New Brunswick Energy and Utilities Board

IN THE MATTER OF an application by New Brunswick Power Distribution and Customer Service Corporation (DISCO) for approval of changes in its Charges, Rates and Tolls (Includes Interim Rate Proposal)

Delta Hotel, Saint John, N.B., on December 20th 2007.

Henneberry Reporting Service

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Delta Hotel, Saint John, N.B., on December 20th 2007.

BEFORE: Raymond Gorman, Esq., Q.C. - Chairman
Cyril Johnston, Esq. - Vice Chairman
Mr. Roger McKenzie - Member
Mr. Don Barnett - Member
Ms. Connie Morrison - Member
Mr. Yvon Normandeau - Member

N.B. Energy and Utilities
Board Counsel - Ms. Ellen Desmond

Board Staff - Mr. Doug Goss
- Mr. John Lawton
- Mr. David Keenan
- Mr. Dave Young
- Mr. Andrew Logan

Secretary to the Board - Ms. Lorraine Légère
Assistant Secretary - Ms. Juliette Savoie

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CHAIRMAN: Good morning, everyone. I will take the appearances at this time starting with the Applicant.

MR. MORRISON: Good morning, Mr. Chairman and Members of the Board. Terry Morrison and Ed Keyes for the Applicant. At counsel is Mike Gorman and Darren Murphy.

CHAIRMAN: Thank you, Mr. Morrison. CME?

MR. LAWSON: Good morning, Mr. Chair, Members of the Board. Gary Lawson for CME.

CHAIRMAN: Thank you, Mr. Lawson. Conservation Council of New Brunswick?

MR. KIDD: Good morning, Mr. Chair, Members of the Board. Scott Kidd for the Conservation Council.

CHAIRMAN: Thank you. Enbridge Gas New Brunswick?

MR. MACDOUGALL: Good morning, Mr. Chair, Board Members. David MacDougall for Enbridge Gas New Brunswick.

CHAIRMAN: Thank you, Mr. MacDougall. Irving Oil Limited? JD Irving Pulp & Paper Group?

MR. WOLFE: Good morning, Mr. Chair. Wayne Wolfe.

CHAIRMAN: Good morning, Mr. Wolfe. NB Forest Products Association? Dr. Sollows?

DR. SOLLOWS: Good morning, Mr. Chair and Panellists.

CHAIRMAN: Utilities Municipal?

MR. ZED: Mr. Chair, Members of the Board. Peter Zed and I am joined this morning by Dana Young, Eric Marr, Michael Couturier and Daryl Shonoman.

CHAIRMAN: Thank you, Mr. Zed. Vibrant Communities Saint John?

MR. PEACOCK: Good morning, Mr. Chair. Kurt Peacock here.

CHAIRMAN: Public Intervenor?

MR. THERIAULT: Good morning, Mr. Chair. Daniel Theriault and I am joined this morning by Robert O'Rourke and Jayme O'Donnell.

CHAIRMAN: New Brunswick Energy and Utilities Board?

MS. DESMOND: Ellen Desmond, Mr. Chair. And from Board staff, Doug Goss, John Lawton, Dave Young, Dave Keenan and Board Consultant, Andrew Logan.

CHAIRMAN: Thank you, Ms. Desmond. This morning when we went into our room we found a Christmas card. So I don't know if somebody wants that marked as an exhibit. It seemed to be signed by everybody. I did want to say though that the portion of that -- I'm sure you passed the hat -- that was paid for by DISCO, the chances of us allowing that in the revenue requirement are pretty slim.

MR. MORRISON: Put it in a deferral account.

CHAIRMAN: So I think, Mr. Zed, you are up.

MR. ZED: Well it really threw me for a bit of a loop. I have to depart from my prepared text at the outset. I had good afternoon in anticipation of being on yesterday but good morning, Mr. Chairman, Commissioners.

As you know, I represent the New Brunswick Municipal Electric Utilities, namely Energie Edmundston, Perth Andover Electric Light Commission and Saint John Energy.

I have been in attendance with several representatives of these organizations throughout the entire hearing and like to begin our presentation by thanking the Board, thanking the Chairman, for the opportunity to participate in the process as an intervenor and to present our position.

Your patience and attention to the witnesses has been much appreciated.

Although we had to qualify as an intervenor at the outset, I think it may be helpful for me to just remind everybody why we are here.

We became formal intervenors in this proceeding for the purpose of addressing the implications of this application to the customers of Utilities Municipal, the ratepayers and the tax payers of our communities.

Saint John Energy itself serves about 36,000 residential, commercial and industrial customers in the city of Saint John and we purchase 100 percent electricity requirements at NB Power's wholesale rate.

The city of Edmundston, with a population of about 17,300, including St. Basil, St. Jacques and Verret, and its municipal electric utility, Energie Edmundston, now serves about 5,800 customers, which represents about 65 percent of Edmundston's total population.

Perth Andover Electric Light Commission distributes power to about 1,100 customers in the Village of Perth Andover.

Together Energie Edmundston and Saint John Energy comprise the wholesale customer class of DISCO which represents, according to DISCO's cost allocation study, 9.3 percent of system peak demand and 8.3 percent of requirements for generated energy.

These municipal utilities and the customers they serve are thus directly and immediately impacted by the decisions this Board will make as a result of this application.

The Perth Andover Electric Light Commission is presently served under a contract with a third party supplier other than DISCO so that effects of DISCO's rates on its customers are at present indirect. However, it is clear that the service and pricing environment of the entire province is dominated by DISCO so that the outcome of this proceeding is still of major importance to Perth Andover Electric Light Commission as an industry participant. And of course to its customers as consumers of electricity in New Brunswick.

Now 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 -- and if I may paraphrase -- says that this Board will approve rates which are just and reasonable.

The Municipal Utilities fully support that ideal and have selected certain key issues on which to offer our views to the Board. We have divided our issues into two groups. Those issues that directly impact the test year and those issues which do not directly impact the test year but which in our view are important to future decisions in the regulation of DISCO.

The first group, issues directly impacting the test year, include use of the approved cost allocation methodology, the results of the forecast of load growth for the wholesale class, division of the proceeds of the PDVSA settlement between the Province and electricity ratepayers, the interest coverage ratio, attribution of incremental generation cost to export and interruptible sales. And finally in this group, appropriate levels of relative rate increases among the firm classes of customers.

The second group, which are issues beyond the test year include a single specific issue of cost allocation methodology, which is treatment of CT and emergency generation costs, regulatory oversight of affiliate transactions, a recommendation for filing of actual historical results and forecasts for years other than the test year in future proceedings, and finally in this group, our position on the need for and timing of a future CARD hearing.

Now I intend to leave a copy of my remarks with the Board at the conclusion and I believe it is fully indexed and footnoted, so that may save some time.

First I will start off with issues specific to the test year and start off with dealing with the issue of cost allocation methodology.

In support of its proposals on relative customer class rate increases and rate design, DISCO has submitted a class cost allocation study. In describing the methodology, DISCO says, "The evidence uses accepted cost allocation methods and a rate design that is guided by the Board of Commissioners of Public Utilities, December 21st 2005, Cost Allocation and Rate Design ruling. DISCO's CCAS methodology is unchanged from that approved in the December 21st 2005 CARD ruling."

Two years ago the Public Utilities Board conducted an extensive and thorough CARD review proceeding, at which evidence was presented by several parties on aspects of the methodology. The Public Utilities Board ordered certain changes to the methodology initially proposed by DISCO in that proceeding, but with respect to generation costs, which were the most contentious issue at that time, the PUB concluded as follows, and I'm quoting, "The Board therefore believes that it is appropriate to continue to use the method that was approved by it in the April 15th 1992 decision with respect to the classification of generation costs as either demand or energy related."

In the current proceeding this Board has said that the overall requirement is allocated to the various customer classes based on a cost allocation methodology that was approved in a decision of June 19th 2006. There was some discussion on the methodology at the hearing on September 27th 2007, but no party suggested that a review of the methodology be done prior to the Board setting rates for the 2007/2008 year. The Board intends to accept the currently approved method for use in allocating costs for 2007/2008.

Now notwithstanding this, some parties have put forward alternative approaches to cost allocation in this proceeding. Mr. Knecht, in his prefiled evidence and oral testimony, urged that it is more appropriate to examine methodology of classification of distribution costs outside of the context of a generic CARD hearing.

Mr. Drazen presented an alternative approach to the allocation of generation costs, which constitutes the largest component of DISCO's total revenue requirement. Changes in the allocation of generation costs therefore have the largest potential impact on the revenue/cost ratios of the customer classes of any aspect of the cost allocation methodology.

We urge the Board to consider not only that it has already ruled that it will accept the currently approved methodology for this test year, but also that Mr. Drazen has not put forward a complete analysis of any alternative.

As Mr. Knecht testified, and I quote, "Unfortunately, because DISCO has not provided any information regarding costs, I think Mr. Drazen can only make rough estimates of the impact of his proposed changes to the CCAS, and as I mentioned, he only evaluates that impact for large industrial customers. Both conceptually and in many ways quite practically both of the points that Mr Drazen raise and the analysis that he conducts were raised in the 2005-002 proceeding by Dr. Rosenberg on behalf of EGNB.

And Dr. Rosenberg had significantly more cost information than was available to Mr. Drazen in this proceeding. In that proceeding the Board did not accept Dr. Rosenberg's proposal and in this proceeding, I think because he doesn't really have a basis to do so, Mr. Drazen has not developed any reasons why the economic rationale in the earlier hearing is no longer appropriate.

Now furthermore, we don't take Mr. Drazen to be recommending that an alternative methodology be adopted at this time. The conclusion of his prefiled evidence is rather for a new CARD hearing at some point in the future. And I quote, "We suggest that the Board carry out a full review of the cost allocation methods. This would cover not only this issue but all other bases for allocating costs among the classes."

In response to interrogatories he further clarified, quote, "The recommendation is not that the Board adopt the break even methodology in this proceeding, but that the Board consider the impact of such a methodology in evaluating DISCO's proposed revenue allocation among classes."

The purpose of his analysis is therefore not specifically to recommend a cost allocation methodology, but merely to raise uncertainty about the appropriateness of the relative rate increases to classes being proposed by DISCO.

It is our position that the methodology of classification and allocation of generation costs were extensively reviewed in 2005 and that there have been no significant changes to either the structure of the industry or the underlying pattern of generation cost incurrence since that time. The approved cost allocation methodology should, in our view, be the basis on which the appropriate class rate increases for the test year are considered.

Now I will move on to the issue of forecasting. DISCO has forecasted the load growth of the residential, General Service and industrial distribution classes for the test year as 6.4, -3.9 and 5.7 percent respectively, while growth to the wholesale class is forecast as 7.1 percent. By way of explanation, DISCO says, and I quote, "The wholesale class includes power sales to two municipal utilities. This class is comprised of residential, general service and 32 industrial distribution customers located within these service territories. The 84 gigawatt hours or 7.1 percent growth in wholesale sales reflects warmer than normal" -- and then they have in brackets plus 33 gigawatts in 2006/07 -- "and economic activity in the sector, which is partially offset by the impact of natural gas and price elasticity."

Now comparison of the growth rates shown in this forecast raise the question of why the wholesale class, which is composed totally of residential, general service and industrial distribution customers, should apparently be forecast to grow at a rate which far exceeds the weighted average of these same classes in DISCO's service territory, and far exceeds the highest growth rate forecast for any of these classes individually.

It has been our understanding that DISCO makes a forecast for each of the end use classes on a province wide basis, and then apportions between its own customers in those classes and those of the municipal utilities.

We therefore probed with two IRs and subsequently in cross examination to determine whether DISCO had gathered any specific data or applied any different variables in its forecast models that would explain the difference.

The first of these two IRs requested DISCO to, quote, "Please explain more clearly the make-up of the 7.1 percent forecasted energy sales growth for wholesale."

But in response to the question DISCO did not explain how the forecast of this growth related, or was adjusted, from the provincial forecasts.

Our understanding of the response to a subsequent interrogatory is in fact that the growth level of each end use class within wholesale is forecast to be the same as the growth of that class within DISCO's service territory, but the base level of consumption is the output of DISCO's long-term econometric model and not the actual level.

And I quote, "Each distribution class, residential, General Service and industrial, is forecasted in aggregate at a provincial level and apportioned between DISCO and wholesale municipal utilities based on historic trends. As a result, no distribution class within the wholesale service territories are forecasted to grow at a faster rate than similar customers in other parts of New Brunswick. The higher year-over-year growth of wholesale shown in table 9B is the result of actual wholesale sales being lower in 2006/7 than forecasted by DISCO's long-term econometric models. These lower actual sales may result from different weather and economic conditions in the wholesale service territories than DISCO's. Key load forecast model variables are at an aggregate provincial level and as such a table comparing wholesale and DISCO service territories is not available."

Now DISCO suggested that weather or economic conditions in the wholesale service territories may be responsible, but there is no indication that they had done any analysis to verify these assumptions.

The Municipal Utilities are very concerned that some aspect of DISCO's approach to forecasting results in such significant apparent inconsistencies which have not been adequately explained.

We therefore urge the Board to order that DISCO, when bringing forward revisions to its long-term forecast methodology as ordered in January of this year, clearly explain the interactions between the long-term forecast models and the short-term forecast in its proposed methodology, and set out for the Board's approval an approach to short-term forecasting that either results in the same growth factors for DISCO and wholesale or substantiates the differences in forecasting percentage growth rates.

Next I will move on to the issue of the PDVSA settlement. In her oral testimony Ms. MacFarlane explained the rationale for exclusion of $47 million from the amounts of the settlement proposed by DISCO to accrue to the benefit of NEw Brunswick electricity customers. The basis for this was that the amount formed part of the deficit of NB Power, which was absorbed by the province on restructuring. And there was an exchange -- questions in the transcript.

So the $47 million is only part of the actual costs incurred by NB Power, I will call it, in preparation for the use of Orimulsion, correct? Ms. MacFarlane: That's correct. Question: And this is the part that was in fact -- why it was chosen we won't get into, but this part was in fact absorbed, the debt was written off by the Province. Is that effectively a correct summary? Ms.

MacFarlane: It would be wonderful if you could write off debt, but the debt stuck around. Question: Okay. Ms. MacFarlane: The asset was written off by NB Power and that loss would have been accumulated in NB Power's deficit. The deficit was absorbed by the Province. Question: Okay. Now this happened, as you say, in the year having -- the rates having been based prior to that year having occurred? Ms. MacFarlane: That's correct. And it's for this reason that it wasn't factored into the rate setting. Is that right? Ms. MacFarlane: That's correct.

That being perhaps the clearest explanation of why the $47 million ended up where it was, the Municipal Utilities have a strong concern about the appropriateness of excluding full amount of the $47 million. The approach taken by DISCO provides for recovery of 100 cents on the dollar by the Province for the amounts of the Orimulsion-related deficit which it absorbed. However, it has not been adequately demonstrated that ratepayers have similarly recovered 100 cents on the dollar, even if only actual expenditures, and not lost opportunities for reduced fuel costs, are taken into account.

The DISCO witnesses testified that approximately $700 million in capital expenditures were made, of which some component provides value to DISCO's customers even without Orimulsion. However, no specific evidence was provided as to how much the Orimulsion-specific component might be. DISCO was asked for an undertaking to provide information to answer this question. And I will quote from the testimony.

"It strikes me that the question arose out of what I understand the evidence to be as well was that the 287 million was intended to cover all of the incremental costs of fuel that were there because only of Orimulsion, and not of the general refurbishment that would have taken place anyway. And I think the question was could you break that out? And I thought your answer, quite frankly, earlier was that yes, you probably could? Ms. MacFarlane: And the only clarification, Mr. Chair, I made to that was that, as I think it through, to what account shall you say -- shall I say would we attribute the cost of the scrubber? Given that we have ended up with the scrubber and all the benefits that come from the scrubber, one could not necessarily say it was incurred solely for Orimulsion. So from that perspective the line by line may be difficult, but I certainly will - we will provide whatever we can that would aid in your consideration of this question."

Now we accept the evidence of DISCO that the Province has absorbed a loss of $47 million, and it is fair that the Province should recover something. However, we would consider it inequitable when two parties are sharing the proceeds of the settlement, the Province and the ratepayers, that one party should be entirely made whole while the other is not.

We therefore propose that the Board use the information provided by DISCO to support the allocation of the proceeds. As an example, if it is satisfied that the total cost attributable to Orimulsion are $470 million and the Province has absorbed $47 million, or ten percent of the total, then the province should receive ten percent of the total settlement, or $33 million, and the remaining 90 percent should flow to the benefit of ratepayers. In any case, the maximum amount flowing to the Province should of course be the $47 million proposed by DISCO.

Now in suggesting this approach, we are very concerned by the difficulty that the DISCO witnesses expressed in accurately attributing costs between Orimulsion and other benefits, and believe that possible negative impact on ratepayers of this difficulty should be limited. And we therefore recommend that if DISCO is not able to provide the Board with an adequately supported computation, the

$47 million should be allocated on the basis of 50 percent to the Province and 50 percent to the ratepayers. And we leave that to the Board for consideration.

I will move on to the issue of financing and level of interest coverage. Ms. McShane testified that the test year revenue requirement should be sufficient to produce an interest coverage of 1.25. She also indicated that a ratio of 1.75 incorporating a higher level of net income would be necessarily in order for DISCO to move to a commercial capital structure typical of regulated utilities, with about 40 percent funded by equity. And this would be accumulated over time by accumulated equity through retained earnings.

Ms. McShane also testified that the debt guarantee fee paid by DISCO is reasonable because it is less than the gap between the interest rate available with a government guarantee and the interest rate that might be available to a similar entity with a commercial capital structure. At present, DISCO could most probably not obtain funding in the capital markets on its own, and at least not at any acceptable rate.

The Municipal Utilities conclude that the recommendation of this expert for the test year is conservative from a ratepayer standpoint, and that it is financially prudent for DISCO to work toward the accumulation of at least some modest level of retained earnings. We therefore recommend that the Board allow DISCO's proposal for the test year in this regard.

Now I would like to deal with export and interruptible sales. Firstly, export sales. In its June 19th 2006 decision the PUB summarized the issue of dispatch order of the NUGs as must run, and the impact of this arrangement on computed export revenues and the sharing of risk between DISCO and Genco. And I'm going to apologize, but I'm going to read a lengthy excerpt from that decision simply because the Board said it far more concisely than I could. And I will quote.

"The issue of the NUGs is relevant to the rate application because all of the energy and power arising from the NUG contracts are conveyed to DISCO under the vesting PPA. The vesting PPA requires that fuel consumption for the NUG plants be estimated using the modelling assumption that all of the NUG plants are dispatched on a must-run basis, irrespective of their economic merit order.

DISCO filed confidential information indicating that fuel costs would be substantially lower if the natural gas units were dispatched in economic merit order. The net benefit to DISCO in this circumstance would be a savings of a substantial sum of money.

The Board notes that a consequence of designating the NUG capacity as must run for in-province load, and thus assigning higher costs to New Brunswick customers, is that the lower cost capacity displaced by the NUG resources is available to compete in the export market. Because it can be priced lower than the NUG capacity in the export market, it is reasonable that a greater export sales volume results. It is also possible that larger export revenues will be earned depending on market conditions and transmission constraints.

Proceeds from export sales are shared between DISCO and Genco as outlined in the vesting PPA. DISCO's annual share is fixed as the third party gross margin credit on a five year forward looking basis, and Genco is at risk for annual variations within the plus or minus 20 percent of the set amount. That is, DISCO receives the set amount as long as the actual proceeds are within 20 percent of that amount. If net export revenues fall more than 20 percent below the set value, DISCO's share is reduced. However, if net revenues exceed expectations by more than 20 percent, DISCO receives one-half of the amount in excess of 120 percent of the set value.

It is important to note that the vesting agreement requires DISCO to pay the fixed costs associated with Genco's assets. This means that the long-term financial risks associated with owning the generation assets is borne by DISCO and its customers. In the short to medium term, some of this risk is transferred back Genco by the mechanism of the third part gross margin credit.

On balance, DISCO's customers carry more of the long-term risk associated with generation than the owner/investor.

This stands in stark contrast to the policy intent of the White Paper which proposed that investors, not customers, should be responsible for bad investment decisions.

Further, since DISCO assumes this risk, normally the most significant risk borne by a generator, it is reasonable to expect that DISCO would obtain a much larger share of the export benefits than Genco. On their face, the provisions of the PPAs relating to sharing of export benefits between DISCO and Genco seem tilted in favour of Genco." End of quote.

The Municipal Utilities concur that this summary last time applies equally this time, and we concur that it has significant negative implications for in-province customers of DISCO in terms of their costs and level of risk. In our view, 100 percent of the benefits associated with export of the output of generation units for which fixed costs are recovered in rates to in-province customers should be applied to reduce rates to in-province customers.

I will deal now with interruptible and surplus sales. A further inequity exists between in-province firm and in-province interruptible customers, as a result of this must run approach to dispatch of NUGs.

In response to an IR Disco said, and I quote, "Genco determines the sources of supply to DISCO by performing a complete economic dispatch of Genco's available resources such that the overall system production cost is minimized. Hydro generation being the most economic, is dispatched first in the economic dispatch order subject to contractual obligations for purchases, environmental regulations, system reliability and security, and unit operating constraints such as ramping rates, minimum loading, et cetera. Under certain system conditions not all the hydro can be fully dispatched to supply DISCO's vesting load. Any hydro generation that cannot be dispatched to supply DISCO's load will be dispatched to supply DISCO's interruptible load next, then to export sales last, with the benefits of export sales flowing back to DISCO through the third party gross margin credit.

Therefore, the benefits of hydro generation are passed either directly or indirectly to DISCO through third party gross margin credit. If hydro generation is dispatched to supply a portion of DISCO's interruptible load, the cost of that portion supplied by hydro generation is priced at zero dollars per megawatt hour." End of Quote.

Now it is our understanding that the must run status of the NUGs is included in the contractual obligations referred to in the response. The following testimony of Mr. Kennedy and Ms. MacFarlane provides further clarification of the attribution of zero cost hydro generation to in-province interruptible and export loads. To the extent that the hydro load -- sorry -- the hydro is dispatched to interruptible customers, is it a benefit to the interruptible customers. Answer, Mr. Kennedy: Yes. It's a low cost form of energy. It's a benefit to the interruptible customers. Question: How is hydro priced for export sales? Mr. Kennedy: Again hydro would find its way into the export after -- if it cannot be utilised by the in-province firm customer and the interruptible customer/surplus customer would find itself into the export market a few hours. And again it would be from a pricing point of view -- it could be at zero dollars at that time. Question: So who would you be selling hydro to for zero dollars to be used for the export market? Who would be the wholesaler in that case? Answer: It would be based on an export sale that would occur. It would basically form part of the generation cost net of any tariff or marketing cost. And it would be, you know, it would be based on the -- come back as a benefit if it is outside the range to the in-province customer. So it basically -- it provides pricing mechanism that sets and allows a sale either to happen from an export point of view. It could be going out to the export market around. It could be going to New England or it could be going to other jurisdictions. And then Ms. MacFarlane supplemented the answer. I just want to clarify it's not sold at zero. It's sold at the market price.

So apparently while export sales of zero cost hydro generation provide sales margins which accrue at least in part to firm in-province customers, the only benefit that such customers receive from such sales to in-province interruptible customers is the rate adder that provides a small contribution to fixed costs.

No change in the pricing mechanism for interruptible sales was specifically proposed in evidence, nor are the

Municipal Utilities proposing one at this time. However, we strongly recommend that the Board consider the impacts of such benefits in deciding whether anticipated increases in the levels of interruptible pricing should influence a decision on rates for large industrial firm supply.

Mr. Drazen in his evidence notes that large industrial interruptible service, which is priced on the basis of actual incremental fuel cost, is expected to increase by 41 percent over the charge in 2006/2007. However, in cross examination Mr. Drazen confirms his understanding of the basis of the interruptible rate.

Question: And do you agree with me, Mr. Drazen, that interruptible -- the interruptible rate is based on a pass through of costs from Genco? In other words, what the interruptible rate is is a fuel cost -- essentially a fuel cost with an adder, $3 on off peak and $9 on peak?

Answer. Right. It's the real time incremental fuel cost plus those adders, as you say. Question: So you would agree with me that as fuel costs go up, the interruptible rate would go up and as they go down the interruptible rate would go down. Answer: That's correct. Question: And you agree that in this application DISCO is not proposing any changes to the interruptible rate class structure at this point? Answer: Correct.

Now industrial customers, for their interruptible loads, have had the historic benefit of paying incremental fuel costs, and where these costs are low, or in fact costed as zero dollars, the interruptible loads continue to receive the benefits. Furthermore, the evidence has shown that interruptions, which provide the basis for this favourable rate treatment, have historically been extremely rare.

It is not fair or appropriate that increases in fuel costs and the resulting increases in the costs of interruptible service should be used to justify the continuation of an inappropriately low revenue/cost ratio for industrial firm loads.

Concerns have also been raised that the Point Lepreau refurbishment will contribute to an increase in incremental pricing to industrials and also increase the probability of interruptions. Under these conditions industrial customers may wish to make firm some loads that are currently interruptible.

This would impose on DISCO the obligation to contract for firm capacity to serve them, and an increased requirement for firm capacity will increase costs to all customer classes. Under present conditions of the rate, the customers could elect firm service for period when it is beneficial to do so, and return to interruptible service at such time as incremental fuel costs and probability of interruptions decrease.

It is not appropriate that any class of customers should be able to move back and forth at will between rates in order to gain a temporary advantage if such movement results in negative impacts to other customer classes.

The Municipal Utilities therefore support implementation of conditions on interruptible service to restrict such behaviour. These would include a suitable notice requirement, for example, two years, for conversion of interruptible loads to firm, as well as a minimum period for firm service before conversion back to interruptible service would be permitted.

I would now like to speak directly about firm class rate increases. In closing argument on behalf of the Municipal Utilities made in the 2005 CARD hearing, DISCO proposed fixing rates to establish a revenue/cost ratio of 1.05 percent for the wholesale class and .95 percent for the industrial class. Our stated position on ratios of revenue to cost was as follows. And I will quote.

"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 one 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 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 it states: The province will direct the crown utility to eliminate over time cross-subsidization between customer classes.

In our opinion, setting the target revenue to cost ratio at '95 percent without any policy consideration is a subsidy by any other name.

Much of the justification at the hearing for setting the rates for industrial at .95 and wholesale at 1.05 revolved around the fact that studies are not 100 percent accurate. 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 move towards unity.

I have quoted at length for one reason. Our position is unchanged. The target should move towards unity always. In the course of these hearings specific customer groups have suggested that for reasons of economic and/or social policy they should not pay the full cost allocated to them. In this era of large energy cost increases, we recognize and are deeply concerned by the effects on all New Brunswick customers. However, we believe that these effects are best addressed through government policy and programs which could allocate the cost of subsidies, if any, to those best able to afford it. Imbedding subsidies of any kind, whether to industrial customers or to low income residential customers, in the electricity rates, would cause the costs to be allocated among other customers on the basis of electricity consumption. This is not a fair or appropriate basis.

We believe that the Board's prescribed bandwidth of .95 to 1.05 should be interpreted as a means of prioritizing the need for relative rate adjustments among classes, and not as a zone in which DISCO has discretion to give or require inter-class subsidies. The priority in relative adjustments to rates should be to bring those classes outside the bandwidth to a ratio within the bandwidth.

As to relative adjustments to classes already within the bandwidth, in our view a policy to eliminate over time cross-subsidization between customer classes entails an absolute minimum that no class revenue cost ratio be adjusted in a direction away from unity by a rate change different from the system average.

As to the magnitude of such directional changes, we concur with the concern expressed by the Public Utilities Board in its 2005 CARD ruling where they expressed the following: We note that certain customer classes have revenue to cost ratios that remain outside the .95 to 1.05 range and are disappointed that NB Power did not make more progress in this area in the time since 1992.

In its evidence listing the principles applied to the rate design, DISCO has included the following as one of its priorities. Reduce -- or one of its goals -- reduce cross-subsidization between classes by bringing the classes that fall outside the revenue to cost ratio zone of reasonableness of 0.95 to 1.05 closer to the target zone.

Our recommendations flowing from this general position would include an increase greater than the system average for the firm large industrial class, and an increase below the system average for the General Service class. DISCO has in fact proposed an increase of 7.4 percent for firm industrials and 5.3 percent increase for General Service, and an increase of only .5 percent for street lights and unmetered loads. While these adjustments are directionally correct, the Municipal Utilities would support a larger relative adjustment in the case of both General Service 1 and industrial classes.

CME has taken the position, through Mr. Drazen's evidence, that a more appropriate cost allocation approach would reduce the large industrial class' allocated costs by $23.9 million as compared with DISCO's CCAS, so that with the system average increase of 6.4 percent, that class would move to a revenue cost ratio of '97 percent, which is within the so-called zone of reasonableness.

It is indisputable that the revenue cost ratios of all customer classes, and the industrial class in particular, are sensitive to the methodology chosen for the classification of generation costs. However, the Board has been clear in prescribing that the previously approved methodology be applied in determining rates in this proceeding. It is therefore not relevant that some other methodology would produce a different result.

Additionally, it should be considered that the proposed rate increase is applicable to firm loads, whereas the revenue cost ratios computed by both DISCO and Mr. Drazen incorporate both firm and interruptible sales. Mr. Knecht's analysis separates these two services, demonstrating that the revenue cost ratio for large industrial firm service is actually only .888, less than the .91 shown in DISCO's CCAS tables.

In commenting on the rate increase proposal, Mr. Knecht says, and I quote, "The large industrial firm transmission rate class exhibits a revenue cost ratio of .88 percent at present rates, and yet DISCO proposes to assign it a rate increase of 7.4 percent, which is only slightly above the system average increase of 6.4 percent, a multiple of less than 1.2-to-1. Under DISCO's proposal, the revenue cost ratio for the large industrial firm transmission rate class increases only marginally."

In the view of the Municipal Utilities, a class of service with a revenue cost ratio of .88 based on a stable methodology approved by the Board, should receive a rate increase that will make measurable progress in bringing it to within the prescribed bandwidth of .95 to 1.05.

With regard to the General Service class, which is also outside the zone of reasonableness, Mr. Knecht says, and I quote, "On average the General Service rate classes exhibit a revenue cost ratio of 125.4 percent at present rates in DISCO's CCAS. DISCO's proposed increases result in an average percent increase for that class of 5.3 percent, which results in a decline in the revenue cost ratio to 124 percent. At that pace it would take over 11 rate proceedings before General Service rates would be within the Board's target revenue cost ratio range of 95 to 105 percent. As the General Service classes have been paying rates that are far in excess of allocated costs since at least 1992, such progress is meager at best."

The Municipal Utilities concur with this analysis and that a more significant step in reducing the over-contribution of General Service customers for the test year is only equitable. The appropriate amounts of the change are clearly a matter of the judgement of the rate designer as to the level of the increase that will not cause rate shock to the customers, contributing higher revenues in order to offset relative reductions to other classes.

We believe that the rate changes proposed by Mr. Knecht are not unreasonable, but that in all events the revenue cost ratio of the General Service I class should be reduced below 1.2 as a result of the Board's decision in this proceeding.

Now that concludes our argument on issues for the test year. I will now go into issues which we hope will be helpful in the Board developing its final decision, as these matters go more to policy. And hopefully the Board will give some direction on these issues as we are about to outline.

Now while we accept that the primary purpose of this proceeding is to approve rates and charges for the test year, take issue with DISCO's apparent position, often repeated in the interrogatories, that issues affecting regulatory treatment beyond the test year ought not to be considered.

The following are issues of regulatory practice upon which we would like to offer our recommendations to the Board.

First is with respect to allocation of CT and emergency generation costs. The PUB in the previous CARD hearing and later rate decision selected a small number of aspects of the approved cost allocation methodology for change in the future.

And I will quote. "DISCO allocated costs for our combustion turbines and emergency power purchases to the customer classes on the basis of the winter heat load. Mr. Knecht recommended that these costs be allocated on either a peak demand basis or an energy basis, as all customers benefit. The Board considers that these costs should be shared by all customer classes but will not require a change for the 2006/7 as the amount of the cost is small. The Board directs DISCO to file a study at the time of the next general rate application that provides an analysis of whether peak demand or energy is the most appropriate method to use in allocating these costs."

Now in response to this order a study was in fact undertaken. And the authors -- this is the Concentric study -- reported as follows.

"DISCO's purchases of CT and emergency power are made on a cost per kilowatt-hour basis at the time of unanticipated peaks. It can be argued that such resource requirements are not exclusively caused by any one class, subclass of users. Each class contributing to the load during the peak period is proportionately responsible for the costs. From review of DISCO's evidence, it appears that the CT and emergency power supplies are not contracted for specific customer classes, nor are there any offsetting cost adjustments made in the allocation of the remaining supplies. Therefore, it does not seem to be appropriate to allocate CT and emergency power costs to specific classes of customers."

Now the Municipal Utilities concur with the opinion of the Public Utilities Board and Concentric that DISCO's approach to allocating these costs is inappropriate. We therefore request that the Board order DISCO to include a specific proposal for a more appropriate allocation of these costs at the time of the next generic review of cost allocation methodology, or if earlier at the next occasion on which any change in cost allocation methodology is submitted by DISCO for approval in connection with a general rate proceeding.

Now an area of concern in these proceedings, and we believe the 2005 CARD hearings, was the issue of affiliate relationships, and especially so between the relationship between DISCO and the generation companies to the PPAs and Holdco.

Now the PPAs are of particular concern to us. Because generation represents such a major cost component. In the CARD hearing, and again to some extent in this proceeding, parties took the view that information on underlying costs is necessary in order to judge prudence and upon which to base an allocation to customer classes.

Affiliate relationships are an issue of concern generally to regulators and utility customers across very many jurisdictions. And this is because of the potential for inappropriate transfer of benefits from the regulated utility, and thus the ratepayers, to unregulated utilities and the shareholders.

Such inappropriate transfers of benefits can be in the form of biased transfer pricing of goods and services, preference in supply relationships or preferential access to information that is valuable in a competitive context.

There are many U.S. states and regulators have required specific rules to be established for affiliate transactions in order to prevent such abuse. Ontario has also established such rules. And several years ago there were major generic hearings in Alberta to review the pricing of affiliate services.

If the current structure of the NB Power group of companies remains in place, so that DISCO has unregulated affiliated with which it does business and shares costs, we recommend that the Board consider establishing rules for determination of transfer pricing and benefits between affiliates. And we will leave the Board with that consideration.

The next issue we would like to leave with the Board for consideration is the issue relating to the filing, or in this case nonfiling of actual results and projections beyond the test year.

DISCO again has pointed out repeatedly in this proceeding that its rates are set on the basis of a forward test year and never trued up to reflect differences from forecasts that actually occur.

Once the test year revenue requirement is established, any variances are the risk of the taxpayer. Therefore, DISCO has argued that actual results are not relevant to the decisions to be made in the proceeding, and filed some historic actual financial results only in response to IRs.

The Municipal Utilities believe that the ability to view the test year projections alongside some actual historic results, and also to compare the forecasts of prior years with actual results, allows intervenors and the Board to make some judgements about whether the cost forecast is reasonable and to identify the specific cost items that either diverge from the historic trend or were badly forecast in the past.

We therefore recommend that for future hearings the Board require DISCO, as part of its main evidence filing, to provide a minimum of two years of historic actual data, and the forecasts or budgets done for those years at the same level of detail as the test year information.

I will move on to the last substantive item before moving to a conclusion, and that is the review of cost allocation methodology.

The Board has requested parties to address this argument, which really relates to CME's motion. We expressed this earlier, perhaps not as clearly in September, but we will express it clearly now, we hope.

The Municipal Utilities do not perceive a need for a CARD hearing at this time. In our view, the 2005 proceeding was comprehensive. As well as examining DISCO's study in great detail, the PUB had before it several specific recommendations for changes in methodology, including changes to the approach for classification of generation costs.

These latter proposals were rejected after consideration of the industry structure and the manner in which costs flow through from Nuclearco and Genco to DISCO via the PPAs.

The Municipal Utilities acknowledge that cost allocation is an evolving exercise and that improvements provide value to customers. We are also of the view that once a methodology has been well tested in the hearing process, the values of stability and predictability are preserved by keeping that methodology in place until there is strong reason to reassess it.

In our view, strong reason would be limited to two following situations. Firstly, where there are changes in the underlying cost structure -- and we are not talking cost level, but the underlying cost structure of the utility -- that would not otherwise be appropriately reflected by the methodology.

Or secondly, the availability of new data, technology or analytic tools that allow an existing estimation approach to be replaced by an approach that tracks cost causation with significantly more accuracy.

And example of the former dealing with cost structure would be the opening of a competitive hourly market for electricity. That would certainly be evidence of a need for perhaps a new methodology to be looked at.

As an example of the latter would be if a system were in place that would allow specific assets to be identified with the individual customers that they serve.

As there has been no evidence that either of these conditions or anything like them have been satisfied in comparison with the status quo at the time of the 2005 CARD hearing, our view is that there is no present need for a CARD hearing.

Our recommendation is that the CARD hearing be deferred until the Board, either in a future rate hearing or as a result of evidence brought forward by a party has identified a reason for the review to take place.

Now I must say in listening to Mr. MacDougall, who does put forth an argument that the Board on its own motion could bring such a hearing to come to pass, I'm not going to take issue. I think their argument is certainly that the Board could do that, there may be contrary arguments.

We didn't look at the Board's jurisdiction from that perspective. We looked at it a little more from the perspective of DISCO or an aggrieved party.

And I would say that while the Electricity Act does not provide explicit authority for the Board to initiate such a proceeding, without a rate application or a complaint, it clearly allows the Board to deal with it during a rate hearing or upon a complaint of an aggrieved party.

And we believe that if the conditions exist as such, that either DISCO or an interested party would be before the Board, DISCO in their case either seeking an amendment to their CARD methodology, or an aggrieved party. And the Board would certainly have the authority in that instance to initiate a rate hearing if they were convinced. And it would be our suggestion that they should only do so if one of those two underlying fundamental changes has occurred.

Now I'm just going to briefly summarize our recommendation. In conclusion, regarding the cost allocation methodology to be applied in 2007/2008 test year, the approved cost allocation methodology approved by the PUB in 2005 should be a basis upon which appropriate rate class increases for this year are considered.

Regarding the load forecast we urge the Board to order that DISCO, in bringing forward revisions to its long-term forecast methodology, clearly explain the interactions between their forecast model, both long-term and short-term, and set out for the Board's approval an approach to short-term forecasting, so that the apparent discrepancy in growth rates can be rationalized.

Regarding sharing of the PDVSA settlement, we have already made our proposal. And we strongly recommend that if the Board is as unclear as to what actually should be done, as most of the intervenors appear to be, in terms of what the numbers tell us, then if this Board is not able to come to an adequately computed solution of the problem, that the only fair thing to do is to share on a 50/50 basis the money between the Province and the ratepayers.

Regarding the interest coverage ratio, we would recommend the Board approve DISCO's proposal for the test year. The benefit of export sales in our view, for the reasons we earlier stated, 100 percent of the benefits associated with the export of the output of generation units for which fixed costs are recovered in rates to in-province customers should be applied to reduce rates to in-province customers.

Regarding the pricing of interruptible sales, we do not propose there be any change to the basis of interruptible rates at this time. However, it is our position it is not fair or appropriate that increases in fuel costs and the resulting increases in the cost of interruptible service be used to justify the continuation of an inappropriately low revenue cost ratio for industrial firm loads.

Regarding terms and conditions of the interruptible rate we support implementation of conditions in interruptible service to restrict movement of loads between interruptible and firm service. Such conditions would include a suitable notice requirement for conversion of interruptible to firm as well as a minimum period of firm service before conversion back.

Regarding relative rate increases to the classes of firm service, we would once again repeat, the move toward unity should supersede the notion that there is a zone of reasonableness.

Specifically we recommend industrial firm rates be increased and General Service I rates be decreased by a sufficient amount to make significant progress in moving the revenue cost ratio of these classes toward 1. We consider the recommendations of Mr. Knecht in this regard to be reasonable. But in no event should the revenue cost ratio for the General Service I class continue in excess of 1.2.

If subsidies of any class are determined to be required as a matter of economic or social policy, that they be provided through government programs funded through taxes and not as imbedded subsidies in the structure of electricity rates.

Regarding the allocation of CT and emergency generation costs, we request that the Board order DISCO to include a specific proposal for a more appropriate allocation of these costs at a time of the next generic review of cost allocation methodology, or if earlier, at the next occasion in which any change in cost allocation methodology is submitted by DISCO for approval in connection with a general rate proceeding.

Regarding transaction between DISCO and affiliates we would recommend, as we have just recently stated, that the Board consider establishing rules for determination of transfer pricing for affiliates.

Regarding the provision of information in future rate approval applications, again we would ask that a minimum of two years of historic data be submitted at the same detail level as their forecast at the time of the next submission.

And dealing with the CARD hearing, we have just expressed the view we hold clearly that we don't believe that a CARD hearing should be held at this time or at anytime in the near future, but that the Board would certainly have the jurisdiction upon request of an aggrieved party to make such a ruling and deal with it at that time.

In conclusion, I would once again like to thank Mr. Chairman and the Board for all of your patience. And I would like to thank the Applicant and the intervenors for their courtesies and the clear way in which they brought forth the evidence in this proceeding.

Thank you. That is all I have unless there are any questions.

CHAIRMAN: Any questions from the Board? Mr. Barnett?

MR. BARNETT: Mr. Zed, if as has been stated publicly there is no rate application for the next several years because the utility, distribution company can proceed under section 99, the CPI rule, what would your position be in regards to a CARD hearing in a period say of several years when there is no application before the Board?

MR. ZED: Well, I think clearly under the Act -- and Mr. MacDougall is of the opinion that the Board could initiate a hearing on their own, and I will leave that for Mr. MacDougall.

But I think clearly the provisions of the Act provide that the Board, upon complaint of a party, can make any order that it is entitled to make under the Act. And one of the orders the Board is entitled to make under the Act is with respect to a cost allocation and rate design hearing.

So I think the Board has clear jurisdiction. If the Board were to follow our recommendation, should either -- take, for example, if there were an underlying change to the cost structure of DISCO. Then if there were such a significant change, it is hard to imagine that DISCO wouldn't of its own motion be back before the Board seeking some direction.

Or if it were that dramatic, then there would be a number of customer classes presumably who would have reason for a complaint. If they had no reason to complain then there is no reason to come before the Board.

But if they were aggrieved by the change in cost structure, then it is up to the individual members of the class to get together, come to the Board, file a complaint and say because of significant changes to the cost structure of DISCO, the cost allocation methodology adopted in 2005 is no longer relevant. And therefore the Board could order, on that complaint, could order that a CARD hearing be initiated.

Furthermore if the technology, which is available but not widespread, had become widespread, and it were easier to track costs directly to customer classes, cost to use and match it up so that the amount of estimation that goes on now became unnecessary and noticeably very inaccurate, then you would probably have -- it is hard to imagine you wouldn't have one or more customer classes that would be complaining they were being unfairly subsidizing other classes.

They could then come -- if DISCO still decided to do nothing, which I can't imagine, then any of the customer classes could come before the Board and say because of this new technology it is apparent that in our case we are no longer at 1.05, we are at 1.30, or another class is at .75. Then it would certainly be up to the ratepayers to come before the Board. And I would think the Board in those situations would have the jurisdiction to come forward and order a hearing.

But again, should any of those things occur, I couldn't imagine that DISCO would not be before this Board seeking the very same thing. Because it would have a dramatic impact on them as well.

MR. BARNETT: Just to follow on a question, do you see any merit in disassociating a CARD hearing from a rate application?

MR. ZED: Well, I think it has been our position that really it is very difficult to do an application unless you know the methodology that is going to be approved. So whether the CARD hearing -- I think it is better to be done separately. It is better to be done first.

Now whether it is done, you know, as a result of an application for a rate increase and then it is decided that there be a generic CARD hearing to precede the rate application, you know, I won't quibble about that.

But I think the main thing is, from an intervenor's point of view, is that the CARD hearing, if there is one to be held, that it be held prior to.

Now the Applicant may say well, that is fine, but that may necessitate us going back to the drawing board with our application, and it may cause us timing issues. And that may have been part of the argument that my learned friend brought forth this time. And I guess I would have some sympathy for them in that regard.

So with respect to the Applicant's position, it may be fair to do a generic CARD hearing in a vacuum, so that going forward to an application they would have all the information, and they would know what the rules of the game were essentially before they developed their application.

MR. BARNETT: Thank you. One last area. I would just like to explore a little bit more clarification. And it relates to the filing of historical data.

Just so I understand, are you looking at this two-year historical. Would that be for example a year where there was complete information, a year that was in progress for example at the time an application was being made and the test year?

Or are you looking at two years of complete historical data with actuals, as well as the year in question? The question --

MR. ZED: I think we are looking for two full years of actual historic data.

MR. BARNETT: So it wouldn't be estimating the last quarter or something like that of the year that -- it would be one of the two years you are looking at?

MR. ZED: Well, except -- and I will be guarded in my comment. Because sometimes more information, for example in the case of the PROMOD runs, wasn't necessarily -- sometimes you get so much information that it is not of great use to you.

But I think if we had two historic years plus the year in progress, then that would be a fair comparison.

MR. BARNETT: So its total would be four, just for clarity --

MR. ZED: Yes.

MR. BARNETT: -- with the test year?

MR. ZED: With the test year.

MR. BARNETT: Thank you, Mr. Zed.

CHAIRMAN: Mr. Zed, just a question on your recommendation with respect to the PDVSA settlement. If I understand what you are suggesting, it would be that the $47 million that was not part of the deferral account, in the event that there was not sufficient evidence to determine how that should be divided proportionately, I think you are suggesting a 50/50 split between the shareholder and the ratepayer?

MR. ZED: That is exactly what we are suggesting.

CHAIRMAN: And what you didn't indicate was whether or not that should be applied to the test year revenue or whether it should be part of the deferral account or should it be applied over the next few years.

Do you have any comments as to, if the Board were to go along with that type of a suggestion, just how it should be applied?

MR. ZED: Mr. Chairman, I mean, to be fair, the sooner the better it is applied would be better for ratepayers obviously. But you know, we will leave it to the Board's consideration.

I mean, obviously it is cash received. And it should be applied. Our position would be that it should be applied to the test year.

CHAIRMAN: Thank you. Well, thank you for your submission on behalf of the Municipal Utilities, Mr. Zed.

Dr. Sollows?

DR. SOLLOWS: Mr. Chairman, respected Board members, thank you for this opportunity to summarize my views and suggest options for you to consider in your decision on this matter.

My remarks will have three main themes, the revenue requirement, including the matter of the power purchase agreements and the scope of your discretion in its determination, the class cost allocation study and its relevance to your decision, and the available residential rate designs and their implications.

I spent very little time on the matter of the revenue requirements. So my comments and guidance will be brief.

The NB Power group of companies is just that, a group of closely related companies. These companies do not have an arm's length relationship between one another. They share senior staff, a single board of directors and a single owner in common.

This relationship is such that you as the regulator must be particularly diligent in the discharge of your duties.

In the normal course of business between arm's length contracting parties, the divergent interests of the parties works to ensure that contractual arrangements are mutually beneficial and appropriately balanced.

In such circumstances the regulator is and should be predisposed to respect the contractual obligations of the regulated company.

It follows that you could, and I think should, simply accept the provisions of PPAs between DISCO and any independent and unrelated energy suppliers.

The circumstances of this matter are not the normal course of business, however. DISCO is clearly not at arm's length from Genco, Nuclearco, Coleson Coveco or Holdco.

And you cannot rely on these parties to instruct the appropriate balance between the interests of the companies. It falls to you to make that determination.

It is no secret that your predecessor board reviewed the PPAs in some detail and reported the results of that review in its decision of June 2006. It is also no secret that your predecessor was prescribed by legislation from altering the terms and conditions of the PPAs.

A full and fair reading of the June 2006 decision will clearly show that the previous Board would likely have set aside certain provisions of the PPAs had they had the right to do so.

Mr. Chairman, respected panellists, you have already ruled that the legislated requirement to accept the PPAs as written is spent. You are certainly not encumbered in any way by the previous Board's opinions of the PPAs. You must reach your own decisions in the matter.

I only request that you do make a deliberate determination on the matters raised in the June 2006 decision of the Public Utilities Board and any other matters you may have identified in your own review of these documents, and settle matters now that you have the power to do so.

In particular I would ask you to consider the fact that DISCO is required to pay a higher price to lease all of Genco's capacity under the vesting agreement and is effectively required to lease back a portion of the capacity to Genco for an export benefit that represents in effect a lower price.

Consider this and ask yourselves one question. Is this the kind of contract provision that would likely arise between parties at arm's length? If you believe it is, you should let it stand. If you think it is unreasonable, you should adjust the revenue requirement for DISCO accordingly.

My final comment on the revenue requirement relates to the 95 gigawatt-hours reduction in seasonal energy load to bring the forecast in line with recent experience.

Seasonal energy is expensive energy. And I have no doubt that the adjustment is material in the context of DISCO's overall revenue requirement.

I agree that DISCO's sales forecast should be similarly reduced. And it is confirmed by my own analysis that DISCO's energy sales forecast for residential customers is not really in any way responsible for the excess.

It follows that the energy sales estimates for General

Service and wholesale customers are principally responsible for the overestimate, with a small portion attributable to small industrial customers.

You would not go far wrong if you apportioned the 95 gigawatt-hours reduction in sales between these three classes in proportion to DISCO's estimates for their seasonal energy sales.

I turn now to the issue of the class cost allocations. In respect of the class cost allocation study, I would draw your attention to two matters, one that is quite specific and one that is much more broad and general.

On the specific matter, and this echoes the concern of counsel for the Municipal Utilities, the customer cost allocation or class cost allocation study filed by DISCO in this proceeding seems somewhat inconsistent in its treatment of peaking generation costs.

I understood that the CCAS was to be based on an allocation of generation fixed costs at 60 percent to energy and 40 percent to demand. It appears that 1.4 million of costs related to combustion turbine and emergency purchases of energy are not allocated in that way. Instead they are allocated separately to only the residential, General Service II and wholesale classes.

This treatment is also inconsistent with that made for seasonal peaking energy derived from NB Power's hydro plants, which has zero energy costs.

There are two obvious ways to resolve this consistency. And here I go further than the Municipal Utilities would have you go.

If the Board wants the class cost allocation study to reflect the previously approved methodology, it should simply reallocate the $1.4 million to all classes based on the 60 percent energy, 40 percent demand split.

If instead the Board accepts DISCO's deviation from the approved CCAS as described in schedules 5(1) and 5(1)(a) of that document, it should allocate all seasonal peaking capacity in that way. This would include the significant amount of zero cost energy from Genco's hydro plants that is available to meet seasonal energy loads.

For the sake of simplicity and consistency, I suggest that the Board should follow the first course of action and not the second.

On the more general matter, it will not have escaped the Board's notice that some intervenors are concerned that the allocation of generation fixed costs, 60 percent to energy and 40 percent to demand, is not appropriate.

I think it is fair to say that these intervenors believe a smaller allocation to energy and a larger allocation to demand would be more appropriate.

In my opinion DISCO attempts to meet this concern and still meet the letter of the Board's order to use the approved class cost allocation study, by arbitrarily setting its revenue recovery well below cost for the large industrial class. This is the class that would likely see the largest reduction in costs under a revised allocation between energy and demand.

The basic principle that Bonbright brings to bear on this matter is simply stated. In the first instance all fixed costs of generation should be allocated on the basis of the user's contribution to the peak demand on the system.

He clearly allows and it is generally agreed that some portion of the fixed costs should be allocated to energy in certain circumstances.

For example, to the extent that fixed costs relate to investments that result in lower fuel costs for the system as a whole, most would agree that at least a portion of those fixed costs should be allocated to energy.

What portion? Even disinterested people may reasonably disagree on that point. So it goes without saying it will be an issue of some contention in most proceedings of this type.

We all may disagree on the exact fraction of generation fixed costs that should be allocated to energy. But one thing is quite clear from the literature. We start with an allocation based on the contribution to peak demand and work from there.

The decision as to how far to go from that starting position clearly and necessarily lies with the Board. So how, you might ask, did the 60 percent energy, 40 percent demand split come to be?

It was decided in a hearing in the early 1990s in which large industrial customers were ably represented by Messrs. Neil McKelvey and Rodney Gillis. That sounds a little bit like the odd couple. But in fact they represented two different groups of clients in that proceeding.

Evidence was heard on all sides. And people such as you decided that NB Power's proposal at that time, the 60 percent energy, 40 percent demand split was appropriate. This begs a question. How did NB Power arrive at such a proposal? I really can't say for sure. But I do note that it bears a striking resemblance to DISCO's average load factor in past years.

I can say with some confidence that a company of engineers would find it quite natural and reasonable to allocate costs on the basis of load factor irrespective of and perhaps even in spite of what any economist might have to say about it.

I can say this because it is close to what I would do if I faced the same allocation problem and want to dispose of the matter without spending days or weeks or even months pouring over the literature related to the allocation of joint and common costs.

The load factor results from dividing two numbers, the forecasted energy for the year divided by the energy that could be delivered if the system ran at the forecasted peak load 24 hours a day, 365 days for the year.

A 60 percent load factor means that all of the required energy could have been delivered at a steady load that is only 60 percent of the forecasted peak load.

So I can easily see how an allocation of 60 percent of fixed costs to energy and the remaining 40 percent to demand would arise.

That is not to say I would agree with it. No, I would argue that the appropriate split should be based on the capacity factor, not the load factor. Because it is the capacity that is most closely related to the fixed generation costs.

If capacity factor was just the annual forecasted energy divided by the energy that would be generated if all of the capacity ran all of the time, I would make a small allowance for reserve margin requirements at a run of the river hydro and probably arrive at a split that is closer to 45 percent energy and 55 percent demand.

Now I freely admit that this methodology would be just as wrong as the one based on load factor, from the perspective at least of the economic theory on the allocation of joint and common costs.

It would nonetheless, I submit, have two substantial merits. It would go a long way to satisfying the concerns of those participants who take issue with the existing allocation. And it would be comprehensible to both you and to the public.

Speaking as someone who has sat through a cost allocation hearing in a seat you now occupy, I'm acutely aware of two facts that seem to be sometimes forgotten by those who appear before you.

The first fact is that you, like me, are not expert in the matter of cost allocation. If it is to be your decision in the matter and not simply the ratification of one expert's opinion or another's, you need to know and understand the basis on which the decision is made.

The second fact is that you are like all judges in that you do not sit in a vacuum. If you are asked to take a decision like this, one that will result in a substantial transfer of costs from large industrial customers to residential and General Service customers, you will need a body of evidence that clearly and unambiguously supports you in that decision. That evidence must also be intelligible to the many members of the public who, like you, could be called upon to evaluate it.

So what should you do? If you think that yet another cost allocation hearing in the customary style will leave you in a position to decide the matter, then you should go for it. I would be reluctant to do so.

Instead, and if the many lawyers around the table would let me get away with it, I would invoke that a regular and so-called principle of gradualism, mix it with an ample serving of judicial discretion and change the allocation in the direction we all know it must go, perhaps to 55 percent energy and 45 percent demand in the decision arising from this proceeding. This would be reasonable and quite supportable in the context of recent load factor history. I would then seek an alternative forum to resolve as many of the issues related to this matter as possible.

During the 1990s I participated in Environment Canada's Atlantic Coastal Action Program, Saint John Multistakeholder Group. This group had and has some of the same stakeholders that appear before you now, including J. D. Irving, Irving Oil Limited, Conservation Council of New Brunswick and others.

The main deliverable after the first five years of operation was a so-called Comprehensive Environmental Management Plan for the Saint John Area Watershed. It was my privilege to chair the committee that wrote that plan.

In the end it was quite remarkable how much common ground we could find between organizations and interests that at the start of the process would barely sit in the same room together. I have every confidence that such a process would be a valuable precursor to any formal hearing you might wish to hold on cost allocation.

With respect to residential rate design, perhaps I have already said enough in my evidence about that. But I will try to summarize my views and identify what I think are the limits to your discretion that can be justified by the evidence in the matter.

It really comes down to how confident you are in the bases of the indications that are contained in the cost allocation study. If you really believe that customer costs amount of $22 per month that is indicated in the study, I respectfully suggest that you have a duty to set the monthly service charge at that amount, quite irrespective of what DISCO, CCNB, Mr. Peacock or I might otherwise suggest.

DISCO apparently doesn't believe the indication because it elected to maintain the current service charges, equivalent to roughly $20 per month.

Mr. Knecht found a different value, something close to $15 per month, if I recall. And Mr. Peacock would have you set it at $13 per month. I would set it rather low but no lower than $10 per month, in keeping with Bonbright's views on the matter.

I cannot help but note that much of the reason for the discrepancies between these numbers relates to the allocation of the minimum system costs to the customer category.

As Bonbright notes on page 348 of his text, to which cost function does it, the minimum system cost, then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of the long run marginal costs.

But the fully distributed cost analyst dare not avail himself of this solution, since he is a prisoner of his own assumption that the sum of the parts equals the whole. He is therefore under impelling pressure to fudge his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.

Having decided the matter of the monthly service charge -- and I think, certainly looking around North America, you could go anywhere from 5 to $25 without any question. It is your judgment. I would suggest that you had implicitly decided the matter of the appropriate rate structure.

If you accept the cost allocations of the customer class allocation study which were $22 per month customer cost and 6 1/2 cents per kilowatt-hour of energy, and set the service charge at a high value, at or close to $22 per month, my analyses demonstrate that a flat rate is the appropriate design.

As you lower the service charge and the allocation to customer costs, the appropriate design shifts toward an inclining block design for the vast majority of residential customers.

For some of the very largest customers in the class, the summer peaking and flat use customers, both this flat rate and the inclining block rate will recover more than is reasonable under a cost of service model.

For this reason I suggest you go no further than setting a flat rate in this proceeding, and only do this if you place what I will call a collar on the rate increase in the manner described in my prefiled evidence in my response to PI IR-5, Question 2.

I would also note that there is no substantive evidence to support a differential in the monthly service charge between urban and rural customers, and that the historical record of billing data shows that rural and seasonal customers have lower peak coincident demands than urban customers.

It follows that the cost of service for rural and seasonal customers may in fact be lower than that of urban customers.

Finally, Mr. Chairman, and respective Board members, I will remind you of the old saying, and pardon my Latin, De gustibus non disputandum est. If matters of taste are indeed beyond dispute, you might well consider what value there is in doing cost allocation and rate design as an art as opposed to a science.

Thank you for your time and attention to these matters. I wish you all a very merry holiday season.

CHAIRMAN: Thank you, Dr. Sollows. Any questions from the Board?

Thank you again for your participation and your presentation here today.

The Board will take about a 15-minute recess. And then we will hear from the Public Intervenor.

(Recess - 10:30 a.m. - 10:45 a.m.)

CHAIRMAN: Mr. Theriault, are you ready for your closing argument at this time?

MR. THERIAULT: Yes, I am, Mr. Chairman. Mr. Chairman, Board Members, good morning. There are disadvantages and advantages to going last. One of the disadvantages is length. So in fact I feel a bit like an airline pilot speaking to passengers before embarking on a long flight. Please sit back, relax and enjoy the flight.

Mr. Chairman, the rate application is before the Energy and Utilities Board pursuant to section 101(1) of the Electricity Act, which reads, "If a change in the charges, rates or tolls for its services would exceed the amount under Section 99, the Distribution Corporation shall make an application to the Board for approval of the change, and shall not make any change until it has received the Board's approval."

The reference to Section 99 refers to the ability of DISCO to change its targets, rates and tolls by three percent or the percentage change in the Consumer Price Index, whichever is greater, without application to the Board. The Board must make its decision on the application before it based on section 101(5)(a) of the Act, which reads, "the Board at the conclusion of the hearing 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."

It is clear from these two sections that DISCO has a duty to apply for changes to its rates, tolls and charges, and the Board I submit has a duty to confirm that such changes are just and reasonable.

Under the standard of just and reasonable it is the result reached, not the method employed, which is controlling. In other words, it is not the theory but the impact of the rate order which counts.

Under the Electricity Act, DISCO has the responsibility and the onus to demonstrate that it has acted prudently with respect to decisions that impact its revenue requirement. An excessive cost that is imprudent cannot be part of a just and reasonable rate. Nor can a benefit that would otherwise result in a reduction in the revenue requirement be set aside without consideration of the prudency of such action.

NB Power's first rate application was made before the Public Utilities Board in 1991. In 1993 changes in the legislation gave the utility the ability to raise rates by up to three percent in any one year without making an application to the Public Utilities Board.

Between 1993 and 2005 the utility had cumulative losses of over $300 million. These losses were covered by borrowing on the capital markets and then by charging the interest costs to the ratepayers. When deficits did not permit the payment of interest charges, the utility simply borrowed the money to make the payments. No where was the taxpayer ever called upon to examine and ultimately fund the deficits that the utility ran up in its attempt to avoid regulatory scrutiny.

In 2005, under the provisions of the Electricity Act, previously quoted, DISCO made an application before the Public Utilities Board. For that application Section 156 of the Act applied.

While Section 156 was deemed to be in effect for the 2005 rate case, the Applicant divulged considerable information about generation costs, NUG contract costs, performance measures, PROMOD data, service level contracts, et cetera.

This information was ordered to be released by the Board on the basis that while the asset valuations and costs were to be deemed prudent for the first rate case, that did not mean that the information could not be released to all parties to the proceeding. As part of the 2005 rate application, the Public Utilities Board ruled that Section 156 would have no effect following its decision in the case.

On April 19th 2007, DISCO made the current application that is currently before this Board. As part of its April 19th application to the Board, DISCO made an application under Section 40 of the Energy and Utilities Board Act for interim rate relief. The application sought a 9.6 percent increase for all customer classes.

Conventional regulatory practice requires that the Applicant make a prima facia case for interim rate relief. I had argued that at best the utility had made a case for only the fuel component of the increase. The Board ruled otherwise and an order granting the full interim increase was granted.

As part of the rate case process I filed 86 interrogatories, many with several subsections. These interrogatories were filed in a belief that the information requested would aid in the preparation of my intervention, and that this information was appropriate and necessary to determine the prudency of DISCO's revenue requirement.

At this point, Mr. Chairman, I find it necessary to comment on the interrogatory process in this proceeding. I believe it is appropriate to note that the Applicant's approach in responding to interrogatories dispels any illusion that the President of DISCO understands the term open and transparent process of which he has loudly proclaimed himself in favour.

On the other hand, and to be fair to the President, he did indicate that he accepted no responsibility for the application or the conduct of the Applicant before this Board. The interrogatory process was neither open nor transparent. Quite the contrary. It was replete with delays, failures to meet filing schedules, failures to respond, refusals to respond, responses that were non-responses and unnecessary claims for confidentiality.

I submit none of this contributes to an understanding of the nature of the application before this Board, nor does it assist intervenors whose job is to inquire as to the prudency of the revenue requirement that you as a Board must approve. It is not an overstatement to say that the interrogatory process was the most protracted and frustrating part of this rate case, and that the Applicant's approach to the interrogatory process contributed substantially to the delays experienced by all.

Now, Mr. Chairman, there are four main issues, I submit, before this Board. They are first of all the management and the costs of the PPAs, secondly the PDVSA settlement, thirdly, the revenue requirement and adjustments and confirmation of the revenue requirement, and finally fourthly, rate design. And I would like to speak to each of these items in turn.

And, Mr. Chairman, at the end of my remarks, much like Mr. Zed, I will be passing out copies of my submission.

First with respect to the PPAs. The PPAs specify the terms and conditions under which Genco, Colesonco and Nuclearco are to supply power to DISCO.

The electricity White Paper foresaw that the PPAs would be a transitional tool used to meet the electricity needs of DISCO's customers as competitive markets develop in New Brunswick. The PPAs, according to DISCO, were imposed on DISCO by government. DISCO has represented that it is legally obligated to make the payments under the PPAs.

DISCO has in this hearing expressed its intent to follow the terms and conditions of the PPAs. The specific terms and conditions of the PPAs and how DISCO applied those terms and conditions are crucial to the determination of whether DISCO's purchase power costs are just and reasonable and ultimately whether DISCO's rates are just and reasonable.

Witness Strunk has commented on contracts between affiliated company. He says in his report of June 14th 2007, and I quote, "Contracts between affiliated companies raise concerns for regulators. In a situation where a distribution utility such as DISCO buys power under a PPA from an affiliated generator, such as Genco, regulators are concerned that the purchasing utility's customers may be paying too much as a result of contractual terms that are overly preferential to the affiliate seller. In the US these concerns have led the Federal Energy Regulatory Commission, otherwise known as FERC, to establish specific regulatory standards for affiliate transactions and to scrutinize transactions between affiliates when there is doubt regarding compliance with those standards." End quote.

Further, Mr. Strunk goes on to comment, and again I will quote, "DISCO's forecast purchase power costs for the fiscal year 2007/2008 are in excess of $1 billion. The PPA costs represent approximately 80 percent of DISCO's total revenue requirement. Accordingly, any analysis of whether DISCO's rates are just and reasonable must concentrate on the cost of purchased power. It is standard regulatory practice to review the pass through of purchased power costs by electricity distribution companies in the context of an evaluation of the prudence of the utility's management decision making. Since pass through costs are an input to the regulated rates that must be approved by the regulatory authority, they are routinely subject to scrutiny in regulatory proceedings. Pass through costs must meet the regulatory standard of being prudently incurred in order for resulting rates to be just and reasonable." End quote.

And finally, Mr. Strunk concludes, quote, "DISCO has the responsibility to demonstrate that it has acted prudently with respect to decisions that impact its revenue requirement. An excessive cost that is imprudent cannot be part of a just and reasonable rate. The Board must find DISCO management prudent prior to concluding that DISCO's revenue requirement, and therefore DISCO's rates, charges and tolls, are just and reasonable."

Mr. Chairman, I submit that Mr. Strunk's evidence on this matter can be summarized in three points. Firstly, affiliate contracts are a matter of concern for regulators and must be a matter of particular concern for this regulator. Secondly, any demonstration of just and reasonable rates must focus on the costs that run through the purchase power agreements. And thirdly, DISCO has the burden to prove that the costs that make up the revenue requirement are prudently incurred and that DISCO's management acted in a prudent manner in all of the arrangements it made with its affiliates.

I would like to now turn to DISCO's conduct in managing the PPAs, and, Mr. Chairman, I submit it's difficult at best to characterize DISCO's management of the PPAs. Cavalier is one way of describing it. Indifference to the consequences of its actions on its ratepayers is another way.

DISCO's management must believe that the art of negotiating with affiliates, particularly with Genco, involves total capitulation with no benefits received for its ratepayers. How else can one describe the conduct that has unfolded before the Board in this rate case.

The President of DISCO says that the PPAs are irrelevant at the corporate level, that is, at the Holdco level. Surely there is no more telling comment about the status of DISCO than that. How can DISCO management be expected to conduct their affairs in a prudent way consistent with the terms of the PPAs and in the best interest of the ratepayers when the President insists that the PPAs are irrelevant?

If the reorganization of NB Power is to remain as part of government policy, and if the PPAs are to govern the relationships between the affiliates, then these PPAs must be subject to regulatory oversight. Time and time again in this hearing we have seen examples of preferential dealing where the failure of DISCO's management to act prudently and in the best interests of ratepayers has led to decisions, Belledune, hedging costs, settlement benefits, among others, that have resulted in material costs being imposed on DISCO's ratepayers, or where direct access to material benefits have been denied to these same ratepayers.

Simply put, this Board cannot trust DISCO's management to act in the best interest of its ratepayers. The Board must assume an oversight role to protect DISCO's ratepayers.

With respect to the PDVSA settlement, NB Power Holdco commenced a lawsuit in New Brunswick against BITOR and PDVSA and later proceeded with an arbitration case against these same parties. As I understand the evidence, the PDVSA settlement was based on the arbitration case in New York, and that the New Brunswick action was discontinued.

In the arbitration claim, Holdco claimed relief as follows. 1, specific performance of the contract, or, 2, damages for breach of contract in the amount of $2.2 billion.

In the PDVSA settlement Holdco received a damage aware of $110 million US and a new fuel agreement. As such, Holdco received damages and partial performance of the contract, the exact relief claimed in the arbitration case in New York.

The settlement value has been subject to a number of different estimates. The initial value proclaimed at a press conference by the President of DISCO was in the order of $338 million. Since then the value of the settlement has been subject to accounting adjustments to reflect errors in the calculation of the interest benefit. Regardless of what value is proclaimed, it is important to understand that NB Power gave up a significant benefit in order to secure this settlement. The benefit surrendered was the existing agreement with

BITOR to supply heavy fuel oil at Orimulsion prices to Dalhousie until the date of the expiration of the Dalhousie Fuel Supply Agreement. Part of the settlement was the cancellation of this supply agreement and its replacement with a new fuel supply contract under the settlement agreement. The value surrendered by giving up the Dalhousie supply contract before its expiration date I submit is significant.

While this will have no effect on DISCO's revenue requirement in this test year, it is part of the price, along with the $6 million in legal fees, that DISCO's ratepayers will have to pay in order to facilitate a settlement, the benefits of which it will only receive a part.

In a notice of motion filed with the Board on August 8th 2007, DISCO proposed that the settlement of the lawsuit should be handled by, firstly, the establishment of a deferral account to handle the amortization of the benefits of the fuel component in the settlement agreement, and, secondly, a reduction to the revenue requirement in the amount of $29.2 million.

DISCO also advised that the $46.7 million of the cash portion of the settlement would be treated as a recovery against the cost of the fuel delivery system. The Board considered this application of the $46.7 million to be appropriate, based on the testimony of the CFO of DISCO.

In Section 9.2 of the amendment number 2, sections 4.3.2, 4.3.3 and 4.3.4 of the vesting agreement, are deleted as of August 2nd 2007. The pre-amendment sections, particularly Section 4.3.4, dealt with the application of damages from the lawsuit against PDVSA, a lawsuit in which NB Power had been engaged in since February 2004, according to the actual amendment.

The pre-amendment section required DISCO to pay all costs associated with the lawsuit against PDVSA, and the evidence shows that DISCO did pay all costs associated with this lawsuit. In return, Genco and Holdco were to pay all damages they received from the lawsuit to DISCO. The amendment of these sections clearly deprives DISCO of these benefits, in particular, the sum of $46.7 million, which Holdco retained and applied to a debt with the province which had been written off since before October 1st 2004. It is interesting to note, Mr. Chairman, that Holdco only paid the taxes on this amount to the province and retained the remainder.

The pre-amendment sections were put in place on October 1st 2004. This date is clearly after the lawsuit, as defined in the actual amendment.

Section 4.3.4 of the vesting agreement is very clear in its intent, and this is acknowledged by Ms. MacFarlane at page 1303 of the transcript, lines 10 to 13, where Ms. MacFarlane states, and I will quote, "What it means is -- well the words are Genco shall pay DISCO all damages it receives in connection with the claim against Orimulsion. That is what the words say." End quote.

Now Ms. MacFarlane at page 1302 of the transcript, lines 11 to 15, states the following as to the reason an amendment to this section was necessary. "This is one of the sections where I made reference to something that was not anticipated at the time that the PPAs were struck, being the form of the Orimulsion settlement and where specific words do not align with the principles behind the PPAs." End quote.

Now if we were to look at the background to this, which I have already outlined, it is clear that the PPAs anticipated this lawsuit, it is clear what NB Holdco expected to receive as relief, that is, specific performance or damages, and it is clear that the settlement provided Holdco with damages of 110 million US and performance of the contract in terms of a new fuel supply agreement.

At page 1229 of the transcript, lines 11 to 14, Ms.

MacFarlane states as follows when asked if DISCO intends to follow the terms of the PPAs. "DISCO intends to follow the terms of the PPAs. If an unanticipated situation arises and the PPA has to be amended because it is not contemplated, then we will do that." End quote.

The evidence I submit does not disclose any unanticipated situations as it relates to this situation. In fact, the contrary is true. The PPA calls for this exact situation. It did not allow for the repayment of a debt which was already written off in 2004 and which in fact only the taxes on the 46.7 million were paid, with Holdco retaining the remainder.

This is a clear situation of preferential dealing among affiliate companies, an issue which Mr. Strunk warned that regulators must be concerned with. This amendment is clearly not a prudent decision as it relates to DISCO in that it deprives the ratepayers of the $46.7 million, without any tangible benefits flowing to the ratepayers.

As such, I submit that this application of the proceeds should be disallowed and the original intent and the principles of the PPAs restored. This will allow the money to benefit and flow to the ratepayers.

The purpose of this rate case application is for DISCO to establish the prudency of its rate requirement. It is not sufficient for the Applicant to merely list its expenses as prima facia proof of their prudency. The burden is on DISCO to demonstrate that any and all of the expenses, including the PPA expenses, are prudently incurred and should be passed on to the ratepayers. With respect to a number of those expenses, I contend that the utility has not met this burden of proof.

First I would like to deal with the rate of return for DISCO. DISCO has requested that the Board approve an interest coverage ratio of 1.25 times, with the prospect that at some point in time a retained earnings position of between 20 to 30 percent of total capitalization would be achieved. This request by DISCO is analogous to forcing ratepayers to make an equity investment in the utility, and then making these same ratepayers pay a rate of return of their own investment.

DISCO has made much in its evidence, as advanced by Ms. McShane, that DISCO should be treated like a privately owned utility. Witness Booth was clear in his evidence that this tactic on the part of the utility was inappropriate. He stated, and I quote, "If the province wants DISCO to be treated like a privately owned utility then I would expect to see all manner of changes. At a minimum I would expect to see Electric Finance refinance

DISCO's capital structure to inject common equity into the structure, DISCO to be awarded a fair rate of return, DISCO to be allowed a series of deferral accounts to mitigate its risks, DISCO to be treated as a stand alone entity, and finally, the Province to abstain from intervening in DISCO." End quote.

It is interesting to note that Dr. Booth believes it is necessary for the shareholder, not the ratepayer, to make an equity investment in DISCO if DISCO is to be viewed as the equivalent of a privately owned utility.

Because there is no common equity in DISCO's rate structure, because there is no assurance that the Lieutenant-Governor in Council will not exercise its options under Sections 37(3) and (4) of the Electricity Act to demand payments from DISCO in excess of the payment in lieu of taxes, and because there is no assurance that the Lieutenant-Governor in Council will not exercise its option to modify or reverse an order of this Board with respect to the charges, rates and tolls of DISCO, I request that the Board disallow the $9.8 million in net income for DISCO that is in the revenue requirement.

Now I just want to make a few comments on Mr. Morrison's argument yesterday before I leave this topic. Mr. Morrison referred to Dr. Booth's testimony in argument yesterday when speaking about interest coverage ratios.

I believe Mr. Morrison referred to Dr. Booth's testimony where he stated there is no reason to depart from the Board rulings in terms of the interest coverage ratios. What Mr. Morrison neglected to point out was that later in my examination I asked Dr. Booth the following question. Quote, "Dr. Booth, just so we are clear, what do you propose as retained earnings or interest coverage ratios for DISCO?" Dr. Booth's response was, I will quote, "I would recommend the Board continue with existing practice. I can see no reason for changes. An interest coverage ratio of one would essentially -- it just covers the ratio that is being charged on DISCO's operation is sufficient. There is a question of the build-up of retained earnings that has already occurred, but that is relatively low. I suggest that that also be charged at the borrowing cost of the Province because that equity is not equity in any substantive sense. It is simply payments made by the people of New Brunswick for electricity in excess of the cost of providing that service."

It is clear, Mr. Chairman, from the answer that Dr. Booth is of the opinion that the interest coverage ratio should be one. In fact this coverage ratio corresponds with what David Hay said in his testimony while being questioned by Ms. Desmond at pages 1064 and 1065, where she asked how DISCO is faring in achieving their objectives of behaving like a privately owned corporation. Mr. Hay responded as follows at page 1065, beginning at line 2. Well I think we are ding a good job and I agree with all those comments about what the objective was. And I think in many respects what we are trying to do is achieve the best of our worlds, and the best of our worlds is to have ourself financed through the government at debt rate and run ourselves like a private corporation in terms of -- and I don't mean by that extracting profits, blah, blah, blah. That sounds like an interest coverage ratio of one.

Later he states at page 1066, line 11, So I think throughout the entire corporation we are doing extremely well in achieving the objectives of the government without achieving the financial objectives, because we couldn't simply do it without having a debt for equity swap. This is one of the reasons, Mr. Chairman, Dr. Booth argues that an interest coverage ratio of one is proper for DISCO and it appears that President Hay agrees with him.

Technically, Mr. Chairman, this Board does not regulate Genco and Nuclearco. Nevertheless both of these entities have rates of return built into the PPA costs that are charged to DISCO. Because the PPA costs are a dollar-for-dollar pass-through by DISCO to its ratepayers, what we have here is analogous to forcing DISCO's ratepayers to make an equity investment in Genco and Nuclearco, and then making these same ratepayers pay a rate of return on their own investment so as to benefit NB Electric Finance.

Neither Genco nor Nuclearco has common equity in the capital structure. So their attempts to earn a rate of return are based on the same false assumption that pertains to DISCO. If it is not prudent to allow the pass through of DISCO's net income to DISCO's ratepayers, it is most certainly not prudent to allow Genco and Nuclearco to pass through their net income requirements by way of PPA costs to DISCO and ultimately to the ratepayers.

I request that the Board disallow the pass through to DISCO's ratepayers of the $23.4 million in net income for Genco and Nuclearco that is in the PPA costs that are charged to DISCO.

Mr. Chairman, with respect to economic dispatch, I raised the matter of economic dispatch very early in this proceeding. In PI IR-7, which is found at exhibit A-20, I defined economic dispatch as the allocation of demand to individual generating units on line to effect the most economical production of electricity.

The issue of economic dispatch arises out of the contracts that Genco holds with certain non-utility generators, otherwise known as the NUGs. These contracts are relevant to this hearing because the cost of the NUG contracts flow through to DISCO as a cost in the vesting agreement. The dispatch of Genco's own generating units is affected by the fact that the NUGs are modelled as take or pay contracts. That is, they are dispatched out of true economic dispatch order.

Witness Strunk in his evidence of November 5th 2007, at page 11, indicated that, and I will quote, "There has been a trend in the industry dating back over a decade in which purchasing utilities have moved away from signing must-take contracts with NUGs that can indeed be dispatched. Further, most utilities that had pre-existing NUG contracts with must-take delivery terms have renegotiated those contracts to remove the must-take provisions and reduce costs.

To the extent that the renegotiation of the contract terms to introduce dispatch flexibility can create net savings, it is prudent for the purchasing utility to pursue renegotiation opportunities, recognizing that in order to make renegotiation of the contract attractive to the NUG, a portion of the savings has to be shared with the NUG. It is imprudent for a purchasing utility to leave potential dispatch savings on the table if a renegotiation can be achieved.

There is no evidence, I submit, on the record that Genco has ever made any effort to renegotiate the NUG contracts to remove the must-take provisions. In point of fact, there is no reason for Genco to do so, since it has free reign to pass the cost on non-economic dispatch onto DISCO, with the full expectation that DISCO will recover these costs in its revenue requirement.

Witness Strunk has quantified the cost of non-economic dispatch with the largest of the NUG contracts, that is, Bayside. This was done in response to PI Disco IR-39, which is found in exhibit PI-4.

Using the PROMOD data provided by DISCO, he developed estimates of the generation costs of the units in Genco's system. From there, he built a model that replicates the dispatch of NB Power's plants.

And Mr. Strunk noted in his evidence of November 5th the following, and I will quote, "I then ran the stacking model two ways for the November 2005 to March 2006 period. The first way modelled Bayside as a dispatchable plant and the second way modeled Bayside as a must-run. The resulting difference in cost between the two model runs is the cost of the must-take provisions in the Bayside PPA, which as noted above is estimated to be on the order of $11 million per year." End quote.

Because Bayside represents non-economic dispatch, because Genco has provided no evidence that it has attempted to renegotiate the Bayside contract, because Genco passes these costs through to DISCO, and because DISCO has not demonstrated the prudency of these costs, I request that the Board disallow the pass through to DISCO's ratepayers of the $11.4 million in non-economic dispatch costs that are in the vesting agreement costs that are charged to DISCO.

In the alternative, DISCO should be required to file PROMOD runs that quantify the cost difference between modelling all NUGs as a must-run versus dispatchable. The cost difference should be removed from the revenue requirement for DISCO.

In the event that DISCO fails to file these PROMOD runs, the Board should make reference to the filings in the 2005 rate case, in which the costs on non-economic dispatch were calculated in an amount in excess of $25 million. This amount should be removed from DISCO's revenue requirement.

Now Mr. Chairman, I have earlier argues that the amendment concocted by the Applicant to arbitrarily remove $46.7 million in settlement benefits from Disco ratepayer is a clear situation of preferential dealing among affiliate companies.

The amendment is clearly not a prudent decision by DISCO's management. It is interesting to contrast the behaviour of the Applicant when contemplating the treatment of benefits and costs that are to be assigned to DISCO under the provisions of the PPAs.

Consider the following dialogue between Board counsel, Ms. Desmond and DISCO's Vice-President and CFO, Ms. MacFarlane, which is contained at page 2018, 2019 of the transcript.

Ms. Desmond, the question was, I had a couple of questions, Ms. MacFarlane, around the legal fees that were paid to resolve the PDVSA settlement. Can you confirm what the amount was paid by DISCO by way of legal fees? Ms. MacFarlane's answer, I don't have that with me, but I believe it's in the order of $6 million. The question, And the entire cost of the legal fees for the PDVSA settlement was paid by DISCO? The answer by Ms. MacFarlane, That's correct. Ms. Desmond asked, And why was is it entirely paid by DISCO? Ms. MacFarlane's answer,

The amount was entirely paid by DISCO because frankly that's what was outlined in the PPA.

Interesting, isn't it, Mr. Chairman that the virtues of the PPAs are never more apparent that when money can be extracted from DISCO.

Because this application of the proceeds was never contemplated by Section 4.3.4 of the vesting agreement, because the PPAs were designed in part in anticipation of this lawsuit and because the PPAs did not allow for the repayment of a debt, which was already written off in 2004, I request that the Board disallow the pass through to Holdco of the 46.7 million that forms part of the damages that were to accrue to DISCO and its ratepayers under the provisions of Section 4.3.4 of the vesting agreement.

I would like now to move with respect to the hedging costs, Mr. Chairman. Firms hedge to protect against extreme outcomes. In the case of NB Power, NB Power may hedge to protect against an increase in oil and natural gas prices or a decrease in the value of the Canadian dollar. Hedging the way NB Power does, it locks in fixed prices. While these fixed prices may protect against price increases, they also mean that NB Power cannot take advantage of the decline in the price of these commodities or strengthening in the Canadian dollar.

Mr. Strunk addressed the question of whether NB Power's hedging policy is necessary to protect DISCO's customers from fluctuations in commodity prices and foreign exchange rates. As stated in Mr. Strunk's report, the vesting agreement already contains an implicit hedge.

Mr. Strunk explained and I will quote, "Under the vesting agreement prices to DISCO's customers are stabilized through the fixing of the vesting energy price well in advance of the delivery period. The price is fixed on October 1 for the following fiscal year. The vesting agreement therefore provides a hedge for DISCO's customers without the need for additional hedges by Genco. And this is found at page 9 of Mr. Strunk's December 7th testimony or evidence."

Mr. Strunk also explained that the vesting agreement does not foresee the pass through of the hedge gains and losses to DISCO. DISCO is specifically undermining the terms of the vesting agreement by including hedge losses in its revenue requirement.

While Mr. Strunk recognized that it may be prudent for DISCO to enter into changes to the hedging provisions of the vesting agreement on a prospective basis, he emphasized that retroactive application of the changes to the vesting agreement is preferential to DISCO's affiliates with the excess cost being borne by DISCO's customers.

The evidence put forth in this proceeding overwhelmingly I submit supports a conclusion by the Board that the $48.9 million of Genco's financial hedging losses is not a reasonable and prudent expense to be borne by DISCO and is not reasonable to require the consumers of New Brunswick to pay for this.

I therefore recommend that the Board disallow the $48.9 million in hedged losses and reduce DISCO's revenue requirement in accordance with the schedule deemed appropriate by the Board.

I request that the Board disallow the pass through to DISCO's ratepayers of the 48.9 million in hedging costs that were assigned to DISCO in violation of schedule 6.2, clause 7 of the vesting agreement.

Now, Mr. Chairman, I want to turn to the cost allocation and rate design issues. And first I would like to deal with the issue of cost allocation. As the Applicant has pointed out on numerous occasions, the Board has ruled that it intends to accept the currently approved method for us in allocating costs for the 2007/2008. That ruling has significantly constrained the amount of information that is available within this proceeding with respect to rate design.

While I will get to my recommendations regarding hearing procedures at the end of this argument, I observe that these restrictions have not completely thwarted efforts to modify the Applicant's cost allocation study or CCAS.

On behalf of CME, Mr. Drazen proposes to modify the allocation of generation costs for large firm industrial customers. Dr. Sollows offers a wide variety of alternative cost allocation methods within the residential class. And Mr. Knecht presents a specific proposal in respect of the classification of distribution equipment.

To the extent that the Board is willing to consider any or all of these proposals, they can only be evaluated based on the evidence that is available in this proceeding.

From that perspective, Dr. Drazen -- or Mr. Drazen's recommendations regarding generation cost allocation must surely be rejected.

First, Mr. Drazen has not prepared a full cost allocation adjustment. His calculations are limited to the large industrial firm rate class. As such the impact of Mr. Drazen's proposal on residential, General Service, municipal and all other classes cannot be evaluated.

Secondly, Mr. Drazen's proposal is at best an educated guess as to what the implications of his proposed methodological change would be if he had the proper cost information. Under cross examination by Mr. Morrison, Mr. Drazen readily admitted that his figures did not represent actual NB Power cost data.

Third, the modifications to the CCAS methodology that are proposed by Mr. Drazen in this proceeding were in fact proposed by Dr. Rosenberg in the 2005 CARD proceeding. And they were rejected by the Board. No additional information is available in this proceeding. And in fact, quite a lot less information is available.

Fourth, as Mr. Larlee noted, if a generic proceeding for generation cost allocation were to be held today, the information available to the Board would be similar to that presented in the 2005 CARD proceeding. And it is likely that the Board would reach the same conclusion with respect to the Rosenberg/Drazen approach.

Turning briefly to Dr. Sollows' recommendations for the residential rate class, I submit that for Dr. Sollows' approach to have any merit for rate design, that his analysis should rely on the same cost allocation methodology within the residential class that is applied at the CCAS level for allocation among various rate classes.

Otherwise, Dr. Sollows' approach would necessarily not be consistent with cost causation.

Last I offer the following points in support of Mr. Knecht's proposal with respect to distribution plant cost classification. As Mr. Knecht explained, distribution costs for poles, conductors and transformers have both a demand-related component and a customer-related component. The demand component recognizes that the equipment with greater capacity costs more. The customer component recognizes that it costs more to serve many customers -- or many small customers than to serve a few larger customers.

Unfortunately, the method used in DISCO's CCAS does not represent a reasonable classification split between these two components of cost causation for the following reasons.

First, the existing methodology is one that was approved in the 1992 CARD proceeding. However, DISCO's expert, Mr. Larlee, was unable to offer any hard support for that methodology describing it as an iterative process.

Similarly, the CEA report refers to the methodology as being, quote "understood to be founded upon broad industry guidelines proposed by a cost of service expert prior to the 1992 rate case." As such, there is virtually no evidence to support the existing methodology.

Secondly, in the 2005 CARD proceeding, the Board directed DISCO to study this matter. In response, DISCO commissioned the CEA report, chapter 1, and its findings are on record in this proceeding. Moreover, DISCO has responded to all interrogatories in respect of CEA's analysis. As such the record has sufficient information by which the Board can evaluate the advantages of the different methods.

Thirdly, in the last proceeding Mr. Knecht prepared an analysis of distribution cost classifications based on the record in evidence in that proceeding. In this proceeding, he updated that analysis based on the findings in the CEA report. He reached the same conclusions in both cases.

The 1992 cost classification method overstates the customer-related component of distribution costs. In both proceedings, he offered very similar alternative approaches. Thus the record on evidence -- or record in evidence is sufficient to justify a change.

Finally, DISCO's assertion that the CEA report justifies continued use of the 1992 methodology is not credible. The CEA report concludes that no change is necessary because the impact is small. However, regardless of the size of the impact, the standard for the CCAS should be accuracy, not foolish historical consistency. Moreover, as Mr. Knecht has demonstrated, the choice of a distribution plant classification scheme can have a large impact on the cost signals for the monthly customer charge for residential customers. In light of Mr. Peacock's evidence regarding the impact of the customer charge on low income New Brunswickers, we submit that the implications are significant. For those reasons, Mr. Chairman, I recommend that Mr. Knecht's recommendations for the distribution cost classification in this proceeding be adopted. However, I also recognize that DISCO is developing a GIS database that may eventually update and improve the accuracy of its distribution plant analysis. We support that approach as well and submit that the Board should direct DISCO to update its analysis as soon as the data -- as the data permit. We recommend that Mr. Knecht's approach be used until such time as DISCO can present an updated analysis.

Mr. Chairman, I now turn to the issue of revenue allocation or sharing the rate increase. Only DISCO and Mr. Knecht have offered specific proposals for revenue allocation in this proceeding. Though Mr. Drazen argues that the large industrial firm customers should face an increase that is no more than average.

First let me turn to Mr. Drazen's suggestion. Mr. Drazen's first argument is that the cost allocation study is not accurate. For the reasons I have explained, Mr. Drazen's alternative cost allocation approach is not credible evidence in this proceeding. Mr. Drazen also argues that surplus interruptible customers are facing a large percentage increase in this proceeding and that this increase should not be compounded with an above average increase for firm service.

While Mr. Drazen is presumably correct about the magnitude of the interruptible rate increase, we disagree that it is particularly relevant for this problem. DISCO's surplus and interruptible customers pay an incremental cost rate and contribute very little to fixed plant cost in excess of that rate. When fuel costs are low, as they have been for many years prior to the recent past, these customers benefits from near firm service with very few interruptions at low incremental costs.

In taking that service, these customers must have recognized that there would come a time when fuel prices would rise. They readily accepted that risk in exchange for inexpensive service. In our view it is now disingenuous for those customers having benefited for many years from this approach to now use this argument to demand high cross subsidies for firm service from the other rate classes.

Turning back to DISCO's proposal, it is quite clear that DISCO has elevated the principle of gradualism to a high art form. The simple fact is that the General Service customers have been providing significant subsidies to other rate classes for a very long time and DISCO -- and before it, NB Power, have made little or no effort to ameliorate this situation.

DISCO's proposal in this proceeding is wholly inadequate, I submit. In fact despite having a revenue cost ratio of 119 percent at present rates, DISCO proposes to impose an increase on General Service II customers that makes zero progress towards cost-based rates.

Finally, turning to Mr. Knecht's recommendations, he proposes to assign a rate increase to large industrial customers that is 1.5 times the system average increase at 9.6 percent. This proposal will modestly increase the revenue cost ratio for large industrial firm service from 89.1 percent to 91.6 percent.

In effect, even under Mr. Knecht's proposal the large industrial firm rate class will still be well outside the Board's 95 percent to 105 percent range or reasonableness for revenue to cost ratios. It is also a rate increase for that class that is lower than that originally filed by DISCO in this proceeding.

With the extra revenue from the large industrial class, Mr. Knecht's proposes to impose a more modest increase for General Service customers, averaging 3.2 percent or about half the system average increase. He proposes a lower increase for General Service I customers, at 1.7 percent and a somewhat higher one for General Service II at 4.5 percent. Consistent with DISCO's goal of bringing those two rates together.

I submit that Mr. Knecht's proposes revenue allocation is superior to DISCO's in that it makes some material progress towards cost-based rates for the General Service customer classes while respecting the principles of gradualism.

Turning now, Mr. Chairman, to the issue of residential rates, I submit that the most important issue is the phase-out of the declining block rates. Under declining block rates, DISCO's charge per kilowatt hour, for kilowatt hour consumption in excess of 1300 kilowatt hours per month is $7.16 per kilowatt hour. Some 21 percent below the $9.04 per kilowatt hour charged for the first 1300 kilowatt hours per month.

There is simply no justification at all for this discount. And there are many reasons why it should be eliminated.

First there is no cost justification for the lower tail block rate. Consumption above the 1300 kilowatt-hour break point is often electric resistance heat load which is incurred during the peak season.

Thus serving this load contributes to DISCO's need for more capacity. And it may cause DISCO at least indirectly through Genco to incur higher variable fuel costs. As DISCO's CCAS shows, the revenue cost ratio for electric heat customers is under 94 percent at DISCO's proposed rates.

Secondly, eliminating the discounted tail block would encourage both conservation and where available fuel switching. Both options would likely result in environmental benefits as well as economic efficiencies.

Thirdly, the declining block tariff likely provides inequitable subsidized rates for wealthier residential customers with larger homes at the expense of lower income customers with smaller homes.

Fourthly, the elimination of the declining blocks in the tariffs will open the door for DISCO to pursue a more accurate rate design for residential customers, be it seasonal, other time of use or inclining block rates, as well as a reevaluation of the appropriate size of any tariff blocks as suggested by Dr. Sollows' analysis.

In this proceeding, Mr. Chairman, DISCO proposes to follow the approach ordered by the Board in the 2005 CARD decision, which represents a one-third phaseout of the tail block discount.

EGNB proposes that the declining block discount be eliminated in its entirety. Mr. Knecht generally supports DISCO's proposal but recognizes that it is modest progress at best and would surely be superior to the eventual results of the last set of proceedings.

We submit that the timing of the phaseout of the residential declining block tariff is a matter of judgement. DISCO's proposal certainly sets a floor for the minimum progress that can be made in one proceeding.

In our view, however, EGNB's proposal would be excessive. Eliminating the declining block entirely would require a 25.5 percent increase in the tail block charge. For the largest residential customer this would be a bill increase of nearly 25 percent, some four times the system average increase.

In our view, which is necessarily based on judgement in considering all of the facts adduced in this proceeding, if DISCO's proposal sets a lower bound for the amount of the phaseout, a reasonable upper bound would be phasing out one-half of the tail block discount.

We therefore recommend that the Board require DISCO to develop a residential tariff design that eliminates from one-third to one-half of the tail block rate discount in this proceeding.

What is perhaps more important in our view is to ensure that the progress towards achieving the goal of eliminating the declining block tariff continues to be made if DISCO does not appear before the Board for another rate proceeding for several years.

DISCO has indicated that it intends to phase out the declining block tariff by December 21st 2010. However, I submit that more rapid progress can be achieved even with DISCO's proposal as filed in this proceeding.

If DISCO can make progress of one-third in this proceeding for the 2007/2008 test year, then surely it can make another one-third progress in rates for 2008/2009 and eliminate the declining block tariff in 2009/2010.

We respectfully recommend therefore that the Board direct DISCO to phase out the residential declining block tariff in its rates for the 2009/2010 fiscal year.

The second issue in the residential tariff is the magnitude of the monthly customer service charge which is currently $19.16 per month for urban customers and $21 per month for rural and seasonal customers.

DISCO proposes that these charges remain at current levels. Mr. Knecht agrees with that proposal, though he recognizes that his cost allocation approach would justify a reduction in the customer charge and that doing so in this proceeding would not be unreasonable.

Mr. Peacock argues for an unspecified reduction in the customer charge, demonstrating that DISCO has historically imposed disproportionate rate increases on the service charge.

In my view this is also an issue of judgement. However as Mr. Knecht observes, any reduction in the customer charge will increase the impact of the rate design change on larger customers. Thus both decreasing the customer charge and phasing out the declining block charge will impose higher increases on large customers.

In our view, phasing out the declining block tariff is the more important of the two objectives. Moreover, rate stability and customer acceptance arguments support the continuation of the current service charges. Thus we do not endorse any reduction to customer service charges at this time.

Finally in the 2005 CARD proceeding the Board directed DISCO to study the issue of including farms and churches in the residential tariff. In response DISCO commissioned chapter 2 of the CEA report. Without dwelling on that result in detail, it is quite clear that CEA concluded both, that including extremely large farms without constraint in the residential class was very unusual policy, and that there are cost reasons for large farms to be subject to different rates than other residential customers.

Moreover, as Mr. Knecht noted in cross examination, it is not at all clear that the original policy which permitted farms to take residential service, intended to provide that benefit to extremely large customers who are over 50 times the size of the average residential customer.

In this proceeding DISCO proposes to do nothing about this issue. As a first step toward phasing out eligibility of the very large farm customers for residential service, Mr. Knecht proposes adding a third block charge for very large customers.

He also indicates that this approach would have the further benefit of making some additional progress toward elimination of the declining block structure.

We submit that there are two approaches that the Board could follow in this respect. It could defer the issue until the declining block tariff is phased out. Or it could follow Mr. Knecht's recommendation and take a step in the right direction now.

In our view, if DISCO's proposal for phasing out the declining block tariff by only one-third is adopted, we recommend that some additional progress be made by establishing the third block charge.

If, however, the Board determines that the tail block discount can be reduced by 50 percent in this proceeding, we recommend deferring the issue until full phaseout of the declining block charges is achieved.

With respect to General Service rate design, DISCO indicates that "There is no cost causation basis for General Service II customers to have a lower rate than other General Service customers."

We agree, Mr. Chairman, DISCO proposes to phase out the difference between General Service I and General Service II, and its proposal in this proceeding would be an additional step towards closing the gap.

Unfortunately DISCO and NB Power have allegedly been phasing out the difference between these two tariffs since at least 1992 with very little success.

The only specific alternative to DISCO's proposal was presented by Mr. Knecht. He conceptually agrees with DISCO's approach, both in terms of phasing out the difference between General Service I and General Service II and with respect to DISCO's tariff design.

However, because Mr. Knecht proposes lower overall rate increases for General Service I and General Service II classes, he concludes that some additional progress towards eliminating the difference between the two tariffs can be achieved.

Mr. Knecht's recommendations in this respect are unrebutted and unchallenged by cross examination. For that reason, if the Board can provide some relief to the General Service class in the form of lower overall rate increases, we submit that it would also be reasonable to adopt Mr. Knecht's recommendations for greater progress in General Service class rate design.

I would like to turn now to the issue of the possibility that interruptible and surplus customers may switch to firm service to the detriment of firm service customers, particularly during the Point Lepreau outage.

In the 2005 CARD proceeding the Board directed DISCO to study this issue. And DISCO commissioned chapter 5 of the CEA report. CEA very carefully concludes that if the revenues from firm service customers are greater than from the interruptible surplus customers, that firm service customers are not harmed.

While this is true, it is also pointless. Neither CEA nor DISCO have demonstrated that firm service rates will be higher than interruptible rates, particularly during the Lepreau outage.

Moreover, Mr. Knecht demonstrates that the average interruptible surplus rates will be higher than firm rates in the test year 2007/2008. And DISCO indicates that incremental costs, which are the basis for interruptible surplus rates, are likely to rise with the Lepreau outage. Thus there is a very strong likelihood that if interruptible surplus customers did switch to firm service, they may receive rates that are lower than the incremental costs of providing the service.

Now our recommendation in that respect is fairly simple. As long as DISCO's shareholder absorbs the cost of any switching, we have no objection. However we do request the Board warn DISCO that it will be on the hook for any losses associated with customers switching to firm service.

Moreover, as DISCO appears to believe that there is no problem in this respect, we recommend that the Board inform DISCO that the burden of demonstrating that there is no impact on firm service customers will lie with DISCO.

On this issue I note that my cross examination of Mr. Larlee brought out a couple of interesting facts of which at least I was unaware of.

First in a response dated September 14th 2007 DISCO indicated that it would experience a shortfall of some 201 megawatts in capacity during the Lepreau outage winter of 2008/2009.

However Mr. Larlee testified that DISCO has procured firm capacity from Hydro Quebec to meet this shortfall. We submit that to the extent firm capacity was secured in excess of that needed to serve firm customers, that these costs should be assigned to surplus interruptible customers at the appropriate time.

Second, Mr. Larlee indicates that, and I will quote, "While it is DISCO's intention to defer the costs around the Point Lepreau refurbishment, the details of that I don't believe have been established yet. That is the intention. The intention also is to include interruptible surplus as part of that deferral. And it would be collected out over time."

Since Mr. Larlee has suggested that some costs for providing replacement power to interruptible surplus customers will be part of the deferral, we conclude that DISCO must at least be considering selling power to these customers below incremental cost during some or all of the Lepreau outage.

We are of course somewhat concerned about the equity of any such approach. It appears that DISCO's philosophy is that interruptible surplus customers pay incremental costs only when fuel costs are low, but get subsidized when fuel costs are high.

However, as Mr. Larlee notes, this is not a test year issue. Nevertheless, we believe it would be reasonable for the Board to warn DISCO that any such deferral in cost should be eventually recovered from the specific customers who benefit from any subsidized pricing and not passed on to firm service customers.

Again, we respectfully request that the Board indicate that it will be DISCO's burden to demonstrate that firm service customers are not harmed by this proposal.

On this topic I have one last subject area in my argument regarding cost allocation and rate design. And that is the issue of procedure. And in particular I have two issues. First is the alleged need to have a generic proceeding in order to effect any changes to DISCO's CCAS.

Second is the advantages of regular public rate proceedings.

Regarding the first issue, Mr. Knecht identifies a number of reasons why regular review of both the cost allocation methodology and the underlying analysis is both reasonable and necessary, including the following.

First, DISCO's argument to limit cost allocation changes to generic proceedings is not consistent with practices in many other jurisdictions in Canada and the U.S. Secondly, Board decisions are based on the underlying economics in the proceedings in which the decision was made. Those economics may change. And parties should be allowed to investigate them. Third, generic proceedings focus on the big picture issue of generation cost allocation and can overlook other issues that may be better addressed in an ongoing fashion. Fourth, in this particular proceeding DISCO provided the results of Board-directed studies. And those issues are ripe for resolution at this time.

We therefore respectfully recommend that in future rate proceedings that the Board require DISCO to respond to interrogatories with respect to cost allocation issues, even if cost allocation methodology is not a subject to the proceeding.

Moreover, we also recommend that the Board be flexible in addressing at least some of the cost allocation methodology issues within the context of regular rate proceedings.

This brings me to my second procedural issue, namely the advantage of regular rate proceedings. We of course recognize that section 99(1) of the Electricity Act allows DISCO to impose rate increases without the need for a hearing before this Board, as long as the increases are not more than the greater of 3 percent or the percentage change in the average consumer price index.

Unfortunately in our view this provision may give DISCO too much flexibility by which it can avoid making any real progress on the revenue allocation and rate design objectives.

We observed that over the past 15 years without regulation DISCO has made virtually no progress towards phasing out the residential declining block tariff. It has made very little progress in equalizing General Service I and General Service II rates. And it has made very little progress in reducing the subsidies provided by the General Service customers.

In short, Mr. Chairman, we submit that DISCO is a utility that could benefit from fairly regular public review, less it slip back into its historical bad behaviour.

As Mr. Knecht indicated, DISCO is not a particularly good candidate for this form of performance-based regulation.

I therefore respectfully suggest that the Board advise the government that regular rate proceedings for DISCO would benefit both the ratepayers and the utility.

Now Mr. Chairman, at this point in time, I have prepared a document based on the evidence and intend to use it as part of my final argument.

And I would ask Ms. O'Donnell, if she is still in the room and hasn't fallen asleep, to pass that out.

Mr. Chairman, I am going to be requesting orders and rulings for the Board to consider. And in relation to its jurisdiction and to the power purchase agreements, I request the following orders from the Board.

(1) that the Board declare its jurisdiction over all contracts to which DISCO is a party, including without limitation Genco vesting agreement, the Nuclear generation agreement and the Coleson Cove tolling agreement, which are collectively known as the power purchase agreements or the PPAs.

(2) pursuant to its jurisdiction over the PPAs, the Board order DISCO as follows: (a) that DISCO submit all amendments to the PPAs together with a detailed explanation of each amendment and an assessment of the financial impact on DISCO to the Board for its approval; (b) that DISCO submit any and all decisions, changes or interpretations of the PPAs agreed to by the operating committees or directed by Electric Finance Corporation together with a detailed explanation of the decision, change or interpretation and an assessment of the financial impact on DISCO to the Board for its approval; (c) that DISCO be ordered to file with the Board on a monthly basis detailed cost data underlying the capacity and energy cost charges under the PPAs. This data should be accompanied by the evidence of the process DISCO followed to verify the reasonableness of the amounts charged; (d) that DISCO create and establish a deferral account and debit or credit the account with the balance of the third party gross margin adjustments as per section 6.4 of the vesting agreement; (e) that DISCO create and establish a deferral account and debit or credit the account with the balance of the hydro flow adjustments, which is in accordance with section 6.12 of the vesting agreement, and determined in each fiscal year; (e) that

the amount of the hydro flow adjustment for fiscal year 2007/2008 be established in a manner consistent with fiscal year ending March 31st 2006; (f) that the Board manage each of the deferral accounts in the public interest including without limitation (1) amortization of the current balances of the account over the succeeding three years; (2) in the event that either of the deferral accounts should have a credit balance, directing the establishment of a rate increase to establish the balance of the account; and (3) such further directions as the Board may determine to be in the public interest.

With respect, Mr. Chairman, to DISCO's revenue requirements, I request the following rulings from the Board.

(1) that the revenue requirement for DISCO for the fiscal year 2007/2008 be reduced by $44.6 million on the following basis; (a) by removal of $9.8 million in net income for DISCO; (b) by removal of $23.4 million in net income for Genco and Nuclearco, being an amount above generation cost, which otherwise would be passed onto DISCO's ratepayers through the PPA charges; and (c) by removal of $11.4 million in costs associated with noneconomic dispatch of NUG generation.

Secondly, Mr. Chairman, I request that the revenue requirement be reduced by $48.9 million or an amortized amount to be determined by the Board, this being an amount associated with the attempt by Genco to charge DISCO on a retroactive basis with hedging costs in violation of 6.2 of the vesting agreement.

(3) that the revenue requirement be reduced by $46.7 million or an amortized amount to be determined by the Board, this being an amount associated with the attempt by Holdco to deprive DISCO's ratepayers of a portion of the damages of the PDVSA settlement, in violation of section 4.3.4 of the vesting agreement.

(4) that reductions in the revenue requirement identified in numbers (1) to (3) above be reflected in an across-the-board reduction in proposed rate increases to all customer classes.

(5) that in the event that DISCO is not prepared to provide written assurances that it will not exercise the option to impose a 3 percent increase on rates under section 99 of the Electricity Act within fiscal year 2007/2008 that the Board further reduce the proposed rate increases to each customer class by the arithmetic average of the rate increase by customer class that the utility implemented under section 98 since January 1, 1994.

In support of my request for Board rulings with respect to the reductions in DISCO's revenue requirement, I have attached the spreadsheet that gives effect to both the amounts requested and the possible alternative amortization periods for both the PDVSA settlement and the hedging costs.

Mr. Chairman, with respect to cost allocation and rate design, I request the following rulings from the Board. (1) that the distribution cost classification recommended by witness Knecht be adopted; (2) that a rate increase to large industrial customers, that is 1.5 times system average, be implemented in this proceeding; (3) that a rate increase of 1.7 percent for General Service I and 4.5 percent for General Service II customers be implemented in this proceeding; (4) that DISCO be required to develop a residential tariff design that eliminates from one-third to one-half the tail block discount in this proceeding; (5) that DISCO phase out the residential declining block tariff in its rates for the 2009/2010 fiscal year; (6) that in the event that DISCO's proposal for phasing out the residential declining block tariff by only one-third is adopted, that a third block charge should be implemented for the very large farm customers; (7) that DISCO be required to file with the Board a report indicating the progress the Applicant will make in the next three years in General Service class rate design; (8) that DISCO be required to demonstrate that there is no impact on firm service customers for any losses associated with interruptible customers switching to firm service during the Lepreau outage; (9) that in future rate proceedings DISCO be required to respond to interrogatories with respect to cost allocation issues, even if cost allocation methodology is not a subject of that proceeding.

Mr. Chairman, I would like to conclude my report with a presentation on what I believe the state of the electricity market is in New Brunswick.

New Brunswick Power has for several decades been a key player in the history and development of New Brunswick. It was formed by the Provincial Legislature in the 1920s and ever since has assumed a leading role as a crown corporation assisting in the development and growth of the economy of this province.

But it is now a mature player in a mature industry. Mature industries are characterized by demand that is saturated and slow-growing, if not declining, and by eroding margins and returns.

The classic mature industry tends to grow at a slower pace in the economy in which it operates. Companies like

NB Power, which operate in a mature industry, require management that is skilled in short and long-term planning and requires oversight to ensure that such planning takes place.

Because NB Power is a monopoly provider of the electricity services, a regulatory authority must exercise this oversight.

Under section 127(1) of the Electricity Act, the Board is required to monitor the electricity sector and may report to the Minister on the state of the electricity sector, including the efficiency, fairness, transparency and competitiveness of the markets in the electricity sector.

As Public Intervenor, Mr. Chairman, I request the Board to report to the Minister on three key issues related to the electricity market in New Brunswick.

These three issues are as follows: (1) the current monopoly situation that exists in this market for both generation and distribution services; (2) the failure of the PPAs to properly regulate the relationship between affiliate companies; and (3) the need for significant changes to the Electricity Act to enhance the Board's ability to perform its oversight role with respect to NB Power.

Dealing with the first issue, monopoly in generation and distribution, in order for there to be competitive markets, Mr. Chairman, four conditions must be present. First there must be no barriers to entry or exit. Second there must be a sufficient number of buyers and sellers so that the actions of one party will have no impact on the other parties. Third buyers and sellers must act independently. And fourth there must be sufficient information available so that buyers and sellers know the prices set by all firms in the marketplace.

None of these conditions exist in either the generation of distribution marketplace in New Brunswick. Quite the contrary. Genco occupies a monopoly position that will exclude merchant generators from entering the market for decades.

And DISCO is a captive purchaser of Genco's generation. In turn DISCO is the sole provider in the province. And unless there are legislative changes there is no possibility of competition at the distribution level in New Brunswick.

The original intent of the White Paper and the subsequent analysis of the requirements for competitive markets may have been a laudable effort. But as always the devil is in the details.

It is hard to escape the conclusion that the final result, the Electricity Act, protects NB Power from competition at both generation and distribution level, while at the same time facilitating the ability to transfer revenues from DISCO to the other unregulated affiliates in a manner calculated to avoid the scrutiny of the Board.

I recommend, Mr. Chairman, that the Board make a representation to government that clearly outlines the inability of competitors to penetrate this market at either the generation or distribution level.

I further recommend that the Board make it unequivocally clear that there is no possibility of competition at either level for the foreseeable future.

What this jurisdiction has had and continues to have is the monopoly provisions of the electricity services.

With respect, Mr. Chairman, to the failure of the PPAs, I submit the PPAs have come under considerable scrutiny in this proceeding. They have been advanced by the Applicant as either imposed by government and two, consisting of terms that are the visible manifestation of some underlying principles that only utility management understands.

When the Vice-president and CFO of DISCO embarks on a surreal discourse on the distinction between the terms and the principles, it is time to acknowledge that truly the emperor has no clothes.

It is patently obvious that NB Power, as an integrated utility, was indirectly involved in shaping both the structure and the content of the PPAs. Furthermore these PPAs are between affiliate companies.

In other words, representatives from an integrated monopoly were heavily involved in creating the contractual relationships between potential affiliates that were to be spun off from the integrated utility.

What is the concern that we should have here? Quite simply, Mr. Chairman, preferential dealing. The potential for preferential dealing exists at three levels. First, DISCO is unable to purchase power from any other wholesaler other than DISCO -- or sorry, Genco. (2) the PPAs are affiliate contracts that require the pass-through of the associated costs by DISCO on a dollar for dollar basis. And (3) the PPAs are unlike contracts that are found in restructured markets. They leave important pricing decisions to be agreed to by buyer and seller. The vesting agreement relies on the use of an Operating Committee that has considerable discretion and judgment, particularly over issues that may impose a financial impact on DISCO's ratepayers.

It is this discretion, Mr. Chairman, and judgement that requires the Board to exercise its regulatory oversight. The record in this proceeding will not show a single decision at either the Operating Committee or senior management level that favored DISCO and its ratepayers. DISCO has been saddled with the Belledune boiler refit cost. DISCO has been saddled with the hedging costs in violation of the terms of the vesting agreement. DISCO has been deprived to some of the damages associated with the PDVSA settlement in violation of the terms of the vesting agreement.

I therefore recommend that the Board make a representation to Government that the PPAs are unsuitable as contracts for a restructured market. Rather they are contracts between affiliates that contain the potential for preferential dealing to the detriment of DISCO's ratepayers.

Accordingly, the Board should advise the Applicant of its intent to regulate the PPAs to protect the interests of all ratepayers

The third issue, Mr. Chairman, deals with changes to the Electricity Act. The Electricity Act was passed in 2003 in anticipation of the reorganization of the integrated NB Power into a series of affiliated companies. Presumably, the intent of the legislation was to facilitate the transition to a competitive market for electricity in New Brunswick.

Currently the Government is considering changes to this Act. Indeed, some amendments in the form of Bill 19 are currently before the Legislature. However, there are more significant changes that should be made to this legislation.

NB Power or whatever entity ends up being regulated by the Board should be declared a public utility. With this declaration the regulator can exercise its general supervisory powers and as well can enforce its orders on the utility.

Section 99 of the Electricity Act, Mr. Chairman, I submit should be repealed. It was not and is not appropriate to give NB Power the ability to avoid regulatory scrutiny by providing it with the right to raise rates by 3 percent without an application to this Board.

This provision in the legislation is not price cap regulation. There is no incentive for the utility to be efficient. There is only an inducement to automatically raise rates every year and to borrow to cover deficits.

The unfortunate legacy of this section of the Act is cumulative deficits exceeding $300 million.

Mr. Chairman, I recommend that the Board make a representation to the Government that the regulated entity be declared a public utility under the Electricity Act for regulatory purposes. I further request the Board to recommend to Government that section 99 of the Act be repealed.

Mr. Chairman and Board Members, it is with the utmost respect as Public Intervenor that I make these submissions to you today.

And on a closing note I guess I would want to take this opportunity to thank the Board and you, Mr. Chairman and Mr. Morrison and Mr. Keyes for their assistance throughout this. And I wish everyone here happy holidays. Thank you.

At this point too, Mr. Chairman, I would ask Ms. O'Donnell to hand out the -- she has made -- we have copies for everybody of my closing remarks.

CHAIRMAN: Thank you, Mr. Theriault. Questions from the Board?

Mr. Johnston?

VICE CHAIRMAN: Mr. Theriault, there is only one topic that I want to discuss. And I want to try and lead into it slowly. It is an argument that has been advanced on a number of days of hearings and during motions. But I think it is probably necessary to try and put it to you in a direct way.

And it deals with whether there are any limitations on the Board in dealing with the PDVSA settlement issue, since it is nonforecast revenue that came in during the test year.

These are my understandings of arguments that I think have been advanced at various times by the Applicant. And I hope I'm getting them right.

If I understand correctly, the $46 million for the fuel delivery system was an expenditure which was not forecast during that year to be written off, and as a result was never charged to the ratepayers in that year or in any other year.

And if I understand correctly from the motion when we were setting up the deferral account, the position that was advanced at that time -- I hope I'm getting this right -- was that since this was a nonforecast revenue, that is the PDVSA settlement, that there was not an obligation upon DISCO to deal with it and bring it into the revenue in any manner for the test year, but that they chose to do so.

That is the argument, as I understand it.

That being the case, are there limitations on the Board in dealing with nonforecast revenues, given that ratemaking, as is often asserted by the Applicant, is a prospective exercise?

I have tried to outline that as best I can without going into it in too much detail, Mr. Theriault. Do you know where I'm coming from here?

MR. THERIAULT: I think so.

VICE CHAIRMAN: Well, if you could just comment on what I have said, I guess I will leave it at that.

MR. THERIAULT: Mr. Vice Chairman, I think -- first of all, I don't think there is, from my recollection of the Act, any legislative restriction on the Board in using these funds in this test year.

Secondly, these funds came in in this test year and have been applied by DISCO's own, through the in-kind settlement, in this test year.

The third requirement is -- if you look at the vesting agreement, the section 4.3.4, which was the provision in effect prior to the so-called amendments, did not make reference to when it would come in. It just says that DISCO will receive the damages pursuant to that.

So they received it in this test year. So I see no reason and no restriction on why it should be applied -- or should not be applied to this particular test year.

VICE CHAIRMAN: Thank you.

CHAIRMAN: Thank you for your presentation, Mr. Theriault. It is now 25 after 12:00. We will take a break until 1:30 at which time we will deal with rebuttal arguments.

(Recess - 12:25 p.m. - 1:30 p.m.)

CHAIRMAN: Well the front of the dias here seems to have changed somewhat over the lunch break. Santa Claus isn't sitting up here.

Well I guess we are down to rebuttal argument. So I will start with Mr. Theriault. Anything further you wish to add by way of rebuttal?

MR. THERIAULT: Very quickly, Mr. Chairman. With respect to the 50 percent split of the $46.7 million that was mentioned by the Municipals this morning, I would just like to add that that reference to a 50 percent split is not supported I would suggest by the evidence, which is the very reason Mr. Zed uses to propose this approach. The evidence of DISCO on the cost of the refurbishment I would suggest is muddied at best and cannot support the Municipal's position, nor even the position suggested by CME yesterday. That's all. Thank you.

CHAIRMAN: Thank you, Mr. Theriault. Is Dr. Sollows here? Mr. Zed?

MR. ZED: I will forego rebutting the rebuttal.

CHAIRMAN: Thank you. Mr. Peacock?

MR. PEACOCK: Thank you, Mr. Chair. In a bout of Christmas spirit I pledged to the Applicant's counsel yesterday that I would not have rebuttal.

CHAIRMAN: Mr. Wolfe?

MR. WOLFE: I will be very brief, Mr. Chairman. I initially thought I wouldn't be talking again, but after the Municipals this morning I just couldn't resist. When they were talking about interruptible power, and when they talk about the zero cost hydro power, I believe that Mr. Kennedy was talking about a hypothetical issue at the time, and as somebody that uses surplus power to a very large extent, I can assure there has never been any at any time we have had zero cost hydro power.

The other thing I would like to say is that interruptions are very rare, but many, many times during the year we will self-interrupt ourselves because the price of power is so high, rather than wait for the power commission to interrupt us.

The other comment I would like to make is on Mr. Sollows' presentation. He suggested that it might be a good idea to have a committee that could get together and discuss some of these issues before they come to the Board. For eight years now there has been a pipeline -- natural gas pipeline in New Brunswick, and it's regulated by the NEB, and they have regular meetings with all their shippers and themselves, and I don't believe in eight years we have ever gone to NEB for a rate increase, even though the rate changes every year.

That's all I have, Mr. Chairman. Thank you.

CHAIRMAN: Thank you, Mr. Wolfe. Mr. MacDougall?

MR. MACDOUGALL: Thank you, Mr. Chair, Board members. Good afternoon. I have some rebuttal comments with respect to some issues raised by Mr. Morrison yesterday and a little bit with respect to some comments raised by Mr. Zed today and by the Public Intervenor today.

Starting with DISCO, Mr. Morrison argued yesterday that the 2005 CARD ruling that says the declining block must be removed by December 2010 should stand as determinative of this issue because it was decided in a generic hearing when parties specifically addressed this issue. He noted that although the Board subsequently changed their position on this matter in the 2006 rate case decision, this decision was reversed by an OIC from government.

Mr. Chair, Board members, EGNB submits that this position is both surprising and incorrect. It is surprising in that it was DISCO who applied to this Board earlier this year to extend the deadline of December 2010 to December 2011. And they did this by way of a motion with no new evidence, and I think in part, if my recollection is correct, they were arguing delay was required for the very reason that the OIC did not allow for the first step to reduce the declining block. Now they say all the necessary evidence was previously before the Board in 2005. This inconsistency in their position from earlier this year and today and is striking in our respectful submission.

In your decision on the motion of May 31, 2007, at page 11, you however ruled -- and I would just like to read from your ruling -- the Board expects that the residential declining block will be a topic of considerable discussion at the public hearing to review the rates for 2007/2008. The Board therefore does not consider it appropriate to vary the order at this time. You made it very clear that your view of this was going to be an item for considerable discussion at this hearing.

Mr. Morrison's position is incorrect in our respectful submission in that revisions to rates is exactly what this

Board is expected to consider in revenue requirement rate cases. As the Board ruled in its June 19, 2006, rate case decision -- and I referred to this yesterday -- at pages 51 and 52, while the Board reaffirms that DISCO should not move to a flat rate immediately its further and more detailed examination of evidence has led it to conclude that a more rapid move towards a flat rate is appropriate at this time. The Board as it was then constituted specifically noted that it had done a further and more detailed examination of the evidence and its finding was that a more rapid move towards a flat rate was appropriate.

The same parties were before the Board in that rate case as in the 2005 rate case hearing in the 2005 CARD portion of the hearing, and they are before you again today.

It is exactly in rate cases where you have the authority to make these type of findings.

Section 101(4)(c) of the Electricity Act, which I referred you to yesterday, specifically states that the Board may when considering an application by DISCO take into consideration among other things rate design matters.

Section 101 is the section of the Act which relates to DISCO's applications for approval of changes in its rates and charges. To suggest that this issue is not right for further decision of the Board at this time, with the significant amount of evidence before the Board on this issue, is we suggest simply incorrect.

Turning now to some comments by Mr. Zed from this morning. Mr. Zed indicated that with respect to a potential CARD ruling one should only take a look at cost allocation issues if there had been changed circumstances. Mr. Chair, Board members, EGNB respectfully submits that it is important in looking at this issue to look at the wording of what the Board said in its 2005 CARD ruling. And some of this was referenced yesterday by the representative of the CME. I would like to refer to the December 21, 2005, CARD ruling at page 22, and I will read the Board's comments at that point. The absence of a competitive market for energy and capacity means that a careful analysis of the actual costs of generation should occur to best establish fair and equitable rates. However, no detailed cost information on the actual generating facilities was provided, and the Board does not have the authority to order it to be provided. This places the Board in a very difficult position. It does not have all of the info that clearly exists that would normally be available to assist in setting rates. The

Board will, however, reluctantly fulfil its obligation to set rates.

They then said they would approve a methodology that they felt could provide a reasonable approximation of actual costs to be used until either a competitive market develops or detailed cost information is forthcoming from the NB Power group of companies.

Now, Mr. Chair, Board members, EGNB's methodology that was put forward in that rate case was mentioned by the Board at page 23 in their decision, and the Board again went on to say -- they weren't accepting the EGNB methodology because it was concerned with the lack of current and comprehensive cost info that was available to support this methodology. The concern wasn't with the evidence on the methodology or its potential appropriateness, but that there wasn't enough information to allow the Board to make a full determination on its appropriateness.

Mr. Drazen has raised similar concerns to those of Dr. Rosenberg in the last rate case, and again I note that Dr. Rosenberg's evidence although not before you in this case has been referred to a couple of times again today.

Mr. Knecht has raised concerns with respect to distribution cost allocation and Dr. Sollows has raised concerns with residential class cost allocation issues.

So if we now go to Section 104(4)(b) of the Electricity Act and again I referred the Board to this yesterday. Here it says the Board may when considering an application under this section take into consideration proposed allocation of costs among customer classes.

So the Board is entitled to look not only at rate design matters, but also at the proposed allocation of costs among customer classes. This, of course, by necessity must include the methodology by which the allocation is developed as this is the driver of the actual cost allocations.

And these items are matters that the Board may take into account when they are determining under Section 101(5)(a) as to whether or not the rates being put forward are just and reasonable.

In EGNB's submission the Board can certainly under Section 130 of the Act, which deals with terms in the public interest in your Orders, which we referred to you yesterday, require DISCO as part of the Board order for our 2008 CARD hearing, which we suggested yesterday would be appropriate for you to put forward, to provide sufficient info or information for the Board to be able to consider a proper allocation of costs among customer classes pursuant to Section 101(4) so that you would have that information prior to DISCO's next rate application. Absent this information, you will be in the same difficult position as your predecessors in trying to fully carry out your obligations pursuant to the Act to consider proposed allocation of costs among customer classes.

Mr. Chair, Board Members, briefly with respect to some of the comments from the Public Intervenor. Two issues I want to deal with. The first ties back to the points we were just making. I believe the Public Intervenor has also suggested that there has been -- there is a dearth of information with respect to particularly generation fixed costs and a dearth of information to fully do a proper allocation of costs among customer classes. And then he goes on to suggest that the changes to be made by -- or proposed to be made by the CME, for example, should not occur. But he then proposes that Mr. Knecht's revisions to the distribution cost classification can be made.

It's EGNB's position, as we mentioned yesterday that these matters should be part of an overall rate design and cost allocation proceeding for 2008. And you can't say that there is not enough information to make certain changes, but enough information to make other changes. As the Concentric report stated, and as Mr. Larlee confirmed, these are matters that are often inter-related and if there isn't sufficient information to properly deal with cost allocation m, it is incumbent on the Board to do what it can -- its Orders to attempt to get that information in our respectful submission.

Finally with respect to the Public Intervenor, in talking about the declining block and what he felt would be a correct approach -- and I have a copy, I wanted to make sure my notes from this morning were correct. So I have a copy of the written argument that he handed out. And at page 16, he refers to eliminating the declining block would require a 25.5 percent increase in the tail block charge. And that is correct. And that is what's set out in -- I think it's the response to NBEUB 84. However, he goes on to say for the largest residential customers, this would be an increase of nearly 25 percent, some four times the system average increase. That Mr. Chair and Board Members is simply incorrect. That is not in the evidence. There is no bill increase of nearly 25 percent. The 25 percent refers to the increase in the declining block. But the declining block is just a portion of the overall charge. It doesn't even refer to the first 1300 kilowatt hours. And the bill increase that he talks about is 25 percent, which isn't in the evidence, is not four times the system average increase, because I think what he is referring to here is the 6.4 percent, but that isn't a bill impact. That's the actual revenue rate impact. So there seems to be a real comparison of apples and oranges here and the 25 percent is somewhat misleading in our respectful submission.

Dealing with the information we actually do have, we would just encourage the Board again to look at DISCO's response to EGNB IR-1 on October 17 where the bill impacts are clearly laid out and which we dealt with significantly yesterday. That chart will show that there is a significant benefit for the majority, the vase majority customers in eliminating the declining block at this time.

The biggest impact is on large farms or the largest customers who could be dealt with in the manner that was raised by the Vice-Chair yesterday on questions with myself. We have to be very careful about allowing continuing benefit to a very few customers to be to the detriment of the vase majority of the residential customers. If in fact Mr. Theriault's revenue requirement reductions come into play, at which my quick math suggests are very, very significant, in fact there would be a substantially reduced revenue requirement, which would give the Board even greater flexibility in this regard.

Mr. Theriault's comments seem to assume no customer response with respect to those customers who would see a price signal. And again we just remind the Board that the failure to eliminate the declining block may hamper or limit the ability for this Board to in a timely fashion, and as we suggested in 2008, look at other rate forms that may be appropriate going forward such as seasonal or time of use rates.

Those are all of my reply comments. And again like my colleagues, I would like to thank everybody for their participation and their assistance in this matter and wish Happy Holidays to the Board and Staff. Thank you very much.

CHAIRMAN: Thank you, Mr. MacDougall. Mr. Kidd?

MR. KIDD: Good afternoon, Mr. Chair, members of the Board.

This going towards the end, I really like it. Next time I am going to ask David to request that we be the New Brunswick Conservation Council rather than Conservation Council of New Brunswick. Just like the order of where we are at here.

Anyway, I have had an opportunity to give some thought to Mr. Morrison's arguments or argument regarding the jurisdictional or oversight powers of this Board, and the impact -- or his arguments and its impact on the order regarding demand side management that the Conservation Council has asked this Board to make. And should the Board determine that the Electricity Act does not give it general oversight powers over DISCO, I would submit still -- or I would submit that the subject -- that subject to a few modifications the Conservation Council's requested order can still be given effect. And I base my position on Section 38(b) of the Energy and Utilities Board Act which, to paraphrase, provides that the Board in conducting its activities may request that anyone prepare studies relevant and incidental to the matter over which the Board is exercising jurisdiction. I would submit that demand side management and its potential to lower DISCO's revenue requirements is certainly relevant to the work of this Board.

The changes that could be made to the Conservation Council's requested order are simply -- at the beginning there was a phrase that says the Board shall take jurisdiction over the capacity planning process of DISCO, and I would take out the words, jurisdiction over, and substitute, take an active interest in the capacity planning process of DISCO, and also if you decide that you do not have the oversight powers that the part A, a DSM hearing shall commence on October 13th, 2008, could be removed, but the remainder of the requested order could still be given effect as it is all just dealing with a study or asking for a study, and the timing of when that study would be concluded.

I just wish to clarify that in part B they ask for a technical conference process. That is simply part of the study. It's not something outside of the study. It just helps to complete the study basically.

Again this study, if it's determined that you do not have this general oversight power but a study is required, it can either be ongoing issue or it could be, as Mr. MacDougall just suggested regarding a CCAS methodology -- it could be in preparation for the next rate hearing, whenever that may come. Again the timeliness would just guarantee that the DSM study will be ready in time for that hearing.

Finally, it has come to my attention that in my argument regarding DISCO's responsibility under the Electricity Act to provide energy efficiency programs to its ratepayers, in my argument I did not give proper and due consideration to the French versions of various pieces of legislation I discussed, for which I apologize. My French is horrendous.

More specifically in French, Section 101(4)(e) of the Electricity Act makes explicit reference to energy efficiency programs and finally, for the record, Section 101(4)(e) in French reads, and I apologize again in advance for my poor French -- 101(4) La Commission peut, lorsq'elle prend en considération une demand en vertu du présent article, tenir compte de ce qui suit: (e) des programmes d'efficacité énergétique institués ou planifiés par la Corporation d distribution.

Those are all my rebuttal comments for this afternoon. I would like to thank the Board again and wish everyone here a peaceful and restful holiday season.

CHAIRMAN: Thank you, Mr. Kidd. Thank you. Mr. Lawson?

MR. LAWSON: Thank you, Mr. Chair. Just a few brief comments. One with respect to the interruptible surplus power issue, Utilities Municipal addressed the need for conditions with respect to the -- going from interruptible to firm and vice versa. I think you will find that that already exists. I know that it was alluded to in the last hearings a couple of years ago and there is a contractual provision for notice requirements going out and I think going back in as well.

Similarly, with respect to the issue of Point Lepreau and the interruptible, the firm issue, I would submit that that is not an issue for this test year. I can't believe

I am quoting that particular comment from the Applicant, but I believe it is correct to say that it is not an issue for this test year.

On the issue of the PDVSA settlement, the 50/50 Canadian compromise approach by Utilities Municipal, I guess I would say it only has the virtue of splitting the baby in half. I don't think it's the right or fair or well-founded way to approach the divying up of those monies.

On the question that Vice-Chair Johnston addressed on this concept of projections as opposed to real, I guess my only comment and it's just not specifically with respect to that, but more broadly, the legislation I believe is in contemplation that normally a rate application would be dealt with fairly early on in a year and as a result you would be having to deal with projections. But the advantage, I won't describe the disadvantages, but the advantages of having one so late in the fiscal yes it that you can now -- ultimately you have to put the projections to the test. What better way to test the projections than the reality. And so we have the reality and we know the reality is different than the projections they put forth, partly because of the PDVSA settlement. And I would submit that in itself would allow the adjustment of the projections because the reality tells us those part of the projections can't be accepted, because there is this new money if you will. And I can only assume that would be at least part of the reason why the Applicant would have put forth the funds to be considered for this -- part of the funds to be considered for this test year.

With respect to the issue of the CARD matter, firstly I would comment I don't believe I heard any of the parties describe the CARD decision from 2005 as being accurate. Many have -- not many, a few, I am sorry, have said it was -- it was decided in 2005, so we shouldn't interrupt it or interfere with it. Well, we have had a number of people who have in fact addressed the issue that in fact, yes, it should stay except for our piece. Mr. Knecht is saying basically that.

With respect to the CARD, you shouldn't really do much about the CARD, except where I think it should be revisited. Mr. Sollows, has indicated that he, too, I think had some question about the accuracy of it to the point where he has advanced this concept of a 55/45 split, which to my nontechnical knowledge -- I haven't got two clues about what kind of an impact that has on the revenue to cost ratio, except I think it would have significant upward pressure to use words of Mr. Larlee, on the revenue to cost ratio by reducing the 60 percent down to 55 percent for the allocation of the firm fixed costs.

Vibrant Communities again, I think agreed that there should be a CARD. And EGNB has and J.D. Irving has. So when you look at, most of the parties have in fact in some fashion said we need to revisit the CARD issue. Again, Mr. Drazen, he did not -- it was pointed out by one of the intervenors, he did not do a full CARD hearing. All I can say is thank goodness he didn't do a full CARD study, we would still be here.

All he was trying to do was point out the need for one and for the need for this Board to give consideration to the fact that it is -- the 2005 one is not sufficiently reliable to be able to say .92, .96, .97. Where is it? It's in the order of magnitude. He said .97 is where he believes an adjustment would take him. He is not saying that's the definitive answer for a new CARD cost study.

And then lastly with respect to the Public Intervenor's -- Mr. Knecht's idea of a 9.6 rate increase, I guess I don't like to end it on the doom and gloom, but the last thing in the world I want to see this Board consider is the idea that making the revenue to cost ratio for large industrial customers an academic issue, because that kind of thinking could well result in us not having to worry about what the revenue to cost ratio is in the large industrial class, because we know where unfortunately they are headed now. To add that kind of an extra burden, independent of the revenue to cost ratio, which I think don't justify it in any event, but independent of that, hollowing out of the large industrial class I would say is to nobody's advantage.

Unless there are any questions, I would thank you very much.

CHAIRMAN: Thank you, Mr. Lawson. Mr. Morrison?

MR. MORRISON: Thank you, Mr. Chairman. I will try to be brief. I will deal first with the Public Intervenor's argument. I really have very few comments with respect to that argument. A great deal of his remarks were directed at what he believes this Board should recommend to government, and as it doesn't really relate to any matters before you in issue, the decision I am really not going to comment on his comments in that regard.

He did ask the Board to declare your jurisdiction over the PPAs. And as a result of that make several rulings. That DISCO submit any amendments to the PPAs to the Board. That DISCO file a monthly cost data with the Board, et cetera. With all due respect the Board cannot declare its jurisdiction over the PPAs or over any thing else for that matter. You either have jurisdiction or you don't. And given the present legislation, you currently do not have regulatory authority over the counterparties to the PPAs.

Mr. Theriault also wants the Board, and I was quite surprised at this actually to establish several deferral accounts. It was not part of DISCO's application for deferral accounts. As far as I can recall, there was no -- nothing came significant in cross examination. The Public Intervenor has filed no evidence to support the establishment of deferral accounts.

Clearly there is no evidenciary basis upon which you could make decisions on such complex matters as the establishment of several deferral accounts with the evidence that you have before you today.

I do have to -- and I was hoping I wouldn't have to, but I do have to address this issue of this - which came up yesterday and again today, about prorating this $47 million. CME, Mr. Wolfe, I believe Mr. Zed have all urged the Board to prorate the $47 million portion of the PDVSA settlement based on the value of the claim set out in the pleadings as I understand their remarks.

CME says look the value of the claim is $2.2 billion. NB Power recovered 333 million, which is about 15 percent of the claim. So the province should only recover 15 percent of the 47 million or $7 million. That's what I understand the logic to be. And JDI makes a similar argument only suggesting something somewhat different. They are suggesting that you may look at the refurbishment costs of $702 million, in which case the provinces prorated portion would be 50 percent. So you split 40' -- so you split the 47 million.

First, forget about the $2.2 billion for the reasons discussed yesterday and for the reasons I mentioned in the in-camera hearing. Regardless of whether you base it on the 2.2 billion or the 700 million, it is my submission that the notion of prorating the $47 million is just wrongheaded. It appears to be based on some in my view distorted view of the principle of quantum meruit. And the key word in that is meruit, which means merit. And in my submission there is simply no merit in compensating DISCO's ratepayers for a loss they did not incur As I mentioned yesterday, the ratepayers did not pay the $47 million and they should not receive compensation for a loss they did not suffer.

However, if the Board -- if the Board contemplates allocating some or all of the $47 million to customers, as some people have suggested, it must be dealt with through the deferral account on a prospected basis. There is no accounting or regulatory basis for the Board to apply the amount against DISCO's revenue requirement in the test year. Nor is there any accounting or regulatory basis on which to apply the amount over an arbitrary period of two, three or four years, as suggested by Mr. Lawson, or five years as suggested by Mr. Wolfe.

The PDVSA settlement, the $333 million represents a recovery of damages incurred by NB Power's spending capital to prepare the Coleson Cove plant to receive and burn Orimulsion fuel. Capital that it would otherwise would not have spent. Generally accepted accounting principles dictate that the accounting for the recovery follows the accounting for the original expenditure, as was affirmed in the Deloitte & Touche report. And of course that's exhibit A-38. If the Board determines that some or all of $47 million should go to DISCO, in other words, it's a recovery of capital spent on behalf of the ratepayer, then it would receive the same accounting treatment as the rest of the settlement. It would be credited to the capital cost of the Coleson Cove plant, period. Savings to DISCO would flow in the form of reduced amortization through the PPA into DISCO's deferral account. The Board has already determined how amounts flowing into the deferral account are returned to ratepayers, that is, over 17 years.

Also the PDVSA settlement is a one time event. Crediting any portion of it directly to ratepayers as a reduction of the revenue requirement in this year, the test year, and therefore a reduction in rates, would leave DISCO underrecovering its rate base on a continuing basis. At some point, in a year or perhaps two years from now, a very large rate increase would be required in order to get base rates back to the level where they are recovering costs.

I would like to talk about the CARD hearing. And Mr. MacDougall, CME in particular raised the issue and they referred to several sections of the Electricity Act. I will deal with Mr. MacDougall's first. He basically said that authority can be found in Sections 101(4), Section 128(1)(b) or Section 130 of the Act to give you authority to order a CARD hearing.

I looked at Section 101(4) and Mr. MacDougall just referenced it, and I don't believe it has any application to the conferring of jurisdiction. I think what that says is when you are conducting a rate hearing you can take into account cost allocation matters.

The other sections are more ambiguous. In any event, I believe it is fair to say that jurisdiction is questionable and I would also say that the same comments on the questionable jurisdiction would equally apply to Mr. Kidd's argument or suggestion that there be an integrated resource planning or DSM hearing ordered for I believe October 13th.

More important though when we are talking about this CARD hearing is Mr. Lawson's suggestion yesterday that you extend the present interim rate and call it a conditional rate. Quite frankly we are really talking about semantics here. The fact that it is without a final rate the accounting rules probably would not permit DISCO to recognize any revenue -- the revenue this year, and all of the uncertainties and difficulties I talked about yesterday in my initial argument would remain.

DISCO is concerned with the timing of the CARD hearing. CME's witness, Mr. Drazen, said, and it's at 1922 of the transcript, that the Point Lepreau refurbishment will result in an anomalous period of costs during the outage and that a CARD hearing might be best dealt with after that event is over. DISCO agrees and as well does not want to incur the time and expense of a CARD hearing unless there is new information or a change in underlying costs that will likely result in improvements to the current methodology.

I only have two more points that I would like to make and it's with respect to the hedging policy. It rises out of comments from Mr. Wolfe primarily. Mr. Wolfe said that the hedging policy should be altered to more closely follow the markets. That's what he said in his argument yesterday. What he is suggesting is that the conservative mechanistic approach currently used for hedging be abandoned. He is suggesting that DISCO get into what I would call the market speculation game. This is very high risk and in my view imprudent. I doubt very much that a regulator such as yourselves would consider it to be prudent -- consider it a prudent hedging policy that would expose DISCO to such enormous market risks.

In his final argument Mr. Wolfe argued against including hedging losses in the setting of the vesting energy price. He further stated that since the time of the setting -- sorry -- setting the vesting price the hedged losses have declined because heavy fuel oil prices have increased. Then he concludes that DISCO has been charged for the losses and now Genco is getting a windfall because the hedged losses have declined. This statement is really a complete misinterpretation or a misunderstanding of how the hedges work. It is completely inaccurate to say that DISCO absorbs losses and Genco gets a windfall. DISCO is charged a fixed price based on the hedged contract and that is the same amount Genco pays when it purchases fuel as DISCO's agent. Mr. Wolfe is correct in saying the hedged losses declined after the setting of the vesting energy price.

In fact, heavy fuel oil hedge settlements have moved from a loss position to a gain position as heavy fuel oil market prices have increased, and that was in response to an October 28th IR -- CME IR-56. But the combination of the changed market price and the changed settlement, which is now in a gain position by the way, still equal the fixed price obtained in the fuel hedge contracts. There is no loss for DISCO and no gain for Genco, as was implied by Mr. Wolfe.

I will just touch briefly on the DSM hearing that was proposed by Mr. Kidd. I question whether there is any jurisdiction. In addition what he is really asking for if you get into that is asking this Board to take over the integrated resource planning process, because that's where DSM comes into play when you are looking at basically capacity options. The integrated resource planning process is basically about meeting the electricity requirements of DISCO's customers. That is now addressed in the Electricity Act in Section 80(1) and 80(2) which states that the Board must approve the process where DISCO goes out for an RFP for new capacity. That's how DISCO gets new capacity now. It has to come to this Board, get an approval for an RFP process and then go out into the markets to get new capacity. So therefore in my submission until there is an RFP for long-term supply of electricity, or until one is required, the Board really does not have any jurisdiction over the capacity planning process.

The last item I would like to deal with, and very briefly, comes out of something that CME mentioned, it was about the loss of industrial customers, the closing -- the recent announcement of mill closures. CME says that the loss of industrial customers impacts rate design. Loss of industrial customers is a serious issue to DISCO and to New Brunswickers alike. However, it does not impact the rate application because rates, as we have discussed many times, are set on a prospective basis. And of course as I have argued in the past, Section 101(3) requires the Board to set rates on a prospective basis. Just because this hearing is ongoing within the test year does not alter this reality. So the loss of those industrial customers has no impact on the revenue requirement for the test year.

And I was longer than I had hoped to be, I apologize for that, but those are all my comments in rebuttal. Mr. Chairman, I would like to thank you, the Board and particularly the Board Staff and all the intervenors for all of your -- everyone's assistance in getting through this long and arduous process and maybe that is the way it should be. And I would like to wish you and your families and all the intervenors and their families a very Merry Christmas. Thank you.

CHAIRMAN: Thank you, Mr. Morrison. I guess just in concluding the hearing I also would like to make just a few comments about the last four weeks and the conduct of the hearing. It is somewhat intense I guess when you get into a hearing that lasts over a period of four weeks and things have gone very well, and I just want to acknowledge the people that have made it work. Our sound technician, it has worked flawlessly. Our translators. Our court reporter and her associates at Henneberry Reporting Service for getting the transcripts delivered in such a timely fashion. Even the media in taking the photographs and whatnot have done it in a manner which has allowed us to proceed without really being interrupted. I want to acknowledge the Board Staff, which has worked very hard on these hearings, including our Secretary and our Assistant Secretary. Certainly Board Counsel, our advisors and the support staff back at the office. I also want to commend all of the parties, their counsel and their staff for the professional and courteous manner in which they have conducted themselves during the course of this hearing. I can assure you that the Board has appreciated it.

I guess everybody wants to know when will we get a decision. Well I can tell you that the Board will get at the job of dealing with all of the evidence and arguments the very early part of the new year. Obviously at this point in time it would be difficult to know precisely when a decision would be rendered, but I can tell you that we will work very diligently during the month of January with every hope and intention to try to put our decision out at the end of January or early February at the latest. I hope that I don't have to revise that estimate.

In any event, I think everybody here has earned a well deserved Christmas break. So I hope that everybody here and their families do also enjoy a good Christmas.

Ms. Desmond, is there anything further that we need to do before we adjourn this hearing?

MS. DESMOND: Nothing further. Thank you, Mr. Chair.

CHAIRMAN: Anybody else feel that there is anything else that needs to be done? I think the record is closed. We will adjourn. Thank you.

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

Reporter