New Brunswick Board of Commissioners of Public Utilities

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

Fredericton, N.B.
November 10th 2005

Henneberry Reporting Service

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CHAIRMAN: David C. Nicholson, Q.C.

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BOARD COUNSEL: Peter MacNutt, Q.C.

BOARD STAFF: Doug Goss
John Lawton
John Murphy

BOARD SECRETARY: Lorraine Légère

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CHAIRMAN: Good morning, ladies and gentlemen. Could I have appearances for the record this morning? For the Applicant?

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

CHAIRMAN: Thanks, Mr. Morrison. Canadian Manufacturers and Exporters? Mr. Plante I believe had another engagement so he is not here today. Conservation Council? Maybe on the way to Saint John. Eastern Wind is not here. Enbridge Gas New Brunswick?

MR. MACDOUGALL: Yes, Mr. Chair, David MacDougall representing Enbridge Gas New Brunswick.

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

MR. BOOKER: Mr. Chair, Commissioners, good morning. Andrew Booker for Irving.

CHAIRMAN: Andrew Booker. Thank you, Mr. Booker. Jolly Farmer is not present. Rogers Cable is not present. Self-represented individuals are not present. Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman and Commissioners. Ray Gorman appearing for the Municipal Utilities. Today I have Dan Dionne, Charles Martin, Michael Couturier, Eric Marr, Dana Young and Jeff Garrett with me.

CHAIRMAN: You do have a good turnout this morning, Mr. Gorman.

MR. GORMAN: Thank you.

CHAIRMAN: Vibrant Communities Saint John. Public Intervenor?

MR. HYSLOP: Good morning, Mr. Chairman. Peter Hyslop with Mr. O'Rourke, Mr. Barnett and Ms. Power. Thank you.

CHAIRMAN: Thank you, Mr. Hyslop. Mr. MacNutt, who is with you today?

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

CHAIRMAN: Thanks, Mr. MacNutt. The Board has a preliminary matter and that is at the very beginning of this hearing process, the Canadian Council of Grocery Distributors sent us in a written submission and we have looked at it and frankly it -- and in the covering e-mail it said a written submission of the Canadian Council of Grocery Distributors to the Board - proposed rate increase. Please distribute accordingly.

And frankly, we believe that is more appropriate in the rate portion of this hearing and we will file it there. I just wanted it on the record that it hasn't been ignored and we did receive it.

Any counsel have any other preliminary matters?

MR. MORRISON: Yes, Mr. Chairman. We are now in a position to respond to our final undertaking which dealt with the seasonal storage issue. And I believe copies have been provided to the Secretary.

CHAIRMAN: All right. And this is response to undertaking number 3 requested on the 6th of October 2005. Mr. Sollows is not an Intervenor, but I understand why you have got him cast in that role.

MR. MORRISON: My apologies.

CHAIRMAN: Talk about a Freudian slip. Okay. My records indicate that would be A-53. Thanks, Mr. Morrison. Anything else?

MR. MORRISON: The Board asked us to address four questions yesterday and I don't know whether you want us to do that up front or in the course of when we are called upon to do our rebuttal.

CHAIRMAN: Well I will ask counsel what they think. I mean, we just wanted you in your rebuttal to talk about those questions. If it would be the preference of counsel that each of you go in accordance of the ordinary order of participation in cross, then do your rebuttal after that, why, then giving you therefore a chance to comment on what anybody else has said in reference to the responses to the four questions, why, we are open to that suggestion. That is fine. Take a minute and just see what counsel think.

MR. MORRISON: Mr. Chairman, we may as well do it now so that is out of the way.

CHAIRMAN: Okay, fine. Well then I might as well go ahead with you, Mr. Morrison.

MR. MORRISON: Thank you, Mr. Chairman. The first question, do parties believe that the interruptible rate should include a contribution to fixed costs and if yes, how much of a contribution?

The answer is no. Disco's approach is consistent with the Board approved method from the 1992 CARD hearing. Because they are interruptible, there is no demand cost component.

The second question was do parties consider that the interruptible rate option should be made available to other rate classes and if so, which classes.

Disco has two non-firm rates available to individual customers -- sorry, to industrial customers. The interruptible rate is available to self-generation or co-generation, as per the Rate Schedules and Policies Manual. To date only large industrial customers have this capability.

Should other customers, particularly distribution customers, opt for self-generation, a rate that reflects their cost of service could be developed. The surplus rate could be made available to other classes if they can demonstrate the interruptibilty requirements of the rate. To date only large industrial customers have requested this rate and have been able to meet the operational and administrative requirements.

The third question, do parties believe that it would be appropriate for Disco to develop a curtailable power demand response option whereby customers would be paid to curtail or eliminate their load at times of peak demand. And our response to that is Disco currently has customers on a rate similar to the rate described, curtailable. However, it is closed to new parties -- new participants. Opening the rate and reevaluating the eligibility and restrictions under the rate may be viable as capacity becomes more constrained and during the Point Lepreau refurbishment.

However, Disco sees no need to pursue this option in the 2006/07 timeframe and there are practical considerations to be considered curtailing small loads, any system requirements for notification of these small loads, et cetera. So there are some practical considerations.

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

Disco recognizes the logic of the premise of the question. One result of Disco's approach to export benefit classification is that for low load factor customers -- the low load factor customers receive a larger share of export benefits.

Other benefits of low load factor -- of low factor load are likely insignificant. Reserve requirements are driven by the largest unit and maintenance would likely be possible without added capacity due to the diversity of the plant resources.

And those are our responses, Mr. Chairman.

DR. SOLLOWS: Yes, Mr. Morrison. You said that the -- there are operational and administrative requirements related to the supply of surplus energy. Are those requirements documented and on-file with the Board?

MR. MORRISON: It is my understanding that it is part of the RSP Manual but in order for customers to meet the eligibility requirements they also have to meet the market rules as well. So I believe it is documented somewhere, Commissioner Sollows.

DR. SOLLOWS: So it is really established only for transmission level customers, below transmission level they wouldn't have to relate to the market rules?

MR. MORRISON: That is correct.

CHAIRMAN: Thanks, Mr. Morrison. Mr. MacDougall? I am going to interrupt. Go ahead. Sit down. Mr. Goss, have you got any more of the questions typed up and available?

No. Okay. That's good.

MR. MACNUTT: No, we don't.

CHAIRMAN: All right. Thank you. Go ahead, Mr. MacDougall.

MR. MACDOUGALL: Certainly, Mr. Chair. Based on your last comment, would you like me to read the question before I answer it, if some people don't have the questions, would that be helpful?

CHAIRMAN: Probably a good idea.

MR. MACDOUGALL: So the first question was, do parties believe that the Interruptible Rate should include a contribution to fixed costs and if yes, how much of a contribution?

Our response is generally, yes. All rates, unless based strictly on non-economic policy considerations such as economic development or load retention rates, should at least cover their variable costs and make some small contribution to fixed costs. However, as interruptible customers do not impose or cause any capacity costs on the system, i.e., you do not have to plan capacity for interruptible customers, their contribution to fixed costs can and is usually correctly quite small.

The second question. Do parties consider that the Interruptible Rate option should be made available to other rate classes, and if so, which classes?

Our response is that generally residential and GS-type customers do not have interruptible rates as we know them now in New Brunswick. The first issue is in order to determine if a customer complies with the interruption, all such customers would require interval metering. This would likely make the benefit they would bring possibly not commensurate with the cost. Plus such customers would generally only provide very small blocks of interruptibility and any meaningful interruptibility would require enormous response from a whole host of smaller customers and that would bring with it the administrative burden of both contacting such customers and verifying their interruption.

Also in most jurisdictions, there is usually random checks or some proof that a customer actually can or will interrupt and also interruptible rates usually bring with them a serious penalty for failure to interrupt, since what you are asking for the customer to do is to interrupt. And it's unclear that residential or GS-type customers would be willing to face such penalties.

So it's not common and there would be certainly clear administrative, as well as, metering issues.

The third question. Do parties believe that it would be appropriate for Disco to develop a Curtailable Power

(Demand Response) option whereby customers would be paid to curtail or eliminate their load at times of peak demand?

Our response is that you could certainly develop an optional program, and not in lieu of existing rates would be our suggestion, but again it's the cost of developing and administering that program should be demonstrated to be outweighed by the benefit and the potential take-up.

But again, because it's curtailable power, it could be put forward as an option, but one would certainly want to determine how big the curtailable blocks are, how much you would have to curtail, the period of curtailment. It's not as simple as just stating there should be an option available.

And 4) do parties believe that there are benefits to the system from the presence of low load-factor customers in the areas of generation maintenance, reserve requirements and generation availability for export sales, and if so, are such benefits properly calculated by the cost of service study?

Well, the simple answer in our perspective is no.

However, to elaborate on this, it would be somewhat like the tail wagging the dog. Utilities want to use their generation plant, which is very capital intensive in the most efficient way possible, i.e., they want to run their plants flat out. And I believe Mr. Ketchum confirmed this on cross-examination by myself. And I believe Dr. Rosenberg referred essentially to a similar question and gave that response to Commissioner Sollows.

High load factor customers allow this. These are the type of customers utilities look for. Low load factor customers are the most inefficient users of the system. They add costs to the system. And these costs are what should be apparently reflected in the class cost allocation study. And this is what is generally done in all other jurisdictions.

Benefits, such as suggested in the question, are never to our knowledge reflective in class cost allocation studies, for the simple fact that the customers do not create benefits, as the maximum capacity is built because the low load factor customers need to be served in the peak times. And the capacity -- the remaining capacity built to serve them is often under utilized. And in fact Commissioner Sollows referred to how much peaking capacity was actually being used in New Brunswick.

With respect to the specific items on exports, the issue with exports is that the utility, not just New Brunswick, but any utility is just making the best of a bad situation caused by the low load factor customers. You don't build your plant for exports. You build it to serve native load. You do not want to encourage low load factor customers.

With respect to reserve requirements, I believe Mr. Morrison mentioned the reserve requirements are not tied to the load factor. They are tied to the biggest unit on the system. And they are also -- you have to ensure you have reserve that covers your peak demand. So a low load factor customer really has no impact on what the reserve requirement would or should be.

And with respect to generation maintenance, again, this is why in a fully flat system, if you had the benefit of all of the correct customers, you would credit interruptibility, because interruptibility then allows you to do that.

But again merely because you can do maintenance in a time period because you have built for low load factor customers is no reason to give a benefit to the low load factor customers, because they have caused you to essentially over build your plant to start with.

It's their costs that have to be reflected and we are not aware of any situations where a utility would suggest that a low load factor customer brings any benefit to a system.

Although, we do understand that you can export in those months, but that is just -- as we say, that is just making the best of a bad situation created by a system where you have to serve your very peaky winter load. For example, in the US, in those jurisdictions where they have a summer peak and a winter peak, then that works better. Then they don't export. But that's because they have two peaks. Here we have one and we just use exports because we have the opportunity to use capacity that's otherwise billed.

Those are our comments, Mr. Chair.

CHAIRMAN: Thanks, Mr. MacDougall. Thank you. Mr. Gorman?

MR. GORMAN: Thank you, Mr. Chairman. In response to the first question, do parties believe that the interruptible rate should include a contribution to fixed costs and if yes, how much of a contribution?

Our response is as follows: Yes, it should include a fixed cost component. This shares the benefit of those sales with other customers. However, there may not be sufficient information before the Board now to determine the appropriate amount.

Question number 2. Do parties consider that the Interruptible Rate option should be made available to other Rate Classes, and if so, what classes?

Our response is that our preference is not for a curtailable -- sorry, is for a curtailable rather than an interruptible, where the distinction is that there are broader criteria for the interruption such as price, rather than purely system reliability. A curtailable arrangement can be implemented for various types of loads and classes.

The third question. Do parties believe that it would be appropriate for Disco to develop a Curtailable Power (Demand Response) option whereby customers would be paid to curtail or eliminate their load at times of peak demand?

Our response is yes. Some examples in the residential class would be incentives for water heater load control or storage of space heating. A fixed long term policy for rate design that supports these incentives is necessary for customers or utilities to make the capital investment necessary to support these programs.

The fourth question. Do parties believe that there are benefits to the system from the presence of low load-factor customers in the areas of generation maintenance, reserve requirements and generation availability for export sales, and if so, are such benefits properly calculated by the cost of service studies?

Our response is that benefits are provided by having a mix of customers on the system. Different load profiles support a variety in the generation mix. To the extent that annual coincident demand is used to allocate costs, a penalty is imposed on low load-factor customers who are coincident with the peak. Benefits are shared with low load factor customers by utilizing methods that allocate some component of fixed costs based on energy. This is well reflected in the 40/60 methodology previously approved by the Board.

Those are our responses.

CHAIRMAN: Good. Thanks, Mr. Gorman.

MR. GORMAN: Thank you.

CHAIRMAN: Mr. Hyslop? If you would bring both arguments forth with you, because we are going to reverse the batting order now.

MR. HYSLOP: Thank you, Mr. Chair. I filed with the Secretary this morning written responses to the four questions. But I think in view of the procedure, I would like to have the opportunity to briefly read the answers onto the record. Okay.

And I would advise the Board in terms of rebuttal, that I have none from yesterday, since that's the second part it. So that will go fairly quickly. And other than any further reservation we might want to make as an addendum to our order from these questions that is --

CHAIRMAN: Have you been working on the fact situation overnight?

MR. HYSLOP: In any event, I couldn't get Mr. Morrison to consent to the order yesterday, Mr. Chair. So we are going to have to ask you to make a decision.

In any event, the answers to the four questions posed.

Question 1. Do parties believe that the Interruptible Rate should include a contribution to fixed costs and if yes, how much of a contribution?

a) our first part of the answer. Surplus interruptible customers currently make a contribution of $3 per megawatt off-peak and $9 per megawatt hour on-peak above Genco's incremental cost (after firm load), primarily to recover transmission costs. Disco is billed under the OATT for interruptible load, and therefore this contribution must be retained, unless at some point the Board changes the OATT. On this point, we are in disagreement with our friends from the EA.

A second, as Mr. Kencht noted at page 40 of his pre-filed evidence, many utilities do indeed charge a premium to the cost of interruptible service to reflect the value of that service to those customers. We therefore believe that there are credible rate design reasons why interruptible/surplus rates could be priced modestly above costs.

And c) while there is little evidence on the record regarding the appropriate contribution, it would be our view, in addition to the comments we made yesterday, we suggest that the 105 percent upper bound for the revenue-cost ratio is not unreasonable. Disco (PUB) 76 dated July 14th 2005 indicates the average interruptible rate is $58 per megawatt hour. 5 percent of this would be approximately another $3 per megawatt hour and we would make that recommendation to the Board.

Question 2. Do parties consider that the Interruptible Rate option should be made available to other Rate Classes, and if so, which classes?

At this stage, we are concerned that NB Power has too much interruptible/surplus load, rather than too little. As detailed in our argument, the interruptible/surplus customers have only been interrupted only 6 times for a total of 14 hours since 1999. We prefer to look at this as "near firm" service. For this reason, our focus is more on setting the price for the existing interruptible closer to the nature of the service that is received rather than expanding the interruptible surplus load.

To the extent that interruptible load will have a value in the next few years, it may be that during the period Lepreau is down for refurbishing. And to that extent we want to respond that we ought to do it in a specific temporary basis -- we don't want to see anyone putting in thermal mechanical pulp mills expecting to get cheap interruptible surplus power for the next 30 years.

From a practical point of view, the easiest way to get interruptible is from the large industrial loads, because you get the greatest reduction from having to throw a single switch. Moreover, with larger customers who have contract demands, it is easy to identify how much capacity is really interrupted. However, it is our understanding -- and we don't want to discount this fact, that demand-side management technologies do exist whereby appliances can be shut down remotely by the utility. We do not object to Disco investigating the costs and benefits of expanded DSM programs, but at this point we do not see the need for aggressive expansion of the interruptible service.

Question 3. Do parties believe that it would be appropriate for Disco to develop a Curtailable Power (Demand Response) option whereby customers would be paid to curtail or eliminate their load at times of peak demand?

The first part is we reiterate our concern about too much interruptible power.

b) In theory, interruptions provide value when costs avoided by the interruption, namely the marginal cost incurred by NB Power (including the opportunity cost of export sales), exceeds the rate being paid by the customer. Thus, to the extent a customer is entitled to power at rates below marginal costs (or as a proxy for market price), there is some value in sharing that benefit by paying customers not to take the service. However, the devil is really in the details -- how do you figure out how much load was actually reduced by a residential, commercial or even industrial customer? In our view, if we are trying to get ratepayers to react when market prices are high, we should be looking at creative ways to get customers to self-interrupt -- by pricing marginal use of energy as close to market prices as possible. However, having said that, we can see we have a long way to go before our residential tail block starts to reflect marginal costs.

Do parties believe that there are benefits to the system from the presence of low load-factor customers in the areas of generation maintenance, reserve requirements and generation availability for export sales, and if so, are such benefits calculated by the cost of service study?

a) Regarding generation maintenance -- yes, there is likely to be a benefit associated with low-load factor load. And we believe that the unadjusted EP method reflects that benefit, because the only demand-related costs are those related to the peaking units -- low load factor customers are not being disproportionately charged for the fixed costs of the baseload plants. By way of contrast, Dr. Rosenberg's methodology does not recognize those benefits -- because he assigns the duration costs on the basis of the optimal breakeven analyses. For example, he assigns a coal unit duration cost based on nine months of energy use, which excludes the summer, even though the coal units could be down during the summer months, when industrial customers represent a larger share of the load. And finally, as I think all of the intervenor experts agree, Disco's proposed allocation system has nothing to do with the benefits to the actual generation system, since Disco relies on the PPAs, or at least sort of, and therefore cannot possibly reflect this particular benefit.

b) Regarding load factor, it's possible that if all customers were hight load factor that the reserve margin would have to be somewhat higher. Again the EP methodology probably best reflects this benefit, because low load factor customers are charged for capacity costs relating to a peaker unit.

c) And finally, regarding availability of export sales, the valleys are created by low load factor customers, particularly in the summer months when prices and demand are strong in the New England markets, and provides significant benefit to NB Power by making available the capacity used to earn export margins. Now we suggest there are a couple of ways of looking at this problem. First, it could be argued these margins are really a cost credit, and they should get assigned to those customers who pay the fixed costs of the plant. To be honest, none of the experts in this proceeding have allocated the export credit on the exact same basis that they allocate the plant fixed costs, but that is one solution that does not seen to be unreasonable. However, it seems that it also could be argued that high load factor customers are not responsible for any of the export sale, because they have no valleys to fill in, and therefore, they should get assigned very little of the benefit. In effect, you would be allocating export revenues on the basis of the difference between the peak demand and the average demand to recognize the valleys created. Of course, no one has presented that either.

So given these considerations, we suggest that a) the matter be given some additional study for the next proceeding and b) in the interim, we continue to use the existing method whereby all credits are allocated on a demand basis.

Those would be our submissions. And as I have indicated, these have been provided as a written document to the Secretary, Mr. Chairman.

CHAIRMAN: Thanks, Mr. Hyslop. And your rebuttal, if any?

MR. HYSLOP: I have no rebuttal, Mr. Chairman. And I also did file this morning the text of my verbal comments yesterday so -- with the Board.

CHAIRMAN: The decision.

MR. HYSLOP: Well, if you -- you can cut and paste as you please, sir.

CHAIRMAN: Well said. Thanks, Mr. Hyslop.

MR. MORRISON: I would suggest just cut, Mr. Chairman.

CHAIRMAN: Mr. Gorman?

MR. GORMAN: Thank you, Mr. Chairman. We have no rebuttal.

CHAIRMAN: Mr. MacDougall?

MR. MACDOUGALL: I am going to break that trend, Mr. Chair.

CHAIRMAN: It was bound to happen.

MR. MACDOUGALL: Mr. Chair, Commissioners, we have a little bit of rebuttal for both Mr. Gorman and Mr. Morrison. I do apologize, I have a little more lengthy rebuttal to Mr. Hyslop. But as you would have recalled yesterday, he made a significant amount of comments specific to the direct application of Dr. Rosenberg's evidence, which we do not believe are correct and we would like to provide our views on those to the Board.

First off, Mr. Hyslop made some comments respecting Dr. Rosenberg's so-called 95/5 split for Coleson Cove. Now to start out, this is the split that is shown in NB Power's updated Peaker Credit Method, which was filed in response to EGNB IR-36 on August 5, 2005.

With the greatest of respect to Mr. Hyslop and his expert, we believe they continue to miss the point here. If you used a different split for Coleson Cove, say 75/25 in the Peaker Credit Method, then you would not get the 40/60 split derive and go to the Peaker Credit Method at the end of the analysis.

And there would be no basis for the 40/60 split, which now Mr. Hyslop says the Board should just apply even if the Peaker Credit Method doesn't support. But Mr. Knecht, his expert, accepted the Peaker Credit Method. So we are confused.

No one complained about the Peaker Credit Method in this proceeding. But now Mr. Hyslop wants you to use the end result that derives from Dr. Rosenberg and Disco's application of the Peaker Credit Method to Coleson Cove, i.e., you get a 40/60 split when using the numbers from EGNB IR-36, but ignore the method which supports this. This makes very little regulatory or economic sense.

We know we spent money for Coleson Cove's recent refurbishment, which is not fully reflected in the response to EGNB IR-36. And if reflected it would show less percent demand and more percent energy. But the Peaker Credit Method states that extra capital was spent to save fuel, i.e., any costs above those of a CT are to save fuel. But we didn't save any fuel.

Mr. Hyslop, himself, yesterday, referred to the two numbers and I am not sure if these are correct, but his numbers were we would love to have the $22, but we are seeing $72 per megawatt hour.

So we didn't spend capital to save fuel, because we haven't saved any fuel. If and when Coleson Cove does save fuel, it would be appropriate to then recognize both sides of the coin. IR-36 did not reflect the Coleson Cove extra capital, that's true. But the fuel expense in Disco's cost of service study never reflected any fuel savings. So that approach is balanced.

Dr. Rosenberg's approach has the capital costs for Coleson Cove consonant with the fuel costs for Coleson Cove.

There is no hit to the residential class.

Mr. Hyslop's view is constantly that what one is doing is driving costs to the residential class. That was not Dr. Rosenberg's mandate and that is not what his evidence shows. He approached this from a perspective of what he felt was appropriate cost causation.

With respect to the use of January in his analysis, again, there is no hit to the residential. Dr. Rosenberg's breakeven analysis showed the breakeven point between a CT and a CC unit, combustion turbine unit, which is the next least capital expensive, as 668 hours. That is the breakeven point.

This is the 668 -- this is the top 668 hours, i.e., a CT is a true peaker and it is used at the top of the stack.

So what we are talking about in the breakeven analysis for a CT, is the top hours of the year, that's when it is going to be used.

But Dr. Rosenberg did not have the data for the top 668 hours, because it wasn't available. So he used January, a month with 774 hours, because he had the monthly data and January is the appropriate month to use, because it is the month in which you have the top peaking hours. You don't use a summer month to recognize a peaker.

Again, we have no idea what Mr. Hyslop was getting at. January is the proxy for the 668 hours of the use of the CT. So if you use a CT in the top 668 hours and you don't have that data, you must use an appropriate proxy.

Again, that is what he did. So I just want to point out to the Board exactly the basis for his use of January.

And the third point Mr. Hyslop then challenged was how Dr. Rosenberg treated fuel costs of the combustion turbine.

But again he treated them completely consonantly with the way he treated capital. No one, as far as we can recall said in their evidence that he was allocating fuel costs incorrectly. We do not believe that is in the testimony. It may be. But certainly we are not aware of it.

If a customer class was getting a bigger share of Coleson Cove's costs, then they were getting a bigger share of Coleson Cove's megawatt hours. The same with all of the other units. And he did this with all of the generation.

I think it's very important, you know, considering the comments made by Mr. Hyslop, and I believe by Mr. Knecht on this, that we refer to -- and we don't have to pull it up, because I just want to read it in. But it's at the bottom of page 35 and the top of page 36 of Dr. Rosenberg's evidence.

This is where he explains what he did. And I commend this to the Board so nothing on the record is confusing. How do you propose to allocate the fixed generation cost in the cost of service study? Because NB Power did not have class data on an hourly basis, I propose to allocate the fixed costs of the oil/gas-fired generation and purchases on the basis of each classes firm energy for the month of January. January has 744 hours, which is close to the 668 hours from the breakeven point analysis. Any usage in other hours is not germane to the decision to build this type of plant instead of a Peaker, a CT.

Similarly, as noted above, the breakeven point between a combined cycle plant and a coal plant is 6,420 hours.

Consequently, I allocated the duration-related portion of the Belledune and Dalhousie, i.e, coal, pepcoke, Orimulsion plants in proportion to the total energy usage of each class in the months October through June. The nine highest intensive energy usage months, which total 6,552 hours.

Again, as you go down the classes, you use the highest months, because that's what we are comparing, the most expensive to the least expensive and the next least expensive, to the next least expensive. Then he goes on to to say, since any energy usage beyond that point would have no impact on the decision to build a coal plant. What's very important is the top of page 36. However, I did allocate the duration portion of the nuclear and hydro fixed costs entirely on annual energy. And this is because hydro is treated differently and because nuclear, as it was stated in his testimony is above 8,760 in a breakeven analysis, more hours than any year. As I explained in my previous answer, this expedient gives the benefit of any doubt to the low load-factor classes. Particularly, the residential heating customers and the general service II customers. That was not challenged. We commend it to you. It's at the top of page 36. If anything, Dr. Rosenberg in some of his analysis gave the benefit of the doubt to the residential, the low load-factor customers, not to the high load-factor customers. What he did with respect to all customer classes, as if he looked at and developed the CCAS, which he felt was cost causative. He did not go from a starting point of deciding to shift costs to or from any class.

Now, Mr. Hyslop then says that residentials have had a 60 percent increase since 1993. But the point is, Mr. Chair, Commissioners, they are still below their cost of service. There is no balance that has occurred. They have not caught up to anything, as witnessed in NB Power's schedule 6.1 to their evidence.

Particularly, the electric heat customers. These customers are still below .9 percent on Disco's cost of service. They remain significantly outside of the range. We simply do not agree that they have caught up with anything.

Now with respect to the issue of export sales and this ties into some of the questions earlier, but Mr. Hyslop had made a comment as well and I think it ties into some of the comments he has made in his responses this morning, that we should made export sales -- you know, rather than serve the IT customers, you know, there is a benefit to export sales instead of interruption.

I have a -- as a lawyer, I have gone through this whole process without any law, but I have a little bit of law today. So I would like to hand that out if I could.

CHAIRMAN: I hope there is a New Brunswick case in there. Mr. Gorman certainly performed well in that regard.

MR. MACDOUGALL: He did, Mr. Chair. There isn't. There is only a Nova Scotia one, but I am sort of dual jurisdictional myself. And I do have to admit, Mr. Gorman's primary case yesterday was a Nova Scotia case of which I am abundantly familiar, let me tell you. And he adequately portrayed it.

This is not actually not a case per se. It's cited as a case, but it's a decision of the Nova Scotia Board. And to the issue of exports recently came before the Nova Scotia Board in the context of the value of exports and how they should be treated in a generic rate case.

So as you will see, this was a generic rate case in 2003. So it's very timely and in a very close neighbouring jurisdiction. And I think I would like just to bring this to the Board's attention to see what was said in that case and what the Board in Nova Scotia determined. And it's certainly our view that these are the exact same principles that apply in New Brunswick and in fact apply in all jurisdictions.

If we could turn -- what I have done is just given you the extracts on the issue dealing with exports. So I have given you the first two pages of the decision and the -- that has the citation. And this is available electronically and the pages dealing with the export issue. And if we could go to page 12, paragraph 37, you will see the issue.

In its pre-filed evidence, NSPI proposed to exclude ex' -- and that's the local utility -- to excuse export sales from the calculation of the RTP adders and 20-minute ahead prices. And that RTP is real time pricing, which is sort of a marginal rate form or rate design in Nova Scotia. NSPI agreed that exports generally have an upward pressure on marginal cost, since more load on the system will generally place higher cost units on the margin." However, it did not recommend excluding exports from the calculation of the GRLF rate. And that's the generation replacement and load following rate, which is also based on a decremental load, essentially a marginal-type priced rate. Although it is proposed to include the lesser of the average of the most recent five years of exports or the current year's forecast.

In its rebuttal evidence, NSPI reluctantly agreed to exclude exports from the calculation of marginal costs for purposes of setting the GLRF rate as well, given the unanimous view of the intervenors that exports should be excluded.

Then if we could go over to page 13, paragraph 41. And here there is a reference to Dr. Stutz. And Dr. Stutz was the witness for the Board in that case. Dr. Stutz recommended that exports be excluded from the calculation of costs used to set the RTP and GRLF rates. In response to questions from the Board, he agreed that export sales could lower rates for above-the-line customers. And these are your general embedded cost class customers. But it is appropriate -- but it is inappropriate to favour one group of customers at the expense of another group, all of whom form part of the native load served by the Utility. No Nova Scotia customer should be disadvantaged should be disadvantaged by reason of sales to out-of-province customers. NSPI has always given priority to serving native load before making export sales and its system was designed and built to serve Nova Scotia customers, not out-of-province customers.

In endorsing Dr. Stutz's view, SEB said: In other words, the quid pro quo for having a statutory monopoly within a particular jurisdiction is the duty to serve the customer load in that jurisdiction in priority and preference to load in other jurisdictions.

CHAIRMAN: Who is SEB?

MR. MACDOUGALL: SEB in that case were my clients, Mr. Chair.   They are Stora, Enso and Bowater Mersey, and they were represented by Dr. Rosenberg as it happens in that proceeding.

And then if we go to paragraph 45 on page 15, you will see a reference to Dr. Rosenberg and he was acting for Stora, Enso and Bowater. Advocated that export sales should always be excluded when calculating incremental costs for native load customers.

And then we can just go to the final part of the case, paragraphs 48 and 49. The evidence of the other parties focused on the issue of exports. There was a consensus that exports should not be included in the marginal cost calculation of the GRLF and RTP rates.

And then what's most important is the Board's findings in Nova Scotia only two years ago. The Board has reviewed the evidence presented with respect to marginal costs. And that's because some of these are marginal rate designs, the real time price and GRLF. Nova Scotia still has embedded costs for the above-the-line classes, but does have some marginal rate designs such as we discussed in this hearing.

The major issue in dispute is whether exports should be included or excluded in the calculation of marginal or incremental costs. The Board agrees with Dr. Stutz and Dr. Rosenberg that protection of the native load should be the primary consideration and therefore exports should be excluded from these calculations.

And Mr. Chair, Commissioners, I just commend that analysis to you. I don't think any jurisdictions that I am aware of state that one should treat exports before they serve the native load or determine what the appropriate rate structures are for the native load customers, interruptible or otherwise. That's the load that Disco, as the standard offer supplier, has to serve.

Exports again are a consequence of the plant it has built to serve its native load, not the other way around. And that was the decision in Nova Scotia and I commend you to try and find jurisdictions that would do otherwise. I am not aware of any.

So again, I think Mr. Hyslop's comments are sort of going to the fact that everyone should share in the exports. But you don't -- the exports are a benefit. That's at the end of the day. But you have to determine the rate of your native load appropriately first before you look at exports.

DR. SOLLOWS: Mr. MacDougall, can you just clarify for me is Nova Scotia Power functionally unbundled or an integrated utility?

MR. MACDOUGALL: Nova Scotia Power remains an integrated utility. We are in the process of moving to an Open Access Transmission Tariff, but that has not been finalized yet.

DR. SOLLOWS: Thank you.

MR. MACDOUGALL: But again on that point, Disco is still the standard offer supplier with the duty in the same sense as any integrated utility to serve all of the customers first. They are the standard offer supplier here. They must serve customers in New Brunswick.

And I think the other issues that Mr. Hyslop raised in that regard were reflected in some of our responses to the -- to the information -- to the questions asked by the Board yesterday.

So, Mr. Chair, I apologize for going into that in a little more detail, but I think it was necessary to clarify our position.

Just quickly now then to both Mr. Gorman -- actually I think I may have one other question -- point on Mr. Hyslop's. No, I think that's fine.

Again, Mr. Gorman yesterday continues to make the comparison between the large industrial classes so-called under recovery, not withstanding that they are within the 95/105 band, and the wholesale customers over-recovery, because they are closer to the 105, we would just reiterate the point that we made through our cross-examination of Ms. Zarnett. Now those two classes are within the band. The electric heat customers are well outside of the band. The residential customers as a whole are well outside of the band. The shift should come from the right customers.

Just because both wholesale and large industrial have access to the transmission tariff, that has nothing to do with cost causation of the customer classes as a whole. There is $50 million of under-recovery in Disco's study from the residential class outside of the band. There is 15 million of under-recovery from the large industrials in the band. Now where one would look? I just pose that hypothetical.

I don't know why the wholesale customers, if they feel there has to be any transference, wouldn't expect it to come from the class significantly outside of the band. But for some reason they continue to focus on the large industrial class.

And finally to go to Mr. Morrison -- Mr. Morrison alluded to this in his own argument, that some parties may not accept or may feel that what they are doing -- I think he said was patently unreasonable or something along those lines with respect to the difference in how they treat the Nuco PPA and the Genco PPA.

And again, we just have to highlight that that is what we think the case is. They have sort of picked and choosed.

They have said it is based on the PPAs, except where it isn't based on the PPAs. That's a hard one to accept as economically rational.

I believe Mr. Morrison stated that Dr. Rosenberg said that if the 1992 decision was -- wasn't in place, he would have used fixed variable. Again, I don't think that's exactly what he said. I think what he said was the 1992 decision was based on a 40/60 split in which the Board then asked NB Power to support it.

The support came in the form of the report by Reed, which did support it and supported the Peaker Credit Method. And then having seen that the Peaker Credit Method did support the Board's Order, whether or not the Board subsequently adjudicated on it, Dr. Rosenberg was willing to accept that. And when he did his own analysis and asked his own IRs, thought that the Peaker Credit appropriately modified for the capital fuel split was correct for New Brunswick. So he didn't go back to the fixed variable.

But as Mr. Knecht said, these are both traditional type of approaches. There is the fixed variable, there is the Peaker Credit -- there is a lot of others. But Dr. Rosenberg didn't have to start with the fixed variable or consider starting there, because he saw the Reed Report that did appropriately support the 40/60 split using the Peaker Credit Method. And he didn't see any reason why that was inappropriate for New Brunswick, so therefore, there was need for him to start from another base, because he felt the Peaker Credit Method was an initial base -- appropriate base to start from.

With respect to export credits, on that issue again, you know, our view is that Disco's evidence as put forward is that the export credits are merely following the Genco contract. So the Genco contract is 100 percent demand. So the export credits are 100 percent demand.

Our view is that that's not the approach that should be taken and then therefore we commend to you again, Dr. Rosenberg's approach that's more consistent with the way the exports are actually sold, the amount of capacity and energy and that was the exact same approach that Messrs. Adelberg and Garwood suggested.

And on two final points, one, Mr. Morrison in his discussion of gradualism, his statement was -- I don't have the transcript, but to paraphrase, it's particularly important in periods of high fuel prices, essentially to go slowly.

I would hesitate to say almost the adverse. It's particularly important to get your rate form right when we are in volatile fuel periods. You can't just say, oh, because the underlying fuel costs are going up, we should leave our inappropriate price signals in place, because this would cause a more drastic change. Get the price signals, get the rate forms, get the cost of service right, then use a phase in or a cap if necessary. This is the time you have to get it right.

You just don't say fuel costs are going up and so that's too expensive then it would be too hard on customers. Let's leave all the underlying things wrong, even though for example on the declining block, everybody agrees it should go. You know that makes little sense to us. And volatility is what we want to get away from. Proper pricing is what we want to get into. You can't get to that. You can't start sending better price signals that reflects actual fuel costs unless you get the rate designs correct.

And finally on the last point, Mr. Morrison indicated that he felt that Disco was the only unbiased -- I believe that was his words -- party in this proceeding and that everyone comes with a perspective.

Again, I hope that I was clear yesterday. The perspective in which EGNB came forward and Dr. Rosenberg came forward was one of cost causation. We believe that's truly unbiased. Dr. Rosenberg was not asked how quickly can we get the prices as high as we can get them. He filed something based on cost causation.

As the record is very clear, if we went to marginal cost pricing, we probably see much more expensive residential and GS II rates, which EGNB or others could compete against. But that wouldn't be a right level playing field. So that's not what we put forward. In fact, we state that that's not correct for New Brunswick at this time. So I do believe Dr. Rosenberg's evidence in your review of his cross examination should suggest that he has been unapologetic in his approach to this as one of cost causation and that there would be no bias reflected in his evidence, nor the positions put forward by EGNB in this proceeding. Although we do have views, there is no doubt about that. Thank you, Mr. Chair.

CHAIRMAN: Thanks, Mr. MacDougall. If any party wants to take Mr. MacDougall up on his challenge to find any case law that might differ from the Nova Scotia decision, why the Chair has arbitrarily ruled that you will have one week from today to get it into the Board.

I will just ask do the Commissioners have any questions here?

DR. SOLLOWS: Yes, Mr. MacDougall. One question arising from your comments just now and one I think from your comments yesterday. The more Coleson Cove was mentioned, the more confused I get. What you seem to have just argued is that the outcome of the recapitalization of the Coleson Cove plant, because of a mix-up in the fuel supply, we should look at the outcome in determining the cost allocation rather than the expectation that the integrated utility clearly had that they were going to save fuel costs by conducting this program, this recapitalization.

And my understanding is that that would lead a certain allocation of costs between customer classes. You are saying that because, for whatever reason, that outcome has not been realized, the costs that were expended should be reallocated between customer classes?

MR. MACDOUGALL: Well Commissioner, to start with, we don't have those costs. As I say, we have EGNB IR-36, which was brought up to date to -- so we don't have all of the full costs of the Coleson Cove refurbishment in there. But in doing the Peaker Credit Analysis, as I mentioned earlier, because we know it has not served the purpose for which it was expected, ie, to save fuel costs. And Mr. Hyslop indicated some of the numbers.

It would be very difficult then to say, well that plant that was built to do that should be treated in that way because it in fact has not saved any fuel costs that it was expected to do.

DR. SOLLOWS: I guess my concern that the retroactivity of that would concern me.

MR. MACDOUGALL: There is -- as I say, and the information isn't in the record one way or the other.

DR. SOLLOWS: That's fine.

MR. MACDOUGALL: Is the problem.

CHAIRMAN: Just a follow-up to that. What happens if -- and I will give the example which was used during the hearing -- where government regulations require that in fact new pollution control devices are to be put on?

MR. MACDOUGALL: Now, see again, Mr. Chair, I think that is a perfect example, and it goes directly to what Commissioner Sollows said. You, in the past, I believe on the Belledune scrubber decision, decided that pollution control devices were to be 100 percent energy.

If one wants to deviate from a Peaker Credit Method, if you have a sound economic basis and rationale for doing that, often people will say a scrubber has to be 100 percent energy related. Now the high load factor customers won't like that because of the impacts it will have.

But you did that with Belledune and that makes some rational sense. That if that's the way it should be. You know, at least there is a sound economic policy behind something like that. A lot of jurisdictions don't do that. Mr. Knecht, in the last case, actually suggested 50/50 demand energy split, not only on the fixed costs but also on the fuel costs. You know, which would then -- you know, at that time he was acting for the large industrial customers and that would have brought some of those costs down.

But there is obviously some leeway there for the Commission, you know. In certain circumstances you do have to take into account the actual circumstances.

DR. SOLLOWS: I guess that leads into the question that arises from your comments yesterday. You indicated that Dr. Rosenberg's approach would be or could be modified to differently allocate hydro resources between demand and energy.

How would this be done?

MR. MACDOUGALL: I need Dr. Rosenberg, I think, on that, Commissioner. There would be -- the approach he took was one approach. He was -- at the time he indicated that runner river doesn't fit neatly in to a breakeven analysis.

DR. SOLLOWS: Right.

MR. MACDOUGALL: I'm sure there's many ways to approach hydro and I think it would be inappropriate for me to try and reflect them.

DR. SOLLOWS: Okay.

MR. MACDOUGALL: It was a question that would have been better posed to Dr. Rosenberg, in all fairness.

DR. SOLLOWS: Thank you.

CHAIRMAN: I think Commissioner Sollows has already canvassed the one question I had, Mr. MacDougall. Thank you very much.

MR. MACDOUGALL: Thank you. And I think this is my last hurrah so thank you very much, Commissioners and Chair for bearing with me throughout the proceeding. I hope I was of some value.

CHAIRMAN: Thank you. The Irving Group I passed over. I apologize. Any summation from them.

MR. BOOKER: No comments, Mr. Chair.

CHAIRMAN: No comments. Okay, fine. How long do you anticipate your rebuttal, Mr. Morrison?

MR. MORRISON: 15, 20 minutes at most.

CHAIRMAN: Good. We will take our break.

(Recess)

CHAIRMAN: Go ahead, Mr. Morrison?

MR. MORRISON: Thank you, Mr Chairman. I don't intend to be too long, but there are a couple of things that did come out yesterday that I feel compelled to address, particularly I am going to start at the end of yesterday with Mr. Hyslop's proposed order.

If the Board is seriously considering granting that order, then I do have some comments to make with respect to --

CHAIRMAN: Well now, Mr. Morrison, I was kidding and you know that.

MR. MORRISON: I understand that, Mr. Chairman.

CHAIRMAN: It will be carefully considered like all of your arguments.

MR. MORRISON: Of course, sir. And I apologize -- I don't mean to be facetious.

I would like to take about the order. First, I guess we take the position that what Mr. Hyslop is proposing is completely unreasonable, both in terms of the work requested and the time frame he suggests within which it is to be completed. It may be that Mr. Hyslop and others don't comprehend the work that would be required to fulfil this particular order.

In particularly, if you look at 6(ii), which is the metering for stratums and classes, the analysis required for a statistically valid load research sample design, as is suggested, is significant.

First Disco would have to extract customer data from the its databases. There would be verifying and sanitizing the data. Performing statistical analysis to determine the various sample designs. Based on sample statistics, selecting the optimum design, and then reviewing and getting approval of the results. That just cannot be done by January.

CHAIRMAN: Well what are you suggesting? How long would something like that take?

MR. MORRISON: It would be at least six weeks of work. And that's assuming that we didn't have all of our resources tied up in a rate hearing.

So in any event, there is a tremendous amount of work involved in that piece alone. But he is also asking the Board to order Disco to prepare and file a new cost of service study using new classification and allocation methodologies. And we are also to include the creation of a new customer class, which -- and the removing of farms and churches.

First of all, which farms and churches would be removed? Would it be all farms excluded or just industrial-type farms? Would all churches be excluded or only those above a certain consumption level or a particular load profile?

These questions would have to be looked at and addressed. And if you remove farms and churches, you have to put them somewhere. So you would have to create a new class. And creating a new class means rejigging the entire cost of service study. There is also an education component here. You just can't pull people out of a class and say you are in a new class overnight. The other thing is we would have to send our energy advisors out in the field to actually conduct a census. Are the churches really churches? Are the farms really farms? This is all going to take some time.

Mr. MacDougall referred to the glacier the other day. Well, if there is anything that should be glacially slow in regulatory, it should be the creation of new rate classes. I am not going to throw myself in front of a glacier, but I don't think I should be jumping off a cliff either.

And finally, any change in rate structures requires the approval of Disco's Board of Directors. And that realistically cannot happen by January.

More important to this process, however, is this new cost of service study would result in new and different revenue to cost ratios and that would have implications for everyone. And it would obviously be of interest to the Intervenors. I know that we would want to have someone like Mac Ketchum review our analysis and provide expert opinion in support of it.

Surely Mr. MacDougall's client would want to review the cost of service study and file expert evidence, as I would suspect the other Intervenors. And I would anticipate there would have to be an IR process. In short, we would be into a whole new CARD hearing and the time we have spent here would have been if not wasted, certainly ill spent.

Given his timeline, and I am assuming he wants this done before the commencement of the Revenue Requirement Hearing, what we will really be doing is turing the Revenue Requirement hearing into a CARD hearing.

That may also cause some other problems. At this late date, I know that Mr. MacDougall has indicated that he and his client have no intention in participating in the Revenue Requirement. If this is going to be revisited, I am certain -- and Mr. MacDougall can speak for himself on this, that his client would want to be present. Having not anticipated being at the Revenue Requirement, I don't know what Mr. MacDougall's schedule is, but if he is already booked, I would anticipate that there may be motions for delay of the Revenue Requirement hearing. And clearly if that happens, clearly your rate decision would not be forthcoming for the implementation by April 1st.

So just so we are clear, I want to make our position, Disco's position perfectly clear. We think that the proposed order is completely unacceptable and is unreasonable at best. And that's all I am going to say about Mr. Hyslop's proposal. I would like to go to --

CHAIRMAN: Mr. Morrison, just one question I do have is that customer classification, when was the last time NB Power actually took all of its billing data and did an analysis of that data to see how the various customer classes stood and whether there are real outliers and that sort of thing?

MR. MORRISON: The last time a comprehensive analysis was done was in the late '90s. And they looked particularly at general service and small industrial.

CHAIRMAN: And was residential done at that time as well?

MR. MORRISON: No.

CHAIRMAN: So what I am saying is when was the last time a complete study of all your customer data was done? Early '70s?

MR. MORRISON: It could very well be. Mr. Larlee isn't aware at this point. Certainly not while he was in the job.

CHAIRMAN: Yes. Okay. Go ahead, sir.

MR. MORRISON: I would like to move on to the question of interruptible and I will just touch on this briefly. Mr. Hyslop did spend some time yesterday basically saying that the interruptible rate is a tremendous benefit to industrial customers.

Now the only comment I want to make about this is I want the Board to realize that it is -- you know, it is not all roses for the interruptible customers. These customers are subject to interruption. And that is something that not all customers are willing to accept the risk of. And when they do get interrupted, it is very, very expensive for those customers that are interrupted.

Also interruptible customers are exposed to fluctuations in the energy price. They take the fuel price risk, whereas Disco's other customers do not. And they get the benefit of some rate stability. So I just want to point out those two aspects of the interruptible benefit, if you will.

I do want to talk a little bit more about interruptible, because Mr. Hyslop was suggesting yesterday that interruptible prices move toward -- or move to market prices actually. And Mr. MacDougall, when he referred to the Nova Scotia case just a few minutes ago, pretty much hit the nail on the head.

Disco is a standard service provider. And it is obliged to serve in-province load. To this end, Disco has 100 percent of the heritage capacity under contract. Export benefits derived by Genco from this capacity after the in-province load is served, is shared with Disco.

Now, Mr. Hyslop has suggested that the interruptible rate be priced at market prices. If you think this through, there are some practical things that are probably going to happen.

First of all, 70 percent of that load, the interruptible load, is not tied to sell for cogenerators. If that rate moves to market prices, there is a high probability that those customers will convert their interruptible load to a firm load, because of the price signal. This will not result in increased exports because this load now firm, must be served by Disco, as in-province load.

Finally, as a result of this load going to firm, Disco's need for capacity will be advanced. In other words, the margin between resources and the load will be narrower. So there are some practical considerations that have to taken into consideration when you look at just saying, let's move interruptible rate to a market price.

I am going to move on to Mr. Gorman. And I only have one point that I want to deal with from Mr. Gorman's argument yesterday. And he was referring to the evidence of Ms. Zarnett. And you will recall that he constructed a scenario to demonstrate that the wholesale class should have a revenue to cost ratio of 1.015 instead of 1.05. And to do this he created what he called three transmission classes. Transmission, large industrial, the wholesale class and the class he called -- and I think I have it right, Disco retail.

Now, first of all, this Disco retail class is a hypothetical class. It does not exist in reality. He constructed it by taking customer classes of Disco, similar to the customer classes serviced by the municipalities.

He then took the revenue to cost ratios for these classes, the Disco classes, aggregated their revenue to cost ratios and came up with the revenue to cost ratio of 0.015. And you will recall he put that question to Mr. Larlee, and Mr. Larlee agreed with the math, not the methodology, but he did agree with the math.

So he took this Disco retail class and he compared it to the class to the other -- what he called the other transmission classes and said that they should all have the same revenue to cost ratio as this hypothetical class, which is 1.015. And I wrote down what he said. He said that the hypothetical Disco rate class and the wholesale retail customers of wholesale are essentially the same.

Now we categorically and unequivocally reject the suggestion that they are essentially the same. And we believe the analysis that -- or the comparison that he is making is fundamentally flawed.

First of all, it is a construct, as I said before. There is no Disco retail class. It is a hypothetical class. The assertion that the two classes are essentially the same is just plain -- in our view just plain wrong. This hypothetical class, the Disco retail class, first of all, is not a transmission class at all. Those customers are served off the distribution system.

Secondly, the mix of customers is completely different. Disco has a much different mix of urban rural than does wholesale, for example. The cost of the two systems are completely different. And as I mentioned earlier, they hypothetical class, the Disco retail class, is not a transmission class at all. These customers are serviced off the distribution system and therefore they have Disco's distribution costs incorporated into their rates, while the other two transmission classes do not.

So it's my submission that the comparison that Mr. Gorman was trying to make is really a meaningless comparison. I would say it's not just comparing apples and oranges. It's comparing a hypothetical apple to two oranges.

I do have a couple of comments coming from -- actually just two coming from Mr. MacDougall's argument. The first deals with the standby rate that he was proposing. And we don't have much to say about the standby rate, other than to say that currently the economics of cogeneration, what with gas prices and what have you, have not resulted in a need for a standby rate similar to that one being proposed by EGNB. There simply hasn't been any customer interest or demand to Disco at this point.

Disco has no fundamental disagreement to a standby rate for cogenerators and we can make that clear. However, designing such a rate may not be as simple as may have been characterized yesterday.

And to put it succinctly, Disco has no problem providing a standby rate to back up a cogenerator. But it really would not want to get into the business of providing a rate that would back up a merchant generator. If a merchant generator is set up and was looking for a standby rate, we don't want to get into that business.

DR. SOLLOWS: Would you not be able to address that by applying the backup or the standby rate only at distribution level generators?

MR. MORRISON: That would be one way to do it. But it is possible, as I understand from Mr. Larlee, it is conceivable to have a merchant generator embedded in the distribution system.

I am not saying it is impossible to do, but there would have to be some thought put into the rate design for that standby rate to eliminate those possibilities. And that's the only point I want to make.

First, we don't object. Secondly, there hasn't been any human cry for the service for that particular product. And we just would have to exercise some care in designing the product.

This comes -- the next point I want to make wasn't a point that Mr. MacDougall addressed directly in his argument but it was one that came up as a result of a question from the Chairman.

And I think the Chairman asked Mr. MacDougall whether it was because of the way the Genco PPA is priced, could seasonal rates be implemented using the PPA causation approach. I might be paraphrasing there but I believe that is the thrust of the question.

We believe the simple answer to that is yes. There is nothing in the Genco PPA which prevents Genco from billing Disco on a monthly basis for the fuel costs incurred to service Disco's load. And should the Board rule that Disco include seasonality in its cost allocation study, Disco has the ability through its right of auditing under the Genco PPA to include monthly fuel costs in a modified study.

Those are all the comments I have, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Morrison.

DR. SOLLOWS: Yes, thank you, Mr. Chairman.

MR. MORRISON: This is my favorite part, by the way.

DR. SOLLOWS: I have only one question arising from what you said earlier today, and then a few -- I think two or three perhaps from what you had argued yesterday.

You made reference to you were concerned about the time table for conducting a load -- an analysis of billing data and sort of tying that in or make that the precursor for a load research program. And certainly I would appreciate that if you want to do it correctly, you are going to require time. You made one comment about sanitizing the data. And that's something that I would like you just for the record to define.

MR. MORRISON: As I understand it, and you will recall the IR with respect to the -- I don't know how many million pieces of customer data -- as Mr. Larlee explained to me, when they were going through that there would be some data that looks very odd and would have to be excluded because for anomalies. Also depending on the data -- well in this case, we wouldn't have to worry about confidentiality, but I believe it's just going through the data and removing anomalies.

DR. SOLLOWS: Thank you. That's what I thought you meant. But I did anticipate --

MR. MORRISON: I know it does sound like a loaded term, but --

DR. SOLLOWS: Referring to your argument yesterday, you argued that -- and I think -- I can't recall, someone had touched on this point, but the current relatively high fuel prices work against rapid elimination of the declining block rate. I would have thought that an environment of rapidly escalating heating costs for non-electric customers, which I think are about 40 percent of the customers of -- residential customers in the market, would provide you an opportunity to make larger adjustments, not make them more slowly.

MR. MORRISON: I believe the concern dealt largely with rate impacts. If -- and you are talking about seasonality?

DR. SOLLOWS: No, I am not talking about seasonality. What I am suggesting is that the rate of escalation of fuel costs creates a context where non-electric heat customers are paying perhaps 20, 30, 40 percent more for their space heating.

Why would not that create an opportunity for you to make similar adjustments for space heating customers, because it creates a context in which everyone in the province is being treated more or less equitably, not that anyone really wants to see a 40 percent rate increase, but --

MR. MORRISON: I guess that's one way to look at it. And we -- I think we can see the logic of your approach. I guess it's really just a customer impact when other fuel prices are going up and customers are hit with yet another what could be a significant increase. It's just a rate impact issue.

And again that's -- as I think I mentioned in some cross examination of Dr. Rosenberg, there really is a balancing act for you to determine the balance, the correct balance between customer impacts and price signalling.

DR. SOLLOWS: Yes. Thank you. You also argued that marginal cost studies were applicable for functional unbundling, but probably not applicable after functional unbundling or less useful after functional unbundling. My understanding of that is that the marginal cost studies would be less useful after you have market prices available. And really it's irrespective of whether there is functional unbundling or not. The question is whether or not there are market prices available that make the marginal cost studies redundant, is that fair?

MR. MORRISON: I would agree with you on that point, but there is also the point -- I think the point I was trying to make, Commissioner Sollows, was this. Once you have a stand alone distribution entity, unbundled entity, it no longer has access to the generation resource data upon which a marginal cost study is based. So it's really an access to date question.

DR. SOLLOWS: Thank you. And finally -- and I think I am trying to -- I can't recall who mentioned it, but I want to address this point as well. You argued that Disco, alone amongst the participants in this hearing, can be relied upon to provide advice that is impartial as between customer classes.

The question that arises in my mind is, doesn't Disco's self-interest in revenue stability suggest that it may bias its decisions in favour of retaining customers that it might otherwise lose, either to other fuels or to the competitive market or an alternative market at the transmission level?

MR. MORRISON: I believe that came up in cross examination of Mr. Ketchum about retention of the declining -- sorry, retention of the declining block, yes -- did lead to stability -- give Disco a certain margin of price stability.

I can't recall the response exactly, but I believe the response was -- in the course of the discussion was -- that's an outcome, but it's not something that they considered in looking at the cost of service study.

It is certainly a reality. But I believe the evidence from our panel was that that didn't influence them in terms of their analysis.

DR. SOLLOWS: Thank you.

CHAIRMAN: Just one question, Mr. Morrison, and it's a hypothetical, legal. This will become your most favorite part of the hearing after this.

Is it within the Board's jurisdiction to say in its ruling in reference to the CARD and to the hearing that we consider a standby rate to be a plus and we direct Disco to go away for eight months and study it and file with us a proposed rate with backup information on same and serve notice upon the parties to this proceeding so that they may have input to the Board as well before there is a final ruling made on it, something like that?

MR. MORRISON: I did give that some thought. Although I did not have the luxury of time to do any research on the point, Mr. Chairman. And this came up I think at some point in the pre-hearing process as well. And that relates to Mr. Hyslop's question yesterday about the granting of -- issuing of ancillary orders, I believe or something that will reach beyond the conclusion of this particular hearing.

Quite frankly, I don't know the answer to the question. I know that with respect to transmission, for example, the Board has an ongoing regulatory oversight function. That function doesn't appear to be specifically stated in the legislation with respect to Disco.

So I guess the question becomes that once you issue a final order at the conclusion of the Revenue Requirement, are you then functus and can you then -- can anything you do go beyond -- reach beyond the conclusion of a rate case, because your jurisdiction only applies when Disco applies for a rate increase?

Quite frankly, I don't know the answer to your question from a strictly legal point of view. My best judgment at this juncture is that you probably can, but -- and as you know, I believe Disco has also already undertaken to participate in a CARD hearing next year as directed. So certainly we are not resistant, but I can't give you a definitive answer on your authority.

CHAIRMAN: That's not a CARD hearing that you are committed to. It's the Load Forecast.

MR. MORRISON: Sorry.

CHAIRMAN: Yes. No, I don't want you to hang yourself --

MR. MORRISON: Sorry. No. Sorry. Long-term Load Forecast hearing, that's correct. We have agreed to do that. And I am sure you will see co-operation on an ongoing basis.

CHAIRMAN: Yes.

MR. MORRISON: My gut feeling is that you probably do have the authority, but I haven't researched the point.

CHAIRMAN: Thank you very much. I -- we probably will give parties the opportunity at the time of the Rate Hearing itself to address that with appropriate lead time on it, because, you know, we are caught in a bind where we want to be just and reasonable in the decision. And if we know that something is very desirable to have happen now on the basis of the evidence, but it requires more work on your part, we want to be in a position to give you sufficient reasonable time to collect the data or do the analysis or whatever, before you then come back with a final -- this is our best take of it and go from there.

I just think it makes for better regulatory regime, period.

MR. MORRISON: I think our client -- my client is anticipating that there will be some ongoing research responsibility with the caveat, of course, that I mentioned yesterday that you have to be mindful of the resources and the cost benefit of certain research projects.

I think that everybody agrees that further study -- and we made it perfectly clear through the evidence that for the load research is a desirable thing.

CHAIRMAN: Good. Thanks, Mr. Morrison. Any final matters at all? Okay. Again, I want to thank all the parties for their cooperation. And I have used quite an epitaph to describe our pre-hearing conference in this matter. But it seems to have gone on forever. However, your co-operation and professional conduct throughout is greatly appreciated by the Board and it has made our work a lot easier.

And as I indicated to the press yesterday, we will try and have our decision -- our ruling is what you got to call it I guess, in reference to the CARD end of this, out before the commencement of the Rate Hearing, as soon as we reasonably can possibly do so.

So again I thank you all. I want to thank the interpreters, who sat back there interpreting like crazy with very little response by way of listening to what they have to say. And I will go no further on that, except we appreciate your good humour. And the shorthand reporting services as well, and not only she who is in the room constantly, but those who type that transcript and get it to all the parties in jig time. And to Board Staff, of course. So thank you very much.   And we will see you perhaps on Motions Day.

And thank you, Mr. MacDougall, for your participation in particular. We hope we won't see you too soon in this particular role again.

(Adjourned)

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

Reporter