wholesale class.

One of the expenses that needs to be divided amongst the rate groups are the general office and administrative costs. In the CCAS submitted by Disco, their proposed methodology of dealing with theses costs is shown in addendum III. And you will recall the other day in fact we circulated a re-stated addendum III.

The cost functions to be allocated include primarily administrative and general expenses which typically cannot be directly categorized as demand, energy or customer related. As you will have seen from addendum III, for the majority of these costs, Disco is proposing an allocation based on revenue, or a combination of some other base with revenue.

It is noteworthy that for regulatory costs within Disco and Holdco, Disco is proposing that equal shares be allocated to each of Disco distribution, wholesale and industrial transmission classes, i.e., one-third to each of the transmission customers. This allocation seems unreasonable on the face of it with the Municipal Utilities accounting for only ten percent or less of Disco's revenue, and even less on the basis of allocated cost.

The Municipal Utilities presented expert evidence on this point from Paula Zarnett, Vice-President of Barker, Dunn & Rossi, a leading management consulting firm specializing in advising the North American and international electricity industry on matters related to electricity markets.

Ms. Zarnett, in her evidence, states that for a widely accepted industry standard in the allocation of administrative and general expenses, it would be appropriate to refer to the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners, commonly referred to in these hearings as the NARUC Manual.

That manual was cited as an authority by more than one expert witness at this hearing, including Mr. Ketchum on behalf of Disco. In cross examination Mr. Ketchum acknowledged the general acceptance of the NARUC manual stating at page 984, line 19, "And I have quoted it, the NARUC Manual, from time to time in my testimony and evidence." Then there was a Question, "And I have no doubt that you are aware of other experts and have heard them refer to it and rely on it." And Mr. Ketchum's answer is, "That is correct, sir."

NARUC proposes that regulatory commission costs be allocated on the basis of operating expenses, net of fuel costs and purchased power.

Disco proposes to allocate regulatory costs totalling some $2,378,000 as one-third to each of Disco, wholesale and industrial transmission. It is submitted that this is not a fair approach because it does not reflect any readily apparent driver of regulatory activity and does not result in an equitable allocation of the costs.

Ms. Zarnett reviewed five options and concluded that the use of total allocated costs is a simple method producing a more equitable result than the one-third approach, and is reasonable also at a conceptual methodology level.

Since the Board scrutinizes all costs

as part of this proceeding, it is reasonable to include all costs in the allocation base.

You will recall that this issue was discussed during the cross examination of Disco's panel. Their panel was unable to justify the one-third allocation on any principles found in the NARUC manual or otherwise, and put forward the participation of the wholesale class in this hearing -- sorry -- in regulatory hearings -- as their only explanation for the allocation.

This explanation was provided by Mr. Larlee and can be found at page 976, line 15 of the transcript where he stated -- and this is a quote -- "My rationale for not using revenue in this case is simply that historically in these proceedings there have been three major groups involved, distribution customers, wholesale customers through the Municipal Utilities Association or representing the actual utilities themselves, and the transmission customers, usually represented by the large industrial customers. So I felt it was a reasonable approach to simply divide the costs into three."

The Municipal Utilities are somewhat concerned with the rationale set forth by Disco on this issue.

Mr. Larlee then was asked to perform a calculation to determine the level of assessment that would be indicated through the use of sales revenue, which was the allocator most frequently used by Disco for all other administrative costs, and he testified that it would be approximately ten percent rather than the 33 percent as allocated.

As a result, the Municipal Utilities would request that the Board order the following with respect to cost allocation, a) that total allocated costs be used as an allocation base for regulatory costs, and, b) that those general and Holdco costs which were proposed by Disco to be allocated based on sales revenue, instead be allocated on the basis of all other allocated costs.

And by the way, if -- and I will get into revenue to cost ratio, but if revenue to cost ratio was at unity, there would be no difference between the two methods.

Ms. Zarnett has prepared a computation adjusting the total allocation of costs for distribution, transmission industrial and wholesale customer groupings that would result from making the two changes that I have just suggested. These results are in the same form as Disco's addendum III and are found at table 3 in Ms. Zarnett's report. This was entered as exhibit UM-1 and of course this table was revised and it's also found I believe in EGNB Interrogatory UM-12 -- IR-12, I'm sorry -- but I have also attached a copy of that table to the written version of this submission.

If the Board were to accept this more reasonable approach to the costs set out in addendum III the wholesale class would achieve a savings of somewhere in the neighbourhood of $667,000.

Although Disco's panel expressed the opinion that this number was relatively insignificant when considered in context of the overall costs, I can assure the Board that it is not insignificant to the Municipal Utilities nor to the customers that they serve.

The second issue addressed during these proceedings by the Municipal Utilities dealt with the appropriateness of Disco's decision to set a target revenue to cost ratio of 1.05 to the wholesale class.

And as you know, Disco has proposed that the wholesale customer class contribute based on a ratio of revenue to cost of 1.05. As discussed earlier, there are two other transmission classes, namely Industrial with a target revenue to cost ratio of .95, and Disco distribution with a target revenue to cost ratio of 1.015. The target revenue to cost ratios for the industrial and wholesale customers are explicitly set out in Disco's application but the revenue to cost ratio of Disco's customers is a computed number found at table 5 of Ms. Zarnett's report.

A copy of that Table I guess was intended to be attached to this submission, I'm not sure that it is. But in any event it's found at table 5 to UM-1. A copy of -- the Board might recall on this issue Mr. Larlee calculating that ratio during cross examination and confirming its accuracy. This can be found at page 1006, line 18, of the evidence. In his cross-examination Mr. Larlee responded as follows, "But in terms of the question that has been posed to you, if you were to calculate the revenue cost ratio for the same -- effectively the same set of customers, Disco's comes at 1.015, you would agree with that? You have agreed with the math.? Mr. Larlee answered, "Yes, I have."

It is noted that the retail customer classes that are served by Disco, namely residential, general service I and II, small and large industrial, streetlights and unmetered and waterheaters, are the same customer classes served by the Municipal Utilities who purchase power from Disco at the wholesale rate.

The wide gap between the target revenue to cost ratios of the three transmission classes, .95 to 1.05, stands in contrast to the equal treatment of the three transmission classes proposed by Disco when it was allocating regulatory costs.

The only rational for targeting wholesale customers at a revenue to cost ratio of 1.05 put forward by Disco at these hearings is the language found in contracts between NB Power and two of the Municipal Utilities, namely Energy Edmundston and Saint John Energy. It is noted that the contract language is different for each of these utilities with the Energy Edmundston contract referring to revenue to cost ratio of 1.05, whereas the Saint John Energy contract refers to a revenue to cost ratio of no more than 1.05, thus implying that it could be less than 1.05. It is also noted that t here is at present no contract with Perth-Andover but they are obviously a potential wholesale customer.

It is our submission that the intent of this contract language, which was drafted a number of years ago when NB Power was an integrated utility, was to provide a commitment from NB Power, as it then was, that the revenue to cost ratio would be reduced to 1.05 or below from the level of 1.12 or higher which prevailed between 1988 and 1996.

This is consistent with the 1992 CARD decision rendered by this Board and the principle of gradualism. It is submitted that the existence of contract language that differs between the contracts with two Municipal

Utilities can hardly be used as justification for establishing a revenue to cost ratio above unity for the entire wholesale class.

If this were allowed it would effectively usurp the function of this Board which is set out in section 101(5) of the Electricity Act, and I cited that section at the commencement, so I won't cite it again. But obviously that's the section that grants jurisdiction to this Board to set -- or to approve -- sorry -- charges, rates and tolls.

And as recently as last month the Board in dealing with a Rogers Communication matter concluded that it did have jurisdiction to approve rates for pole attachments even when the argument was made it should be a matter of contract.

The contracts negotiated by the Municipal Utilities with NB Power were in our view primarily intended to deal with a number of technical and operational aspects of their relationship and were not intended to supersede the jurisdiction of the Public Utilities Board with respect to the setting of rates to be charged for electricity. It is specifically stated in section 3.1 of the Saint John Energy contract, and I quote, "at such rates and upon such terms and conditions as are established by NB Power from time to time, and published in NB Power's Rate Schedules & Policies Manual for customers in the wholesale classification." And in section F, subsection 2 of the Energy Edmundston contract, effective July 1st, 1997, the rate shall be the rate for Wholesale Customers with longterm Contracts as set out in NB Power's Rate Schedules and Policies Manual.

As stated earlier, the Municipal Utilities believe that the reference to 1.05 in the aforesaid contracts was no more than an acknowledgement of the 1992 CARD decision of this Board which stated at page 27, and I quote, "The Board also expects NB Power to develop a plan to move all classes within the approved range of .95 to 1.05 over a period of time which will permit proper consideration of the desire to avoid rate shock."

In support of our position, the Municipal Utilities rely on the case of Nova Scotia Board of Commissioners of Public Utilities versus Nova Scotia Power Corporation et al, 1976 N.S.J. No. 505, and I have a copy of that available for distribution. I am going to deal with that case. Would the Board like me to distribute it now or just give the quotes and distribute the case after my submission?

CHAIRMAN: Distribute the case after.

MR. GORMAN: Thank you. The Public Utilities Board in that case posed the following question to the Appeal Court by way of stated case. "Assuming compliance with the applicable procedural provisions of the Public Utilities Act, has the Board of Commissioners of Public Utilities jurisdiction to approve, disapprove, modify, amend, alter, reduce, increase, cancel or make substitution for the rates, tolls, charges or schedules contained in each of the contracts reproduced in the Appeal Book and forming part of this Stated Case."

At paragraph 54 of the decision the Court stated, "I find support for my interpretation of the effect on prior contracts of the supplier becoming a pubic utility, in the overwhelming authority of American cases based on basically similar public utility legislation. The main principles expressed in Corpus Juris Secundum as follows:

Unless otherwise provided by constitution or statute, a general grant of power to regulate rates authorizes a public utility commission to regulate or modify rates fixed by contract, including those specified in franchise agreements, even though some contracts or agreements were executed prior to the passage of the statute by which power is conferred."

In concluding that the question posed should be answered in the affirmative, the Board -- sorry -- the Court stated at -- and that's a correction I guess to my printed version -- it should read, the Court stated at page 60, "I conclude that the Board has the power and the duty to deal with the rates, tolls, charges or schedules charged by the Power Corporation to the municipal bodies and companies with whom it has the respective subject contracts, and that the question asked by the stated case should be answered in the affirmative."

I would also refer this Board to -- not a recent case. It's R. versus the Board of commissioners of Public Utilities, ex p the Town of Milltown -- I guess that would now be the Town of St. Stephen/Milltown -- a 1919 case found at 47 DLR 219. That was a New Brunswick Court of Appeal decision. And in that case the Court -- and I believe it was obiter dicta but by dicta suggested that if a contract had been renewed prior to the coming into force of the Public Utilities Act the Board would have had jurisdiction to modify it.

In interrogatories and on cross examination Disco was asked what policy provisions they relied on in setting a considerably higher target rate for the wholesale class than for the other two transmission classes. The consistent answer was that it was a matter of contract.

No policy considerations were put forward by Disco to justify targeting a revenue to cost ratio for the wholesale class that is considerably higher than that for the other two transmission classes.

As the Municipal Utilities believe that the Board has full jurisdiction to establish rates for all classes of Disco's customers, the issue remains as to the equity of the revenue to cost ratios applied to the three transmission classes -- customer classes. This entails two issues, the appropriateness of the revenue to cost ratio proposed for the transmission industrial class and the equitable treatment of all distribution utilities with respect to one another.

With respect to the industrial customers, any favourable treatment should be justified on the basis of some legitimate policy consideration. It should be demonstrated that a benefit accrues to the system as a whole and that any favourable treatment of the industrial class would be fair and equitable to all customers. No credible evidence to that effect has been provided to this hearing.

On this issue, Disco claims that there is no subsidy being given to the large industrial class because the target revenue to cost ratio falls within the prescribed bandwidth of .95 to 1.05. In the 2001 White Paper under the heading of "Cross-Subsidization" in the Current Rate Structure the White Paper states, and I quote, "The Province will direct the Crown utility to eliminate, over time, cross-subsidization between customer classes." And I acknowledge that that quote goes on and does mention the bandwidth, but the intention of the White Paper was to eliminate cross-subsidization.

In our opinion setting a target revenue to cost ratio at .95 without any policy consideration is a subsidy by any other name. The uncontradicted evidence at this hearing demonstrates that the industrial class at the proposed rates would underpay the cost of its electricity by approximately $15 million.

With respect to relative equity among distribution utilities, the reorganization of NB Power has created an industry structure consisting of a transmission system and four distribution utilities, namely Saint John Energy, Energy Edmundston, Perth-Andover Electric Light Commission and NB Power Distribution and Customer Service Corporation.

The information provided in the CCAS allows the Board to aggregate the distribution retail customers of Disco to show how Disco is proposing to treat its own distribution utility as contrasted with the treatment of the two arms-length distribution utilities it serves.

Computations showing how the information in the CCAS can be used to compute an aggregate revenue to cost ratio for Disco's distribution customers of 1.015 again can be found at table 5 of exhibit UM-1, while the wholesale class is being proposed to be set at 1.05.

The Municipal Utilities strongly believe that they should be placed on an equal basis with Disco retail and this can be achieved by reducing the wholesale class target revenue to cost ratio to the same as that of Disco retail, that is 1.015.

The end users served by the Municipal Utilities comprise residential, general service and distribution industrial customers in New Brunswick who have contributed through rates to the system over the years in the same manner as the residential, general service and distribution industrial customers of Disco have done. Therefore, having identical revenue to cost ratio for these distributors would be a fair and equitable result.

The Board should be careful not to compare the revenue to cost ratios for all of the sub-classes of Disco retail with the wholesale and industrial classes. The Board is reminded that the various sub-classes of Disco retail also exist within wholesale and that, although the mix of customers inevitably will be different, the customer classes are essentially the same. The fair comparison in our view is between the transmission customers, that is, Disco retail, industrial and wholesale, and we would submit that the Board's directive should be to put all of these classes at unity or at least Disco retail and the wholesale class at the same revenue to cost ratio.

It is our position that at a minium wholesale customers should be on a level playing field with NB Power Distribution's distribution customers in aggregate.

Possible alternatives could include implementing the revenue to cost ratio for distribution customers as proposed by Disco and increasing the contribution of industrial customers or adjusting the revenue to cost ratios of all three groups. Ideally all three groups should have revenue to cost ratios of unity.

Experts at the hearing testified that the cost allocation and rate design studies are not 100 percent accurate. And I believe that a couple of the presenters have already mentioned that fact. But in our view this provides more reason to move towards unity and not intentionally set rates at the extremes just because they exist. In such a situation it would be very easy for the rates to fall outside of the range and in our view the target should always be to move towards unity, not away from it.

The Board will recall the testimony of Mr. Adelberg of Energy Advisors. In referring to the principles of equity that the parties tried to achieve, he used a bit of a colourful expression to describe equity as, I cut the cake, you get to pick the piece you want. And I think that described very well what we are talking about, that all of the pieces should be essentially the same. And his evidence you recall was speaking of the elimination of cross-subsidies amongst the classes.

So, Mr. Chairman and Members of the Public Utilities Board, as a result of the foregoing the Municipal Utilities would make the following recommendations.

Firstly, allocations of regulatory costs should be based on total allocated costs representing an allocation base that is simple, fair and equitable.

Secondly, that other general and Holdco costs should be allocated using the aggregate of all other allocated costs. Choosing the aggregate of all other allocated costs has been the most reasonable and simplest approach.

And thirdly, the revenue to cost ratio of the three transmission classes should be set at unity or, in the alternative, the revenue to cost ratio for the wholesale class and for Disco retail customer class should be identical.

Again I would like to thank the Chairman and Commissioners for their patience and attention throughout these hearings.

CHAIRMAN: Thank you, Mr. Gorman. Not bad. You were ten minutes over. We will take our break.

(Recess)

CHAIRMAN: All right. Mr. Hyslop, what's your estimate?

MR. HYSLOP: 31 minutes.

CHAIRMAN: I will hold you to it.

MR. HYSLOP: I don't think it will be very much over that, Mr. Chair.

CHAIRMAN: Good. Thanks. Go ahead, sir.

MR. HYSLOP: Thank you very much, Mr. Chairman and Commissioners. Again, I would reiterate the comments of some of my predecessors. I thank the Board for the opportunity to be here today, to make these submissions, and for the time you have taken to hear a lot of evidence, a few motions, a few difficult issues, but you have worked very hard.

And I would also like just to take a moment to put on the record and acknowledge the efforts of the Applicant's employees. The interrogatory process, and I know I was part of it, but we made it pretty gruelling for these people over the summer. There is a lot of people that worked on the interrogatories, who have young families, and they did sacrifice their time to make this process go forward and I think it's proper to note that.

And in terms of regulatory affairs, I am probably the junior counsel here and I do take the opportunity to thank all my colleagues for their good spirits and professionalism throughout.

I hope as a group, we have made the issues such that the Board is aware of where the differences are and what the decisions are. So I like to put those acknowledgements on the record at first.

There is two or three issues that I am going to talk about. And they are much the same as my predecessors, those who have argued today. I want to talk about cost allocation methodology and in particular fixed generation costs, something about transmission costs, something about distribution costs, talk a little bit about rate design. And in particular I will talk about the residential declining block structure, GS II class, and I am also going to speak about something a little new, which is the creation of a separate class for the interruptible and surplus sales.

And the third thing I want to speak about will be the issue of load research. We want to -- we want this Board to consider in particular a load research program that is comprehensive in its scope and ongoing in its nature.

I do and have been working on a legal brief, which I hope to file with this court by Friday. My articling student is away at Bar Admissions, and although I promised to get the last draft done, I am a little remiss in that, but by the weekend she will be back to help me and this will be just on a couple of legal points.

We are going to encourage this Board to make ancillary orders that require the Applicant to complete certain research to assist this Board in the future. This will focus on load research for all classes. And although we acknowledge this is a rate hearing, it is our submission that the Act as a whole, together with the scope of judicial deference which is accorded specialized administrative boards by common law developments, this Board can use a broad discretion and make ancillary orders which are in keeping with the "public interest".

And we think the need for better information, the next time we are here, is important and in the public interest.

In this regard we will refer to a recent Supreme Court of Canada case, the Attorney General v. P.S.A.C., and I won't bore you with the details, but it does -- it suggests that Boards can make orders that are ancillary to its basic purpose.

And if your purpose is to design rates and create rates and establish rates, we submit that it is certainly ancillary to make sure you have good information as we go forward to make those decisions.

Now the second little legal issue we want to address and although I think --

CHAIRMAN: Is that all the coverage you are going to give that, Mr. Hyslop?

MR. HYSLOP: On the information?

CHAIRMAN: On the ancillary order, on load research and metering? It isn't? Okay. Fine.

MR. HYSLOP: Yes. Well at the end I am going to be very specific what I want, Mr Chair.

CHAIRMAN: Great. Okay. I will save it till then.

MR. HYSLOP: The very best. Now the second little issue is, you know, where does the Board stand in terms of directing itself in deciding what is the proper cost allocation methodology that it should use? And there is nothing in the Electricity Act says you have to use a certain methodology, so you are limited by we would suggest that law by the standards of reasonableness.

And I read -- just to give you some comfort on this, Mr. Chair and Commissioners, in a recent case in Alberta, Atco Gas and Pipeline (2005), the Court of Appeal said and I quote, because it's a wonderful quote for you, "the discretion to determine what is just and reasonable includes the discretion to define justness and reasonableness." So I think you get the picture.

CHAIRMAN: I read that every night before I go to bed.

MR. HYSLOP: I would hope it's on a mantle over your desk, Mr. Chair. In any event, with that in mind, that case follows a Newfoundland Court of Appeal case, and that case says -- and I am quoting from the Newfoundland Court of Appeal case, which is re Section 101 of the Public Utilities Act 1998. "The Board therefore has a broad discretion to adopt appropriate methodologies for the calculation of allowable rates of return so long as the methodologies chosen are not inconsistent with generally accepted sound public utility practices and purpose and policies of this Act and can be supported by the available opinion evidence, the determination of what constitutes a just and reasonable return..will generally be given the province by the Board and not normally interfered with."

Now perhaps dealing a little more specifically with cost allocation, Goodman in his test, The Process of Rate Making, which is a 1998 two volume text, they quote the great American Justice Frankfurter who stated that the process of ratemaking is necessarily resting on "fluid and changing facts" and "that the just and reasonable standard does not bind ratemaking bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free within the ambit of their statutory authority to make pragmatic adjustments which may be called for by particular circumstances."

Now, I think it is fair to note that every expert who has testified says that no cost allocation study can be perfect. And at some point in time, the judgment of the analyst becomes part of that result. And in that regard Goodman states as follows: "The primary cost allocation question in a rate case is generally not whether a more exact allocation can be constructed. Every cost allocation method is imprecise. The major question is whether the agency's judgment, the method and result are reasonable rather than whether the witness has successfully found a proxy for perfection."

And indeed this comment is cited or is referred to in two Supreme Court of the United States decisions. One was in 1949, Colorado Interstate Company and that was followed in 1983, National Association of Greeting Cards, and the full references are in my written notes. And that Court applied the following principle. And think this is important. "Allocation of costs is not a matter for the slide rule." I appreciate it was 1949. "It involves a myriad of facts. It has no claim to an exact science." And Goodman commenting on this says, "Mathematical precision is not required. The precise extent to which a service should share a particular cost is for the agency to decide and as the Supreme Court has stated, consideration of fairness, not mathematics govern the allocation of costs."

So our submission on what the law is with respect to the direction you should give yourself in determining what is the best cost allocation methodology to take out of these hearings, you should be thinking in terms of fairness first. And it's our further submission that fairness must be seen in light of all the circumstances, including the history of the previous cost allocation and rate design decisions by this Board and also the application and history of that decision over the years.

So dealing with the classification of fixed generation costs, we submit and it is our position that the Board should continue to apply the 40/60 split that it approved on April 13th 1992 and in the 1993 rate decision. And without considering anything else around it, you know, there is some pretty good reasons for continuing to do so. First, the methodology was approved after a hearing. Second, it's a methodology used in the NARUC manual. Third, at the time, it was the one that was recommended by NB Power and its outside consultants. Fourth, and this is important, and Mr. Ketchum conceded in his cross examination, if we ignore Disco's financial and corporate reorganization, that this methodology would be as appropriate today as it was in 1993.

And finally and most important, when we look at NB Power's overall generation economics now as compared to then, nothing really has changed and remains a perfectly reasonable methodology to use. So it has a lot going for it.

Now let's put this cost allocation methodology into some perspective. And when I say perspective, I want to emphasize the point that we shouldn't be thinking of a cost allocation methodology as a snapshot exercise of today. It's not as simple as looking at today's economic realities and deciding that's how the cookie crumbles. Rather, I suggest, it is reasonable for this Board in selecting its cost allocation methodology to look at what's happened over the 14 years and ask two questions. What things have things changed? And just as importantly, what things haven't changed?

So we go back to the 1992 decision. The Board concluded 40/60 division of fixed generation cost was reasonable. And after that they went and looked at the Reed Report and the Reed Report concluded if you use the Equivalent Peaker Methodology, which happened also to result in the 40/60 split, it justified the Board's April 15th 1992 decision. And the Board used this in the 1993 decision. So one of the issues is are we using 40/60, are we using Equivalent Peaker. And to be perfectly frank, we support that perhaps that's not all that important so long as the analysis is done consistently.

In the current proceeding, the EP analysis was done as of 2002. And that was before some pretty large investments were made. It's simply wrong to apply the cost splits that come out of 2002 to the actual costs incurred in 2006. And our submissions is if this Board is going to use the EP method and rely -- instead of relying on its past methodology, it should direct Disco to update its EP analysis to include all the investments made through 2006. Otherwise, we are perhaps mixing apples and oranges.

What's happened since 1992? Well, first of all, NB Power has consistently used the 40/60 split of fixed costs in its cost allocation studies.

Second, it has used these studies to set rates for the various classes for the 14 years using three percent maximum rate rule provided in the 1993-1994 legislation.

Third, we had a White Paper. We looked at what's going on in the New Brunswick electricity sector. We looked at the energy requirements. And this study made specific references to the range of reasonableness, the so-called 95 to 105 band. But, you know, it did so in the background of the methodology that this Board approved in 1992 and 1993.

Fourth, when we look at what came out of 1992-1993 rate hearings, one of the results of that was the conclusion that the residential class was being subsidized by the heavy industrial class. And we submit that over the years, the rate increases imposed on the residential class have now resulted in this class now paying its way, at least vis-a-vis the large industrial class.

According to Mr. Knecht, in his evidence, and no one has taken exception, the rate increases for the residential class since 1993 exceed 60 percent. Over the same period, the rate increases for the heavy industrial classes have increased approximately 30 percent. In real terms, residential rates have increased 14 percent. In the industrial rates for the large industrial class have actually decreased in real terms.

So using the cost allocation methodology in 1992 has resulted in a series of decisions relating to rate increases, which have impacted much more significantly on the residential class. This class was told in 1992, you are being subsidized and for 14 years, the rate decisions that have been put through by NB Power have caused them to catch up.

And indeed if we examine the results that flow from the straight application of the Board's generation cost methodology, this is the case. According to Mr. Knecht's calculations where he has taken these and applied the cost allocation method, the traditional one, he says we have got the residential class at 94.6 percent and the industrial class at 91.7.

So based on this long standing methodology the residential class has done their thing. Should they not receive the benefit of that now? The fact is they will not if either the applicants or EGNB's methodology is adopted. Both of these methodologies put the residential class in the position where they are forced to play catch-up once again. Not only has the residential class caught up but the large industrial class has fallen behind.

Now I say all this to make the obvious point, and the obvious point is if we are considering a change in the methodology, what is the sense over the last 14 years of making rate increases to cause one rate class to catch up, and where is the fairness and equity of saying, with all other things being the same, well we don't like the methodology, we are going to impose another one.

Now I don't think we should look at cost allocation methodology in isolation. And what I mean by that, there is a lot of things going on in New Brunswick electricity sector outside of the rate methodology that creates benefits for the different classes. And in particular there are a lot of benefits for the industrial class.

I want to focus if I could for a few minutes on the sale of surplus energy to the large industrial sector and the policy relating to export sales vis-a-vis the industrial class.

Now with regard to surplus energy, it's useful to remember that in 1991 there was not a surplus energy account. This didn't occur until 1997 or 1998 when surplus energy became available. In 1993 heavy industrial customers took 90 percent of their energy through firm load transmission. 2004 only 70 percent was purchased on this basis. The other 30 percent of electricity used by the industrial class is being purchased on an interruptible and surplus basis.

The interruptible and surplus power has been and continues to be a great benefit to the industrial sector. There is no element in the price that they are paying for surplus energy that makes a contribution to the fixed costs or the capital costs of generation facilities.

This means that all the other firm customers, including residential, commercial and firm transmission, they have to pick up the slack. That is, residential, commercial and firm. All the non-firm large industrials have to pay for is the incremental fuel costs plus a small add-on to cover transmission costs and a minuscule amount for OM&A costs.

And yet the revenue cost ratio is still below unity. When 30 percent of the large industrial energy needs are purchased by surplus power, the industrial sector is in fact receiving a significant benefit. If fixed costs were added to the purchase of this power, would this not work to decrease the financial requirements on the other classes?

Now the Applicant makes the argument this energy is interruptible and therefore it justifies the price break. And while that may be its contention it is important to note from the evidence there is still significant excess capacity in the system. Interruptible power is a lot less valuable to the system as a whole when there is plenty of capacity to provide that service.

Further, interruption is not a frequent event, nine events for 14 hours over the last five years. Interruptible power does have a purpose, but the NB Power system does not have a significant need for this type of energy. Certainly not to the extent that large industrial users can use it as an opportunity to purchase 30 percent of their energy on a discounted basis.

Secondly, and I suggest even more importantly as it relates between the industrial class and the residential class, is the relationship between purchase power and export sales. NB Power has the policy, and this is notwithstanding it says it is trying to develop a competitive market, and notwithstanding that Mr. Myers in one of the IRs to us says that they support the competitive market, of selling and servicing in-province load first.

This means that in-province surplus energy is sold to large industrial customers even if Disco could potentially obtain a better price for this energy in the export market.

Now I'm not opposed to selling some surplus energy to New Brunswick industrial customers, even those who are not willing to pay the full cost for plant capacity, but we ought to do it in a way that doesn't take too much money away from those customers who are willing to and have been paying for the capacity over the years. And if we were going to have a competitive market, should we not sell to interruptible customers at the market price?

Now if you sell at the market price, competing with New England, one of the things that happens is there is a significant credit to residential customers. When NB Power sells to large industrials at surplus energy rates, it loses potential profits it could make up from export sales. The residential sector, the firm industrial customers and especially general service customers, end up paying for all that capacity that allows these export sales and lose the potential profits.

They are simply losing the benefit of this when the decision is made to make the sale of surplus energy to industrial customers before we make the sale to export markets.

As can be seen, there are a number of ways that the large industry receives significant benefits. These benefits are rate design and policy issues. You know, they have to be taken into consideration when we start deciding which is the best cost allocation methodology to use.

The Board has a choice between continuing with its existing methodology, which is accepted and is reasonable, or choosing the Applicant's option which is unfavourable to the residential class, or choosing EGNB's which is even more so.

And it is submitted in so deciding this Board should give fair recognition to the fact that by its rate design and policies, NB Power has created several significant advantages outside of the cost allocation methodology for the large industrial class. And even more important perhaps is to take into consideration that these advantages are at the expense of the residential class.

So having discussed what has happened since 1993 perhaps before I move on to discussing the Applicant's and EGNB's cost allocation methodologies, it is important to identify what has not changed since 1993.

The most important factor is there has not been a significant change in the configuration of NB Power's generation assets. What this implies is that in the absence of such changes the methodology that worked in 1992 and was approved by this Board should continue to application in 2006.

Now the one change I have not discussed is the corporate and financial reorganization of NB Power. In NB Power's cost allocation, NB Power feels this makes a difference. We submit it's important to note there has not been, at least from a generation perspective, a structural change. Because of this we submit that the existing methodology in the 40/60 split of fixed generation costs remain appropriate.

And happily for us, Mr. Ketchum in his cross examination agrees that but for the PPAs resulting from the corporate and financial reorganization, the 40/60 split would still be acceptable today.

I want to move on and deal specifically with the positions of the Applicant and EGNB as it relates to classification of fixed costs.

The Applicant's position, as I have indicated, is that the classification and allocation of costs is a function of the billing determinants contained in the purchase power agreements. Well the Applicant says this is so so long as it makes sense, at least to them.

So when we come to the Genco agreement, which bills out most of the fixed costs as a demand charge, Disco decides it will use the PPAs to classify Genco's fixed generation costs. But they didn't do it all the time. They reclassify the costs where they didn't like the answer.

And in particular I'm dealing with the reclassification of the $73 million which is the fixed O&M or the contribution to fixed costs, the $7 per megawatt energy charge.

That's how they describe it, $7 per megawatt hour. And it results in $73 million. And then they reclassify that.

So they use the PPAs and then they don't use the PPA and they end up with what was a 40/60 split in 1993 and now it's 87/13.

I know I'm rehashing Mr. MacDougall's fine arguments but I do want to get them on the record.

And if that's not enough, let's go to the Nuclearco PPA.

The billing determinant is 100 percent energy and zero percent demand. Well NB Power says this is clearly so illogical and unreasonable, so as a proxy we will use the 40/60 split.

During my cross examination as to what the underlying basis for deciding when to use the PPAs and when to ignore them, I tried to strike -- attack the Applicant's position that their decision as how they came to strike that proper balance. I invite you to re-read that part of the transcript. I really, really did feel that there was really not a very good answer to that. I don't know how you strike the balance. What underlies it?

Now talking about striking the proper balance, I put this question and asked. Wasn't that what the Board did in 1992 with its 40/60 split? Why shouldn't the 40/60 split that applied to fixed costs before restructuring not apply to those same fixed costs after restructuring?

I take some comfort that the experts, and I think all of the experts who have commented on the use of PPAs to classify the fixed generation costs, seem to share the same concerns we have. Dr. Rosenberg's eight points confirm, and I think the phrase he used in his evidence was that the PPAs simply ignore economic cost causation. Similarly Mr. Knecht rejects the PPAs as a method of classification for fixed generation costs. The PPAs reflect the desires and the interests of the parties that negotiated those agreements. Disco witnesses admitted -- or at least they could not rebut the argument that no cost allocation expertise was considered in setting the billing requirements of the PPAs.

Those determinants may reflect risk sharing, they may reflect certain policies, they may be used to create incentives for the different companies, they may be a way to write a contract. Those PPAs do not reflect cost causation.

In addition, if we do cost causation based on PPA billing determinants, NB Power can adjust those billing determinants any time they want. You know, and let's be honest about it, right now when we write those PPA contracts and amend them, we still have the same old NB Power making the rules. You know, at the risk perhaps of overstating, it is submitted that to defer cost allocation to the PPAs is tantamount to this Board abdicating its jurisdiction to approve cost allocation methodology to the Applicant.

Now I would like to move on to EGNB's methodology, a methodology which is a more sophisticated conceptual model than that which the Board approved in 1992.

Dr. Rosenberg and my colleague Mr. MacDougall have explained well, certainly I didn't do a good job of trying to get it explained in cross, but the reflection of the dual symmetry, not only of the capital for fuel trade-off but also the fuel for capital trade-off, which is the full intention of the Equivalent Peaker method.

And in Dr. Rosenberg's approach to this you classify the fixed generation costs plant by plant into demand and duration costs using the EP method. You allocate the demand costs on a peak basis. Then you take the duration costs and allocate them on an energy basis over only some hours of the year. And to figure out what some hours means you need to do a breakeven point plant by plant, and then you allocate the fuel costs on those hours.

And then you use those results for who is paying for the fixed cost to assign the generation from one plant to each rate class. So in theory you get more assigned -- assign more of the low cost peaking plants, you have to pay more of the high fuel costs associated with that plant. I'm not sure if the theory always works out.

Conceptually Dr. Rosenberg's conceptual model is not new to this Board. It's useful to turn back to the 1992 hearings. And no doubt you might expect I was somewhat concerned to have learned from my expert that he had advocated a cost allocation study in 1992, that if not in its details, but in its concept was the same as Dr. Rosenberg. And in 1992, Ms. Chown and Mr. Knecht advocated on the part of the large industrial users that the "dual symmetry" and the "fuel for capital trade-off" be considered.

What is important the Board in 1992 rejected the use of this particular methodology. And what is even more important, little has changed since then. The obvious conclusion is the Board's reasoning for not adopting the modified Equivalent Peaker and the dual symmetry in 1992 remains as appropriate today as it did then.

We also submit that it is important that EGNB's sophisticated modification of the Equivalent Peaker is presented on the basis that it reflects, in Dr. Rosenberg's words, today's economic reality. It does not, we would argue, take into account the 14 years of intervening history. It does not take into account the policy and rate factors which have benefited the large industrial sector. Rather his methodology is a snapshot.

And we submit that fairness and reasonableness do not exist in a vacuum. They exist within the context of all that goes around about it. And while some witnesses, such as my own, might argue that Dr. Rosenberg's theory -- or methodology has appeal and theory, it has some practicalities which have not been addressed.

And this brings me to Coleson Cove. First if we use Dr. Rosenberg's methodology, the demand/duration cost split of Coleson Cove is 95 percent demand/5 percent duration costs. The higher allocation of capital fixed costs demand, i.e., the 95 percent has its greatest impact on those customers such as residential customers who have a low capacity factor. And thus the residential class takes it on the chin, once.

Secondly, according to Dr. Rosenberg's methodology, the five percent which is energy (or, which Dr. Rosenberg calls "duration related"), results in energy costs being allocated to the customers based on 8 percent of the year. Coleson Cove duration costs are assigned on a January energy basis, because the breakeven capacity factor between a combustion turbine -- I mean writing this out was tough -- and oil/gas-fired new combined cycle plant is 8 percent. Dr. Rosenberg says 8 percent means January, which is the time of the year when the residential customers would have their most significant contribution to peak load. Thus, the residential class takes it on the chin twice.

And finally, when Dr. Rosenberg figures who should pay for the fuel costs from Coleson Cove, he relies on how the capital costs were allocated. Thus, the allocation of both the demand and the duration costs in the month of January are used to determine who gets to pay for the energy costs. And, of course, the energy costs for

Coleson Cove were a littler higher than we anticipated when we decided to do the upgrade. And thus, for the third time, the residential class takes it on the chin.

As can be seen, and as Mr. Knecht has stated in his evidence, the Rosenberg approach, as it applies to Coleson Cove, causes the residential customers to take it on the chin three times.

Had Coleson Cove worked out at the $29 per megawatt hour as suggested in 2002, it might not have been a bad deal. However, when you have the same result at $72 per megawatt hour, I ask is it fair and is it reasonable to have one class absorb a disproportionate share of these costs of the Coleson Cove refurbishment?

Dr. Rosenberg would say yes. He would say this is an economic reality and in order to get the proper price signals then a hard mathematical application should be made. I leave that with the Board.

When I discuss the applicable law in deciding cost allocation methodology, what is important is not necessarily the mathematical precision but an assessment of what is fair and reasonable. And in this context, even if we accept Dr. Rosenberg's sophisticated model by itself as reasonable, this question remains to be asked. Should we adopt a methodology which results in Coleson Cove refurbishment being disproportionately allocated not once, not twice, but three times to the residential and other low load factor classes.

The last point that I want to make with regard to the proper methodology for classification and allocation of fixed generation costs is what's going to happen in the future. In this regard, Point Lepreau is on the horizon and unfortunately this is something under Dr. Rosenberg's methodology which I would expect to be of some benefit to the residential ratepayers.

If you are going to use his methodology after Point Lepreau, the residential payers would come out ahead. At least they would versus the large industrial classes if not in absolute terms as I understand the potential cost of the refurbishment. At the present time if I look at Disco EGNB IR-36, Point Lepreau results in a 30/70 demand split. After the investment of money and given the price of oil the breakeven point according to Dr. Rosenberg would decrease. And it if decreases, the energy (or duration-related) costs would grow to approximately 80 percent of the fixed costs. More of these costs, of course, would be assigned to high load factor customers, because the energy share would be larger.

This economic reality does not exist today and cannot be part of Dr. Rosenberg's snapshot methodology. We would submit that the Board's approved methodology seems to have element of flexibility in it that allows for some forward thinking that EGNB's methodology does not.

In closing on this issue, we submit that the Board-approved methodology has a history and was accepted over a conceptual model similar to EGNB's proposed methodology. Nothing has changed that should force the Board to reconsider this decision.

And finally the accepted methodology has been a methodology used in the context of several rate design and policy issues which directly and indirectly affect the impact of electricity pricing on the residential and large -- and large industrial rate class.

Now very briefly I want to touch on the role of marginal cost pricing. And in that regard, we heard I think an inordinate amount of cross examination on the role of marginal cost pricing in the future. The evidence almost came to the point where it would seem to me that somebody must have been suggesting that we adopt marginal cost pricing today.

I did not see that in the evidence. And I specifically asked Mr. Garwood and Dr. Adelberg, whether this was, in fact, the case, and they both agreed no one has put forward a marginal cost study at this time. And certainly that was not my witness', Mr. Knecht's recommendation.

However, we would say this, in view of the intentions of the government White Paper to create a competitive market, where pricing would be based on real competition, we have suggested it might be useful to look at the future and determine whether or not marginal costing could be used as a proxy for competitive market pricing. That's all we have suggested.

Whether or not this study should be completed now or in the future, I leave to the discretion of this Board, but I would say that if a competitive electricity market does start to develop at some point in time, cost allocation methodology will have to be reviewed. The change to market pricing may create significant changes to electricity pricing.

And if we are going to base prices on competitive factors, there seems to be at least one train of thought that marginal cost pricing is closer to real market pricing than can be found in an embedded methodology. This being so, we recommend that marginal cost allocation and pricing should be looked at at some point in time.

That's all I want to say about it. Our view is that until such time as we know how the new competition develops, better the devil you know than the devil you don't. And therefore the Board's 1992 methodology in the 40/60 split for generation costs would be best served as the accepted methodology at this hearing.

I want to very briefly -- and I assure the Board that it is brief. I will speak to the issue of transmission costs. We are in agreement with the Applicant and in disagreement with the EA advisors. The EA advisors would use a one CP methodology for the classification and allocation of transmission costs. We are of the view that this Board has reviewed the issue in great deal at the OATT hearings and has used other methodology for setting of the tariffs.

These tariffs are not inconsistent with the requirements of FERC, although they may not exactly comply with their preferences. They are not so inconsistent so as to create problems for the NBSO or Transco in its international dealings. If the cost methodology is to be changed, then we would suggest the only proper way to have it changed would be at an OATT hearing. Our position is that the Applicant's methodology is supportable on the basis that it reflects the current tariffs which are enforced by this Board.

Very briefly with distribution costs, we have a couple of comments. And perhaps I will preface this by saying there doesn't seem to be any area of cost allocation where judgment seems to be more important than it does with the distribution costs. And I would probably agree that all the different suggestions have that element of reasonableness attached to them.

However, having said that, it seems that some of the choices that the Applicant has made seem to favour the industrial class. We note that in particular some significant changes which favour non-residential customers to whom distribution services are provided.

We further note that of the three common methodologies that are used for the classification of plant distribution costs of poles, transformers and conductors, there is the minimum system, the zero intercept and the basic customer. The minimum system is the worst for the residential customers. The basic customer, or 100 percent demand is best. And as Mr. Knecht's evidence shows, many utilities recognize the minimum system necessarily overstates the customer component.

A couple of ways to adjust this, either use the zero intercept approach or classify a portion of the primary distribution system as demand-related.

We advocate the zero intercept model. It seems to be the appropriate middle of the road. My little graph is designed to get us in the middle of the road. Everyone has stated with regard to distribution costs and the general absence of good data in this area, the use of good judgment seems to predominate.

Our submission is that this Board should use the zero intercept methodology with regard to distribution plant costs. And, if there is an absence of data to apply the zero intercept method, I suggest that Disco look at the practices of some of its neighbouring jurisdictions with regard to classifying distribution costs.

I want to talk about a couple of issues with regard to rate design. There seems to be a common agreement that declining block rate in the residential class should be removed. The difference seems to focus on the question of pace and the method of implementing this change. In any event, the pace should be a lot faster than has happened since the last rate case.

There is no doubt, and the Applicant has confirmed, that in terms of risks to revenue, the blending of the first and second blocks does create risk for it.

We note with some concern, the extent to which the residential rate class has been skewed by the presence of farms and churches. It is our view that farms and churches should be removed and separated into a separate class. These are customers which probably deserve some protection and if they deserve protection the Board can create caps for them in the short term with the Applicant being permitted to study the issue and come back with a reasonable approach. It may well be that these rates should be capped at 95 percent of the current residential rates.

Beyond this point, I do not have a specific recommendation on how to deal with farms and churches, but I do suggest that if we are going to remove the declining block rate, these elements, which to use Mr. Larlee's words are not "domestic residential customers" should not impede the move towards eliminating the declining block rate.

Mr. Knecht, in his evidence, has made a suggestion which we endorse for consideration of the Board. He proposes to aggressively attack the secondary block rate and would propose to have it removed within a three or four year period. We would recommend this to the Board and ask the Board to order Disco to take the necessary steps to implement this.

We also ask the Board, on Mr. Knecht's recommendation, that the Board establish specific guidelines for the maximum increase faced by the large truly domestic residential electric heat customers, such as 1.5 or twice the residential average rate increase over the course of implementing the declining block rate.

Without some specific guidelines, I fear we will continue to face what we have seen in the past. And I am not stealing your thunder, Mr. MacDougall, progress at a glacial pace. EGNB has advocated seasonal rates. We are more reserved with respect to seasonal rates than EGNB in the absence of accurate and timely residential rate class load research.

We do however concur with EGNB that seasonal rates do send important price signals. These price signals are the same ones that are being sent by removing the residential declining block rate. It is our recommendation that the declining block rate be removed, accurate load research be obtained and Disco complete a study on the impact of seasonal rate differentials and file the same with this Board.

With respect to general service II Class, we recommend that this class be eliminated from the Applicant's rate structure. Although, we have heard evidence that Disco no longer offers the GS II rate to new customers it has continued to make the service available to those it has grandfathered. The recommendation to eliminate the GS II class is consistent with the recommendation of this Board in 1992 and there has been very little progress made with regard to removing it. We suggest that the Board order the class should be discontinued over the next three years and that one rate for general service exist.

We believe there should be a separate for surplus and interruptible sales. Interruptible sales are very different from firm sales. Rates and allocated generation costs are not based on embedded costs -- they are based on incremental costs. If interruptible customers essentially pay only the incremental fuel costs needed to serve them, they are making no contribution to recovering costs, and, therefore, losing that load would not have a direct negative effect on other Disco customers. Moreover, the load pattern for interruptible is very different than that of firm large industrial load. It has a much lower load factor and it is only used on a opportunistic basis. For that reason, we submit it makes more sense to separate this load into a separate class and begin to consider whether these customers should be required to make some contribution above incremental costs, especially if they are eligible for below-market prices.

We further would comment on this regard taking up Mr. MacDougall's comments on standby charges, that this might be a good time to fit standby charges within this class as well.

We further submit that the amount of surplus and industrial sales that is priced below market should be limited only to a portion of the firm transmission load which is purchased. For example, we would submit that an industrial customer be entitled to purchase an amount up to 15 percent of its firm transmission load as surplus energy rates which are set by the Board. Thereafter, any additional energy which is to be purchased must be purchased in competition with the export market.

We believe this represents a fair and reasonable approach so as to continue some benefit to industrial customers but at the same time allow classes which benefit from the export sales to receive at least some of the impact of that benefit.

The last issue we want to discuss very briefly is the need to acquire information and that NB Power should be forced to provide this information to the Board.

All the experts who have testified at this hearing have pointed out the lack of load research on class by class basis. We believe that load research is imperative, especially if we are going to have currency with present methodologies on cost allocation and potentially move forward into a marginal cost pricing system in the future. This is imperative if we are going to sustain the credibility of the current cost allocation information.

So where does that leave us? Well it leaves us as follows, and I will read into the record and I do have copies I will distribute and I will also be distributing hopefully by the end of the week, the formal text of my remarks. But this is the order that we are requesting.

We request the following order:

1. The Applicant file a revised cost allocation study with the following parameters:

1. Fixed generation costs are to be classified on a 40 percent demand 60 percent energy basis consistent with the previous decisions of the Board.

2. Energy costs be allocated on the basis of energy consumption.

3. Transmission costs to be classified and allocated on the basis of the OATT approved by the Board.

4. Distribution plant costs. Examples, poles, conductors, transformers, to be classified on the basis of the zero intercept method.

5. Export sales credits be credited to demand in a

manner consistent with the Board's CARD decision of 1992.

Second order we are requesting. That the Applicant remove farms and churches from the residential customer class and that information verifying this removal be filed with the Board.

Three. That the Applicant file a plan with the Board that details the process to be taken to remove the declining block rate structure for the residential class within four years from the date of the order, or at such other date as specified by the Board. The Applicant should also include specifics on how the residential class will be informed of the changes to the rate design.

Four. That the Applicant file a plan with this Board that details the process to be taken to eliminate the general service II class within two years from the date of the order or such other date as set by the Board. The Applicant should also include specifics on how the general service II class will be informed of these changes.

Five. That the Applicant file with the Board a new class for interruptible and surplus sales, with details on limitations on the quantities of surplus and industrial sales that can be purchased.

Six. That the Applicant file with the Board a plan to conduct customer class load research and load profiling.

This plan should specify the following: i. The customer classes to be covered in the load research, together with an explanation for those classes not covered. ii. The number of meters to be used for each stratum for each class, together with a defence of these numbers. iii. The duration (or interval) time for the survey, together with a defence of this duration. iv. The Applicant's plans for ongoing research over the next several years.

Seven. That the revised cost allocation study, the plans for the residential and general service II rate designs and the plans for load research and load profiling program are to be filed with the Board before the start of the revenue requirement phase of these hearings, and that it form part of the proceedings.

Mr. Chairman, I was a little longer than the 31 minutes. But I did try to move along. I do thank the Board for its attention. I thank it for the opportunity to have addressed it with regard to these issues.

CHAIRMAN: Thank you, Mr. Hyslop. You wouldn't consider throwing a few facts on the paper and save the Board a lot of work -- you are not getting it. In other words, that is quite a decision piece you just read. I thought if we had a few facts up front it would save us some work.

We are going to take about a four minute recess and be right back in. Thank you, sir.

(Recess)

CHAIRMAN: We are missing one Commissioner but of course we are not hearing any evidence and he has approved these questions as well. Tomorrow, and Mr. Goss is just having them printed up, we took a couple out. But these are the questions we would like counsel to address in their summation if they feel so inclined.

And it is really the subject matter of these questions we want you to do. First, do parties believe that the interruptible rate should include a contribution to fixed costs and if yes, how much of a contribution?

Do parties consider the interruptible rate option should be made available to other rate classes and, if so, which classes?

Do parties believe it would be appropriate for Disco to develop a curtailable power (demand response) option whereby customers would be paid to curtail or eliminate their load at times of peak demand?

And last, do parties believe that there are benefits to the system from the presence of a low load factor customer in the areas of generation maintenance, reserve requirements and generation availability for export sales, and if so, are such benefits properly calculated by the cost of service studies?

Those are the additional matters we would like you to address tomorrow morning. And the Panel wants to thank counsel for really being very succinct and to the point and we are pleased that we got through it in one day and we look forward to tomorrow.

So we will see you at 9:30 in the morning.

MR. HYSLOP: I am sorry, my written comments -- my written comments aren't quite prepared yet. I was going to ask the Board if I might have until Monday to file them with the Board and with the parties?

CHAIRMAN: Well we had planned on working all weekend, Mr. Hyslop. I think that would be sufficient, Mr. Hyslop.

MR. HYSLOP: Thank you very much, Mr. Chair.

CHAIRMAN: Okay, great. See you in the morning.

(Adjourned)

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

Reporter