

ONTARIO ENERGY BOARD

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| FILE NO.: | EB‑2014-0055 |  |
| VOLUME:  DATE:  BEFORE: | 1  October 20, 2014  Ken Quesnelle  Allison Duff | Presiding Member  Member |

**EB-2014-0055**

THE ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

**AND IN THE MATTER OF** an application by Horizon Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 and for each following year through to December 31, 2019.

Hearing held at 2300 Yonge Street,

25th Floor, Toronto, Ontario,

on Monday, October 20th, 2014,

commencing at 9:36 a.m.

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VOLUME 1

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BEFORE:

KEN QUESNELLE Presiding Member

ALLISON DUFF Member

LJUBA DJURDJEVIC Board Counsel

SURESH ADVANI Board Staff

ANDREW TAYLOR Algoma Power Inc.

SCOTT HAWKES

TIM HARMER Algoma Coalition

RANDY AIKEN Energy Probe Research Foundation

DAVID MacINTOSH

MICHAEL JANIGAN Vulnerable Energy Consumers Coalition (VECC)

ALSO PRESENT:

GLEN KING Algoma Power Inc.

TIM LAVOIE

DOUG BRADBURY

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Monday, October 20, 2014

### --- On commencing at 9:36 a.m.

MR. QUESNELLE: Good morning. Please be seated.

The Board sits today on the matter of an application by Algoma Power Incorporated. Algoma Power filed a complete cost-of-service application with the Ontario Energy Board on May 12th, 2014 under section 78 of the Ontario Energy Board Act, seeking approval for changes to the rates that Algoma Power charges for electricity distribution, to be effective January 1st, 2015. The Board assigned the application File No. EB-2014-0055.

The Board established procedures to facilitate a technical conference, which was held on August 20th, 2014, and a settlement conference, which commenced on September 29th, 2014. The parties' settlement discussions concluded on October 8th, 2014.

Algoma Power filed a proposed partial settlement agreement between itself and the registered intervenors -- collectively the parties -- on October 10th, 2014. The following issues remain unsettled: Algoma Power's proposal to seek recovery of the RRRP funding variance from 2002 to 2007 period, the appropriate revenue-to-cost ratios, and the appropriate fixed/variable ratio.

Today we'll hear any additional submissions related to the proposed settlement agreement, as well as evidence pertaining to the unsettled issues.

My name is Ken Quesnelle, and I'll be presiding over today's proceeding, and joining me on the panel is Board member Allison Duff.

I will now take appearances.

# Appearances:

MR. TAYLOR: My name is Andrew Taylor. I'm counsel for Algoma Power

MR. QUESNELLE: Good morning, Mr. Taylor.

MR. JANIGAN: Mr. Chair, Michael Janigan for the Vulnerable Energy Consumers' Coalition.

MR. QUESNELLE: Good morning, Mr. Janigan.

MR. AIKEN: Good morning, panel. Randy Aiken on behalf of Energy Probe Research Foundation. With me is David MacIntosh.

MR. QUESNELLE: Good morning, Mr. Aiken.

MR. HARMER: Tim Harmer. I'm with Algoma Coalition.

MR. QUESNELLE: Perhaps you will repeat that with the mic on.

MR. HARMER: Thanks. Tim Harmer. I'm here with Algoma Coalition.

MR. QUESNELLE: Good morning, Mr. Harmer.

MR. KING: Glen King, CFO, Algoma Power.

MR. LAVOIE: Good morning, Tim Lavoie, regional manager for Algoma Power.

MR. BRADBURY: Doug Bradbury, director of regulatory affairs, Algoma Power.

MR. QUESNELLE: Okay, thank you very much.

MS. DJURDJEVIC: Ljuba Djurdjevic, counsel for Board Staff, and with me on behalf of Board Staff is Suresh Advani.

MR. QUESNELLE: Thank you very much.

So as I stated in the opening remarks, we have one issue to deal with -- well, we'll deal with the settlement agreement first.

The other thing I just wanted to mention at the outset, Mr. Taylor, is the schedule for submissions afterwards. I understand that you'd be prepared to provide argument in-chief orally once we've concluded on the oral section of the hearing today or tomorrow?

MR. TAYLOR: I am prepared to make oral argument on the issue of the RRRP variance. I'm not prepared to make oral argument on the rate design issues.

MR. QUESNELLE: Okay. So we'll need to establish a schedule then to accommodate that, and I will just mention that now so that the parties can discuss that over the course of the day and perhaps make a proposal to the panel when we conclude on the production of evidence over today and tomorrow. Okay? Great. Thank you.

# Settlement Proposal

So turning to the matter of the settlement proposal, there was a submission filed by Board Staff on Friday. That is, in particular, we would like to hear comments on that from Board Staff and the applicant, and anything else, Mr. Taylor, that you want to provide the Board as far as additional comments or submissions with relation to the submitted proposal -- settlement proposal. So perhaps you could go first.

MR. TAYLOR: I think I'd agreed with Board counsel that Board counsel or Board Staff would present the settlement proposal, and we're available to answer any questions that the panel may have.

MS. DJURDJEVIC: Thank you, panel. Well, we were -- Staff was not prepared to go through the settlement proposal section by section. The Panel has had an opportunity to review it, and if any questions arise, those questions are properly responded to by the applicant and intervenors, since they are parties to the settlement, whereas Staff is not.

Staff's submission, generally, is in support of the proposed settlement on the issues set out in that -- in that settlement -- proposed settlement agreement, and we don't have any further comments unless the panel has questions or parties have any reply comments.

MR. QUESNELLE: Well, I would ask Mr. Taylor then to respond to what the Staff put in writing and any comments on a go-forward basis on the issue with relation to the costs that have been agreed to for the computer hardware and software to be recovered, and the options presented as far as how that would be dealt with on a go-forward basis.

MR. TAYLOR: Sure. It's my understanding from having read Board Staff's submission that Board Staff's recommendation was that we modify the accounting of those costs on a go-forward basis. And I understand that Board Staff seems to be fine with leaving the methodology the way the applicant had proposed it in its application for now. Is that correct, Board Staff?

MS. DJURDJEVIC: Yes, that's right.

MR. TAYLOR: And Algoma Power agrees to do that on a go-forward basis, so at its next rate application it will present this information using one of the two options that was put forward by Board Staff.

MR. QUESNELLE: As I read it -- and I'll ask for clarification on this -- as it stands now, there is money collected as part of the revenue requirement for these costs, but is -- how is the cost incurred? And what I'm specifically -- the revenues that are collected, what happens to those revenues at this point, as far as the payment for services received, and what is the intention for the year 2015?

MR. TAYLOR: I'd like to turn that question over to the panel.

MR. QUESNELLE: Certainly.

MR. KING: Thank you.

MR. QUESNELLE: Now, we're at a point now where we're still dealing with the settlement, Mr. Taylor. Would you like this panel to be sworn, and then we'll carry right on into the -- afterwards into the new -- the unsettled issues, rather?

MR. TAYLOR: We may as well do it, since we are going to have to do it anyways.

MR. QUESNELLE: Yeah, okay. Let's do that then.

MS. DUFF: You can remain seated.

# ALGOMA POWER INC. - PANEL 1

**Glen King, Affirmed**

**Tim Lavoie, Affirmed**

**Doug Bradbury, Affirmed**

MR. QUESNELLE: Okay, Mr. King, perhaps you could respond to the issue on the matters raised by Board Staff.

# Presentation of the Settlement Agreement by Mr. King:

MR. KING: Okay, so as Mr. Taylor has noted, we've reviewed the options that were provided by Board Staff, and, you know, as we've mentioned in evidence and through oral hearing and settlement, you know, in prior years this is the methodology we've consistently used, so basically the methodology we came back with in 2006 when we presented the panel through Algoma Power and some of our other subsidiaries is consistent. We have assets that we share amongst our companies, and those assets, you know, in particular IT services, so for rate-making purposes we allocate those assets amongst the companies.

When we looked at it, we had talked to Hydro One, and we had talked to other, you know, other groups, and we thought it was fair and it was transparent, and this is what we've consistently done.

However, you know, we understand the Board's point of view and we appreciate that. And so on a go-forward basis starting in 2015, we will use a CIAC method of moving assets between companies, sharing assets between companies.

To your question, and with respect to revenues, our revenues, so the revenues are collected by Algoma Power through the revenue requirement. For financial reporting purposes, we actually have charges back and forth.

Now, obviously for ratemaking purposes we share the assets, but for financial reporting services, so Canadian Niagara Power would charge Algoma Power basically the depreciation of the cost of capital associated with those assets. And Algoma Power would pay Canadian Niagara Power for those services. So there is a transfer of money between the companies that happen for financial reporting purposes.

MR. QUESNELLE: And the change would then bring it into the affiliate transaction, which would be different?

MR. KING: So, as Board has suggested, they've -- instead of simply for ratemaking purposes to share the assets, so on a go-forward base, Algoma Power would make capital contributions to Canadian Niagara Power based on their share of ownership or their share of usage of those assets. So they'd make a capital contribution and set it up as a CIAC and accounts payable to Canadian Niagara Power.

So that would be the go-forward methodology for doing that.

MR. QUESNELLE: When we say go-forward, are we talking about in -- starting January 1, 2015?

MR. KING: It will take us -- there is some SAP configuration required for that, but effective January 1, '15, it will happen on that date. Some time in '15, retroactive to that date.

MR. QUESNELLE: I guess my point -- it is not that your next cost of service application would be as a result of this one, and go into effect?

MR. KING: Absolutely.

MR. QUESNELLE: Thank you very much.

Ms. Duff, any questions on that?

Okay. Unless you have anything else, Mr. Taylor, on the settlement, we'd -- the only other question, and -- would be as a result of any findings that the Board will make on the unsettled issues, is there anything within the settlement agreement that is subject to change?

MR. TAYLOR: No, there isn't.

# Questions by the Board:

MR. QUESNELLE: Okay. The one question that we did have -- and we are going to reserve on this until it plays out, so -- until we hear the evidence on the unsettled issues, so it might become more clear, but there was a question around the funding elements in the -- in that one of the unsettled issues is the split between the fixed and the variable, and we have a table in the settlement agreement that spells out the result of the settlement.

Is that -- is there anything at play there in the -- and perhaps we'll have a better understanding about it once we hear exactly what the issues are within the unsettled issues, but is there anything subject to change on that?

MR. TAYLOR: I think that depending on the outcome of that issue, that table could change. Am I right about that, Doug?

MS. DUFF: It is table number 11.

MR. BRADBURY: Yes, depending on whether or not there are changes made to the fixed/variable splits or the revenue-to-cost ratios themselves, it may impact the total bill impacts, and cause reason or requirement for rate mitigation.

MR. QUESNELLE: Okay. Thank you very much. And with that, perhaps we could go into the unsettled issues, then, Mr. Taylor. Okay?

# Examination-In-Chief by Mr. Taylor:

MR. TAYLOR: Okay. Panel, why don't we start off with all of you have introducing you are yourselves and telling the Panel your role at the company?

MR. BRADBURY: Again, my name is Doug Bradbury. I'm the director of regulatory affairs for Algoma.

My primary role amongst the issues that we're discussing today, I handle all matters dealing with cost allocation and rate design. And that's the issues I will be addressing today, and any questions you have.

MR. LAVOIE: Tim Lavoie, regional manager, Algoma Power.

I'm dealing with the issue of the RRRP variance issue, and I bring some relevance to that issue based on my history with both Great Lakes Power Limited and now with Algoma Power. I was involved with the implementation of the original RRRP regime and subsequent to that, so...

MR. KING: As I mentioned, Glen King, CFO of Algoma Power.

I am here sort of to provide support and some oversight of Doug and Tim through the process.

MR. TAYLOR: I'm going to start with some examination-in-chief, and I'm going to direct my examination to you, Mr. Lavoie.

When did you start working at Great Lakes Power, the predecessor to API?

MR. LAVOIE: September 1993, I started with the company. And I worked in a number of roles early on in my careers. Started within the finance department in the mid- to late '90s, and then became customer and finance manager through the period of market opening and deregulation, with Great Lakes Power Limited.

MR. TAYLOR: So between the years 2002 and 2007, were you involved in any way whatsoever with the RRRP, or rate design related to RRRP?

MR. LAVOIE: Yes, certainly was directly involved with all the regulatory proceedings, rate applications during that -- and initial market opening, as well as through the time period 2003 to 2007, in particular during the time when the RRRP funding mechanism was put in place through regulation with the Ministry of Energy and then subsequent, through a rate order.

MR. TAYLOR: So do you have firsthand knowledge of how the RRRP funding mechanism came to be within GLPL?

MR. LAVOIE: Yes.

MR. TAYLOR: And what kind of relief is Algoma Power seeking in regard to the RRRP funding here today?

MR. LAVOIE: This relief is dealing with a variance as a result of the mechanical nature of the way the funding was calculated and applied to customers during that timeframe, which is very similar to the mechanism that works through the Hydro One system legacy customers that also achieve -– or receive a monthly subsidiary to customers in their low-density system.

MR. TAYLOR: So the relief that you are seeking in this proceeding, are you looking for some sort of rate order from the Board allowing you to recover money from your customers?

MR. LAVOIE: No, we're not -- I don't believe we're asking for any rate order. This is simply a true-up on an amount that, again, by a mechanism of applying the subsidiary to the customers, was held in an account similar to what we've seen with Hydro One in their application of this subsidy.

MR. TAYLOR: So is what you're seeking from the Board confirmation of entitlement of amount of compensation?

MR. LAVOIE: That's correct.

MR. TAYLOR: Why do you need confirmation from the Board to recover this compensation?

MR. LAVOIE: Well, interestingly, we -– our initial thoughts on the matter were simply to correspond with Hydro One to true up this account, which, again, we thought was very mechanical in nature.

Hydro One had a different opinion, in terms of they believed that we did need some confirmation from the Board and some direction from the Board on the matter.

MR. TAYLOR: When you refer to "this account," are you talking about an account that you have?

MR. LAVOIE: Certainly we have an amount held in a receivable account, yes.

MR. TAYLOR: A receivable? Okay. And so you collect from Hydro One?

MR. LAVOIE: Hydro One has, I believe, the authority under the Regulation 44201, to hold -- to disburse amounts that are -- I guess it's a twofold account.

It, on the one hand, receives money from the IESO to fund the RRRP requirements in the province, and at the same time it issues amounts out of that funded account to both Hydro One legacy, Hydro One remotes, Algoma Power, and I believe there are a few other parties.

MR. TAYLOR: So would I be correct in describing the situation as follows? From 2002 to 2007, your customers received a subsidized rate, and because of that subsidized rate you weren't recovering your full revenue requirement from customers, and therefore you were compensated by Hydro One for the deficiency? Is that how it worked?

MR. LAVOIE: Yeah, the mechanism was such that -- if you refer to -- there is the rate order. EB-2003-0149 talks about the subsidy -- or the Algoma Power rate schedule rates are -- and that's included in our evidence. Just for reference, it is Exhibit 9, tab 8, schedule 1, appendix A.

MR. TAYLOR: Does everyone have a copy of the compendium that was provided by Energy Probe? Panel, do you have that?

MR. QUESNELLE: We do, and if we're going to refer to it, we'll give it an exhibit number now.

MS. DJURDJEVIC: That will be Exhibit K1.1.

EXHIBIT NO. K1.1: ENERGY PROBE COMPENDIUM.

MR. TAYLOR: Because the rate order that you are referring to I believe is at page 15 of 23 of this compendium.

MR. LAVOIE: Yeah, it goes on to page 17 of 23, which is what I was referring to.

MR. TAYLOR: So what were you referring to on page 17?

MR. LAVOIE: There is a note at the bottom of the rate schedule which talks about the regulations, Ontario regulations, and the subsidy for year-round residential customers eligible to receive rural and remote rate protection, and it says:

"The distribution charges already reflect the appropriate discount of 28.50 per month under this program."

MR. TAYLOR: Okay. So should I take that to mean that GLPL's customers were receiving a $28.50 per month subsidy built into these rates?

MR. LAVOIE: That's correct.

MR. TAYLOR: Okay. And the $28.50 subsidy, was that unique to you?

MR. LAVOIE: No, and I believe Hydro One -- I don't believe the amount has changed in the most current rate schedule for Hydro One I reviewed yesterday. It does have a footnote similar that there is a $28.50 per month credit that is built into their rate schedule. It is almost identical to this.

MR. TAYLOR: I have a copy printout from Hydro One's website if the panel wants it or if the parties want it, and in that printout it refers to $28.50 subsidy provided to their low-density customers, so if the panel would like it I would be happy to give it to you.

MR. QUESNELLE: If you'd like to us rely on it. Sure.

MR. TAYLOR: Okay.

MS. DJURDJEVIC: We can make that Exhibit K1. -- oh, sorry, no, K1.2. The Energy Probe compendium, I don't know if I referred to it as K1.1 or 1.2, but it will be K1.1, and then this printout from the website will be K1.2.

EXHIBIT NO. K1.2: PRINTOUT FROM HYDRO ONE'S WEBSITE.

MR. QUESNELLE: Okay. Thank you.

MR. TAYLOR: Okay, so we've got this $28.50 per month subsidy that is provided to your customers and to Hydro One's low-density customers as well.

And if you turn to page 15 of 23 of Energy Probe's compendium, you will see in the first -- at the end of the first paragraph the last sentence says:

"The amended rate schedule is based on a total revenue requirement of 9.8 million, including rural and remote rate protection of $2.38 million."

Did -- I just want to understand, how did this come to be? Did the Board decide on $2.3 million in compensation that was required to you, and then from that divide that by the number of customers and the number of months in a year to come up with $28.50, or was the starting point a $28.50 per customer per month subsidiary, and then that number would be multiplied by the number of customers that you had, multiplied by the number of months in a year, to figure out how much compensation you would be entitled to during the year?

MR. LAVOIE: It was the $28.50 multiplied through the number of customers and months, in order to estimate what that annual amount would be.

MR. TAYLOR: Okay. And so this $2.3 million that's referred to in the first paragraph of the rate order on page 15 of 23, did you use this number here in order to recover compensation from Hydro One?

MR. LAVOIE: Again, because the funding of the amounts to utilities like Algoma -- Great Lakes Power at the time, Algoma Power, is from the Hydro One account, it had been then and has been now put forward as a payment on a monthly basis to Great Lakes Power at the time, Algoma Power now, on a -- based on that estimated amount, certainly through the 2003 to 2007 time line.

MR. TAYLOR: So would you be paid annually, monthly?

MR. LAVOIE: Monthly amounts.

MR. TAYLOR: Okay. So then was Hydro One paying you $2.3 million divided by 12 per month?

MR. LAVOIE: Yes, that's correct.

MR. TAYLOR: Okay, and so based on those payments the reason why we're here is because you're -- the amount that you were paid was insufficient to cover the amount that you actually subsidized your customers' rates; is that correct?

MR. LAVOIE: Correct.

MR. TAYLOR: Okay, and how much were you -- how much short were you on your compensation?

MR. LAVOIE: Over that time frame, 173,000. That exact amount is within our -- actually, it's in page 19 of 23, $173,534.

MR. TAYLOR: Okay, sorry, what's the reference to that, that --

MR. LAVOIE: Sorry. Page 19 of 23 in the compendium.

MR. TAYLOR: Okay. And this page 19 of 23, this was prepared by the applicant?

MR. LAVOIE: This was a response to an interrogatory question -- sorry, I think a technical conference question.

MR. TAYLOR: Okay, and I see there are two boxes. The box on the left has a column on the right side, "variance", and the number at the bottom of that column is 173,534.

MR. LAVOIE: Correct.

MR. TAYLOR: So this is the amount that you are seeking the Board to confirm that you are entitled to, and then you'll -- once the Board does that, Hydro One will be in a position to provide you with that amount?

MR. LAVOIE: That's the correspondence that we had with Hydro One, is -- that was what we're looking to provide.

MR. TAYLOR: And will Hydro One provide you with this amount in the absence of some sort of confirmation from the Board?

MR. LAVOIE: No.

MR. TAYLOR: Have you tried to recover that amount from Hydro One?

MR. LAVOIE: We haven't submitted an invoice, but we certainly have expressed to them that this amount is due to us.

MR. TAYLOR: So Hydro One isn't paying up until they see that the Board is on-board with this amount?

MR. LAVOIE: That's our understanding, yes.

MR. TAYLOR: Okay. Sorry, I've just lost my train of thought. If I could just have a minute.

Okay. Could we go back to page 15 of Energy Probe's compendium. And this rate order that was issued in 2003 -- and this is for rates to be made effective May 1st, 2002 -- that's what it says at the top of page 17 of 23.

There is a reference to a $9.8 million revenue requirement in the first paragraph on page 15. So that was the revenue requirement of Great Lakes Power, $9.8 million?

MR. LAVOIE: Correct.

MR. TAYLOR: Okay, now, we received an interrogatory from Board Staff that made reference to a case that had gone forward -- I think it was a motion to review, and then there was an appeal to the Divisional Court -- regarding this $9.8 million, and I think it would be helpful for the panel to understand that there is a little bit of history behind that $9.8 million, being that -- did the $9.8 million revenue requirement, did it include GLPL's –-I'm sorry, "GLPL" is Great Lakes Power. I didn't say that earlier. But did that include a return on equity for GLPL?

MR. LAVOIE: No, it did not.

MR. TAYLOR: And why did it not?

MR. LAVOIE: As part of unbundling the utility -- so Great Lakes Power Limited was an integrated utility prior to market opening, so there was an unbundling of the company into a generation, transmission and distribution business -- there was a recognition as part of that unbundling exercise that an internal subsidization that had been occurring within the utility for a number of years was no longer going to support the distribution business.

And as part of discussions with Board Staff and unbundling the distribution business in a way -- and again, I guess maybe for history as well, this was prior to any implementation of RRRP. There was a significant rate shock to the customers of Great Lakes Power Limited at the time, and as part of a mitigation on behalf of the company to those -- that rate shock, a mitigation plan was implemented.

And the start point of that mitigation plan was a zero return on equity for the distribution business, and that mitigation plan was put forth to -- as part of our initial application to the Board for distribution rates.

MR. TAYLOR: Can I stop you there? So just so the Panel's clear, you were talking about a subsidy. Great Lakes Power, they were involved in transmission, distribution and generation; is that right?

MR. LAVOIE: Correct.

MR. TAYLOR: So the distribution customers were being subsidized by transmission and generation?

MR. LAVOIE: Yes, it's -- I'm trying to keep the discussion simple on this point, is that you can imagine that the rate structure and allocation of an integrated utility is very different than a distribution utility as a standalone basis.

So there was an internal rate design and structure of rates that provided lower rates to distribution customers at -- prior to market opening than what the distribution business on a standalone basis could support with those rates. And so there was, on an aggregate utility, integrated utility basis, there wasn't a need to have distribution stand on its own, and therefore between rate design and cost of power, a way of allocating costs such that the distribution rates were at a lower level and an integrated basis than they were on a standalone.

I don't know if I complicated that.

MR. TAYLOR: No, that's helpful, because then what happens is unbundling comes along, and essentially the distribution part of the business had to operate as a standalone business?

MR. LAVOIE: Correct.

MR. TAYLOR: And as a result of that, would I be correct in saying that the subsidiaries or the rate design that you originally had in place to assist the distribution customers could not continue?

MR. LAVOIE: Correct.

MR. TAYLOR: So as I understood your testimony before, you said you proposed a rate mitigation plan, and this would have been in your very first application after unbundling?

MR. LAVOIE: Correct.

MR. TAYLOR: And the rate mitigation plan proposed -- or your application proposed that in your first year, there would be zero return on equity?

MR. LAVOIE: Correct.

MR. TAYLOR: And as part of that plan, as I remember it -- and I was counsel at the time, so that's why I say I remember it -- in year 1 there was zero return on equity. In year 2 you phased in 50 percent of your return on equity. In year 3 you phased in 100 percent of your return on equity. And then in years 4 and 5 you proposed that you would recover the deferred return on equity from years 1 and year 2? And -- no, years 1 and 2.

MR. LAVOIE: That's my recollection of it as well, yes.

MR. TAYLOR: So you filed this application, and based on that mitigation plan, in year 1 there would have been a $9.8 million revenue requirement, which included no return on equity?

MR. LAVOIE: Correct.

MR. TAYLOR: And the rates were made interim? Did that happen?

MR. LAVOIE: Yes.

MR. TAYLOR: And then those rates -- what happened to those rates as a result of Bill 210, which came out in December of 2002?

MR. LAVOIE: Those rates and the 9.8 million were frozen as part of Bill 210.

MR. TAYLOR: So basically they became -- your interim rate order became a final rate order; is that correct?

MR. LAVOIE: Right.

MR. TAYLOR: Okay. So what you are requesting now, the confirmation of the 173 -- approximately $173,000, does that in any way impact the $9.8 million revenue requirement that the Board approved in this rate order?

MR. LAVOIE: Not at all, no.

MR. TAYLOR: Why is that?

MR. LAVOIE: The 9.8 million includes the subsidy estimation of 2.3 million. And it's not above any amounts -- so it's not part of that mitigation plan or any part of the revenue requirement calculation.

MR. TAYLOR: Okay. Now, the subsequent court proceedings where Great Lakes Power attempted to recover the deferred return on equity that it's been recording, that -- that legal proceeding would have had an impact on the $9.8 million revenue requirement, wouldn't it?

MR. LAVOIE: Yes. It certainly would have had an impact, and if had been fully recovered, would have resulted in the utility earning more than the 9.8 million in all of these years that we're talking about.

MR. TAYLOR: So that legal proceeding would have impacted the $9.8 million revenue requirement that had been decided upon back in 2003, whereas -- I know I'm repeating this -- whereas what you're asking for now, the confirmation you're seeking now, would not affect the $9.8 million revenue requirement; correct?

MR. LAVOIE: That's correct.

MR. TAYLOR: Okay. I think that might be all of my questions for now.

Is there anything that you want to add, Mr. Lavoie?

MR. LAVOIE: I am just wondering if there's any benefit to talking a little bit how the $28.50 was implemented with respect to the combination with the fixed rate, in order to understand the variances a little bit, but that could come out in --

MR. TAYLOR: Sure. You know, I expect that our friends are going to cross-examine you on that issue, but if you want to give an overview beforehand, that's fine.

MR. LAVOIE: So I guess the mechanical nature of the $28.50 per customer, as it's shown on the schedule, page 17 of 23, where I talked about the rate of 19.97, which is the residential fixed monthly service charge, is already discounted by the $28.50 per month.

So mechanically we implemented the rates -- I called it -- in tandem with the fixed rate. So if we were to look at how you would subsidize the customer, you would do it on a per-customer basis and implement it in the billing system, similar to the fixed rate that we charge customers.

So when a customer would sign up at Algoma Power or at Great Lakes Power, they would be entered into the system, and the rate of $19.97 would be ultimately charged to the end-customer and a $28.50 receivable would be recorded against the RRRP account.

So the significance of that, of course, is the $28.50 inherently varies with both the number of customers, and as we've described it in the evidence, how you prorate the fixed charge over a month.

And all utilities have had to come up with a convention on prorating fixed charges, if you do not have a billing system that bills on a calendar month, that being the first day and last day of the month.

Algoma Power -- Great Lakes Power at the time -- had a bimonthly billing system, so approximately a 60-day cycle for customers. And we also had a manual meter reading system, so we would actually have to have folks that went out over the 14,000 square kilometre we have and read meters.

So I imagine that there would be very few times that we would ever have a 60-day cycle for a customer; we always got as close as we possibly could.

So in order to bill someone on the cycle for kilowatt-hour reads, you needed to develop: How do I apportion the fixed rates over that same billing period? And we established -- similar to other utilities -- that a 30-day month was the convention that we would use to apportion the fixed charges, that being the 19.97.

And then by virtue of the mechanics involved, the $28.50 credit or receivable to Hydro One was also calculated on the same basis.

So it's those two variances that we're talking about here today, as both the number of customers varied by month -- or, sorry, varied over the time frame, so if we look at page 19 of 23, it shows that variance table.

So the customer count -- so the right-hand side of the table breaks the variance into two pieces. One is the customer count variance on the far right-hand side of the table, so you can see the number of customers changed slightly over -- year over year, and the left-hand column that tallies to 188,000 is the variance that's created as a result of the pro-rating of that $28.50 over a 30-day month, so that's the mechanics -- the mechanical reality of this type of subsidiary, and that's the relief that -- or that's the calculation and confirmation that we're asking the Board.

MR. TAYLOR: Okay. So then as a result of the pro-rating issue, you were deficient in your compensation recovery by 188,000. However, there was a sufficiency of $14,467 as a result of more customers coming on to the system and therefore collecting -- no, actually fewer customers, and therefore you were offering less of a subsidy to customers.

MR. LAVOIE: Just by virtue of customer numbers; that's correct.

MR. TAYLOR: Just by virtue of customer --

MR. LAVOIE: Only eligible customers would receive --

MR. TAYLOR: And so if I were to subtract $14,467 from $188,001 I would end up with $173,534; is that right?

MR. LAVOIE: That should be the calculation, yeah.

MR. TAYLOR: Okay. I've got no further questions for you. Actually, I have no further questions for the panel.

MR. QUESNELLE: So as far as the other unsettled issues, how do you want to proceed, Mr. Taylor? Is this panel going to be responding to cross-examination on all unsettled issues at the same time?

MR. TAYLOR: Yes, that's correct.

MR. QUESNELLE: Okay, thank you.

With that, we'll start cross-examination. Mr. Aiken, I understand you will be going first?

# Cross-Examination by Mr. Aiken:

MR. AIKEN: Yes, thank you.

Good morning. I want to start with how the rural and remote rate protection amount is calculated. So if you turn to page 1 in the compendium, Exhibit K1.1 -- this is table 11 from the settlement agreement.

Am I correct that the amount of the RRRP is the difference between the revenue at the proposed rates for the R1 and R2 rate classes, which in table 11 is 20,714,894 figure in the top half of the table, and the amount calculated using the indexing methodology in the bottom half of the table, which totals $6,824,951?

MR. LAVOIE: That's currently how it's calculated.

MR. AIKEN: Yeah. And then just to confirm, is the transformer allowance of $74,096 already included in the R2 figure of $979,696?

MR. BRADBURY: No, it is not.

MR. AIKEN: Then my question is, why is it in this table? Because it's not included in the figure of 6,824,951.

MR. BRADBURY: The transformer allowance, going back to the previous rate application, there was no allowance made to include the recovery or add-back of the transformer allowance. So going on the premise that the rates of the R2 class can only increase by the RRRP adjustment factor, then you increase the revenue requirement that's calculated on current rates by these -- in this case 0.79, which is -- what Board Staff has determined to be the RRRP adjustment factor.

The only way to recover your transformer ownership allowance is to add it to the revenue requirement following the adjustment of the .79 percent, because it was not in the previous -- it was not in the base amount.

MR. AIKEN: So just to clarify, is the 74,096 included in the 20,714,000? Because it sounds like you're saying it is included in one of them but not in the other one. That's where the confusion that I'm having comes up.

MR. BRADBURY: No, it isn't. It is included above...

MR. AIKEN: So this table would be the same with that line removed.

MR. BRADBURY: If you take the line -- the transformer lines out at the fourth column from the bottom of the table then the RRRP funding amount would be reduced by $74,000.

MR. AIKEN: Well, that's my question, because if -- my understanding is a 13,964, which is your RRRP number --

MR. BRADBURY: Yeah.

MR. AIKEN: -- that's a difference between the 2,714 and the 6,824.

MR. BRADBURY: 6,824 is included in the 74,096.

MR. AIKEN: No, it doesn't.

MR. BRADBURY: It doesn't?

MR. AIKEN: That was my original question. If you take the R1 and the R2 numbers and add them up, the 5,845 and the 979, you are going to get the 6,824. That was why I asked, why is this $74,000 number in here if it's not already included in either the R1 or the R2 under the indexing methodology? Because it's not added into the total.

MR. BRADBURY: Bear with me just a second. I'm going to open up the live spreadsheet.

So the formula is -- it is the 20,000,714 plus the 74,096 minus the sum of the revenues from R1 and R2, so --

MR. AIKEN: And does the sum of the revenues from R1 and R2 include the 74,000? In other words, are you adding it in and subtracting it off? And this table would appear to show that.

MR. BRADBURY: That's what I'm doing. That wasn't my intent, but that's, in effect, what has happened here. My intent was to add 74,096.

MR. AIKEN: Okay. Would you undertake to provide an updated table 11?

MR. BRADBURY: Yes, I will.

MS. DJURDJEVIC: We'll give that Undertaking No. J1.1.

UNDERTAKING NO. J1.1: TO PROVIDE AN UPDATED TABLE 11.

MR. AIKEN: Now, just as an aside while we're on table 11, if you look at the shaded line that's labelled "residential R2" in the bottom part of the table, and the line immediately following it, I see that the monthly service charge for the R2 rate class is $600.83 in one line and 596.12 in the other.

MR. BRADBURY: Yes.

MR. AIKEN: Is this because the existing charge of 596.12 is already above the customer unit cost per month, the minimum system, with PLCC adjustment?

MR. BRADBURY: No, the reason it's held at 596 goes back to the previous rate application, in which the parties agreed that the fixed service charge for R2, since there are only two rate categories, R1 and R2, so the fixed rate for the R2 should not go above what was currently in rates in 2010, which was the 596 number, so in all rate designs since the last rate application the -- after we make the adjustment to -- of the RRRP adjustment factor to both the fixed and variable rate, then we ratchet the fixed amount back to 596.

MR. AIKEN: Okay. Maybe you could go, then, to page 10 of the compendium.

And while you're going there, I'll ask you this. Why do you believe that the agreement in the last settlement agreement, on this particular issue, would carry forward?

MR. BRADBURY: I have no preference, I suppose, one way or the other. It is just that the rate -- the settlement in the previous one, which was accepted by the Board, and -- and it was basically at the intervenors' insistence. It was the School Energy Coalition, actually, in the record that wanted it held. And I've held to that same rate design ever since. It's purely stemming out of that.

From a true view of the regulation, both the fixed and variable ought to increase by the RRRP adjustment factor, in my view. And that's what the rate design in 2011 did.

But out of the settlement -- and it wasn't tied to the floor or ceiling; it was just a rate design and a settlement issue that the fixed amount for the R2, since many of the customers are maybe just slightly over the 50-kilowatt demand, it was felt by the parties to that agreement it should be held fixed. But it had no -- it had no bearing on the floor and ceiling on the -- on page 02 of the cost allocation model. It didn't factor into it.

MR. AIKEN: So if you go to page 10, which is sheet 02 of the cost allocation model, would you agree that another rationale for keeping it at 596.12 is the fact that that is above the ceiling of 344.53 for the R2 rate?

MR. BRADBURY: It can be described. I don't think that was the discussion back then, because really for the R1 and R2, the cost allocation model, the floor and ceiling ought to have no bearing on it. The regulation says that the customers in this class shall see a rate increase equal to the average rate increases of all other LDCs that rebased in the most recent year.

By varying the fixed or variable at all from that premise, then not all customers get that rate increase, because once you hold a fixed rate constant, the smaller -- the smaller customers, the ones closer to the 50-kilowatt range, the smaller customers of that class, they enjoy a rate increase something less than the RRRP adjustment factor.

With our larger customers in the resource industries, the ones with 1,000 or 2,000 kilowatt a month demand, they will get a substantially higher increase than the RRRP adjustment factor. And it is purely due to the slope of the cost curve when you change a variable number.

MR. AIKEN: Okay. Then going back to page 1 and table 11, and how the RRRP is calculated, is the methodology we went through earlier the same methodology as used in the 2011 cost of service proceeding?

MR. BRADBURY: With the exception of the add-back of the transformer ownership allowance.

MR. AIKEN: Okay.

MR. BRADBURY: We've used the exact same methodology in each one of our -- because the way in which Algoma's rates are derived, we can't use the traditional IRM methodology.

MR. AIKEN: That was going to be my next question, is: How was the RRRP amount calculated for the last three years under the IRM?

MR. BRADBURY: Basically, the total revenue requirement is inflated or indexed by the IRM index that's assigned to Algoma for its class -- or for its ranking, same as it would be for any other utility.

So from a seasonal and street light class, there is absolutely no problem. We just -- same as every other utility in the province, we will just apply the IR -- the annual indexing factor that comes out of the IRM mechanism.

However, for the R1 and R2 classes, because the average increase during the IRM period was well above what the IRM increase was, for instance, we were seeing increases from an IRM point of view of 1 or 1.2 percent, but we were seeing 3.75 percent increases in the average. So the adjustment factor would increase the rates for the R1 and R2 above the -- this is hard to explain.

Essentially, we would take the allocated revenue requirement to those two revenue classes, increase it by the IRM number. We would increase the rates charged to the R1 and R2 class by the RRRP adjustment factor. So if the rates go up, the RRRP funding goes down, to hold it constant.

MR. AIKEN: Maybe I can try to simplify this with an example.

So you look at table 11 and you see the revenue requirement of 20.7 million. It's that number that would be increased by the price cap. So if the price cap was 1 percent, it would be 1 percent on top of the 20.7?

MR. BRADBURY: Yes.

MR. AIKEN: So say for 2016, if the adjustment factor was 2 percent, that 2 percent would be applied to the R1 and R2 rates and basically increase the 6.8 million by 2 percent?

MR. BRADBURY: Yes.

MR. AIKEN: And the difference would be the RRRP funding?

MR. BRADBURY: That's right. RRRP funding would go down by the difference, so we are all revenue neutral.

MR. AIKEN: I want to turn now to the issue of -- the issue of revenue-to-cost ratios, so if you could turn to pages 6 and 7 -- sorry, 7 and 8 in the compendium, this is appendix 2-P that's been taken from attachment B in the settlement proposal.

And I'm starting at the bottom -- the bottom table on page 7, where we see the composition of the agreed-upon base revenue requirement of approximately 22.8 million. That includes 16.6 million for residential R1, and 4.1 million for the R2 class.

And I'm assuming that these are the same numbers that we saw on table 11; is that correct?

MR. BRADBURY: They should be, yes.

MR. AIKEN: Okay. Would I be correct that if the calculated class revenues shown in the second table on page 7 -- again, the same number -- were higher for the seasonal and/or the street lighting classes, then the R1 and/or R2 rate classes would be lower?

MR. BRADBURY: Yes.

MR. AIKEN: And then the extension of this would be that the figures in the top half of the table back on page 1 would be lower, resulting in a lower RRRP funding requirement?

MR. BRADBURY: Yes.

MR. AIKEN: Now, again, on page 7, the allocated cost to the seasonal and street lighting class total about 4.4 million, and that's in the table at the top, the 3.7 and about 700,000, while the proposed revenue totals -- and this comes from the second table on page 7 -- totals about 2.2 million, 1.967 and 155,000?

MR. BRADBURY: That's correct.

MR. AIKEN: So is the difference, which is about 2.2 million, recovered through the RRRP funding?

MR. BRADBURY: Essentially, yes.

MR. AIKEN: Isn't this -- isn't that a bit of a perverse outcome, because the RRRP funding is not supposed to provide a subsidy to these two rate classes?

MR. BRADBURY: Yes, but if you were to do that, you would make the assumption that the cost allocation model is exact, and you would assign 100 percent to each rate class. And that's somewhat perverse in itself as well.

MR. AIKEN: But how do you get around the regulation, which says no RRRP funding is to go to those two rate classes? And that 2.2 out of that $13.8 million RRRP funding is exactly doing that.

MR. BRADBURY: It is sort of a convoluted –- there's many things as play as well, you know.

You have the cost allocation model. You allocate -- you determine what costs are allocated to each class. It's not a -- I think the Board in its assignment of ranges -- and all parties recognize it is not a perfect model. It doesn't perfectly adjust. And I'm not going to argue -- the Board has set guidelines, and the revenue-to-cost ratios that I'm proposing in this rate application are outside those guidelines by asking for the status quo rates that you point out in these -- if you go to the third table. I'm not arguing all of that.

We presented a cost -- revenue-to-cost ratio on our last application, and, you know, inherently there was an error in it, and we discovered that, and we went through a total review process of that one. It wasn't really discovered until we got into this rate application, when the revenue-to-cost ratios changed so much.

So I don't think -- you know, it's not a perfect factor. I think, you know, to answer your question, or to meet the requirements of what you're saying, I would have to -- I would have to adjust this so based on the outcome of a model I have a revenue-to-cost ratio of 100 percent for each one of my rate classes.

I really don't know if that's the right answer or not, and I -- and I go back to the -- when the Board set the policy, the ranges, I think it recognizes that there is some give and take in the allocation of revenues to the various rate classes.

MR. AIKEN: So that back at appendix 2-P on page 8 --

MR. BRADBURY: Yeah.

MR. AIKEN: And I think you just referenced this, the top table.

MR. BRADBURY: Yeah.

MR. AIKEN: You are not proposing any change from the status quo of ratios for the seasonal and the street lighting classes, and why is that, given that they're outside the Board's range?

MR. BRADBURY: I guess in all of this -- both utility and the -- and through the questions being posed by the intervenors during this process, and the swing in the revenue-to-cost ratios from those that were approved in the previous rate application to the ones that are done here, it gives rise to whether or not it -- at least in my view, it gives rise to whether or not the cost allocation model that is a generic model to fit all LDCs in Ontario was actually working that way for Algoma.

And I've done -- in our evidence we went to great lengths to point out where Algoma is different. And, you know, we're not a municipal utility. We cover a very vast area, geographically vast, and I'm going to use one example, and it's the same example that's cited in the rate application. That's a number 4 circuit that goes to serve primarily two very large resource industries, one being a lumber mill, the other being a precious-metals mine.

This line extends over 89 kilometres across open country, mostly unaccessible. You know, in order to go in and patrol this line and make repairs, we often have to use helicopters, so it is not something that is seen in the majority. And I would say with the exception of Hydro One we are the only utility that's got to do that.

So -- and we have a number of these circuits. We have the circuits going east of Sault Ste. Marie, we have the Searchmont circuit, and a number of others.

They are essentially sub-transmission, but normally following the cost allocation methodology that's been derived we use the same methodology as all of the utilities, and a lot of our distribution assets become allocated based on -- primarily on customer counts, so there is a lot of seasonal customers. There's, you know, there is over 3,000 seasonal customers, you know, probably only twice -- or, you know, twice that many, being residential R1 customers. So they could allocate a great deal of the cost.

But when you actually look at the number 4 circuit, which is -- makes up, you know, close to 5 percent of our book value of distribution assets, just that one circuit alone, 95 percent of the demand on that circuit serves demand customers, a large gold mine and a large forestry operation.

However, when we allocate it -- there are some cottages there. There is -- basically, from my understanding, they were all resource-based towns. The lumber industry is gone or the mine has closed up, and basically there's some homes remaining there, and they are basically in the seasonal class, because they aren't lived in year-round. People still use them as family retreats in the summer months.

But they get allocated, quite a proportion of that cost to that line, because from a count point of view there may be 100 seasonal but only three large industrial customers. But the line is built to a 44 KV standard, built above the standard that we normally see in distribution because of the remoteness. The cost of maintaining it is high, and so those residential or street light or seasonal customers get a disproportionately large allocation of those costs, because the line, as I said before, 95 percent of the demand on that line is to serve resource-based industries.

And I can look at the east-of-Sault line that goes down to a large rock quarry operation there, the big demand load on that line.

I'm not going to disagree with anything you put forward. I don't disagree with the Board's range policy. I know in traditional rate design I should - -if it was -- if I were doing the Canadian Niagara Power rate application and I saw the rates out, I would change them and move -- and use the Board's guidelines that I'll move to the lower boundary within the four years of the incentive or as otherwise directed by the Board.

What I'm asking for in this rate application is I'm asking the Board not to do anything in the test year. Give me my status quo, revenue-to-cost ratios in my test year, allow me time -- now, we have smart meters. Everybody now has a meter that's recording demand. I can determine what the coincident peaks are now. I've had smart meters in place for two years. I can go back now, and I think I can do a better job at cost allocation and come up with a realistic number.

Now, in my last IRM application, which moved to IRM 4 and the PEG calculations, we basically said, you know, and successfully argued that Algoma is different, you know, we're just so big, so vast, and so few customers, we are different, and that Board panel agreed with us to an extent, and they said, We're going to give you what you're asking for right now, but in your next IRM application we want you to come back with a more enduring policy, so for 2016 rates, Algoma has to come back in with a more enduring policy that somehow the Algoma attributes are recognized within the IRM 4 methodology and we have a workable solution going forward.

All I'm asking in -- of the intervenors and the parties is to afford -- afford Algoma the same opportunity that it's looking into its -- the attributes of its system and to come up with an enduring solution to IRM to give me -- or give Algoma one year's grace on the movement of revenue-to-cost ratios, knowing that in the last application we moved them one way, and in this application we'd swing them back the other way, and that really causes a lot of problems for the customers that are not receiving the R2 -- or the RRRP protection, because now we're seeing a lot of volatility in rates, and through no fault of their own. You know, there was an oversight in the 2011 rate application. We've got another model on the table this time that brings them back the other way, so my ask -- or API's ask is to give us one year's grace in the test year for status quo rates. If we can't convince the intervening community and the Board in 2016 that there is a better cost allocation, then in the remaining four years of the IRM -- because we assume -- presupposing we win the argument on IRM in 2016 -- that's another -- well, we'll leave it at that -- to allow us to incorporate it all going forward and not cause this volatility in rates, because what we're faced with is we could -- you could say we should increase the seasonal street lighting because it has a perverse effect on RRRP, and then we come back in 2016 with a more persuasive argument the other way, and then we're pulling it back again, so it's an ask for one year's grace.

I don't dispute any of what you're saying. From a revenue-to-cost ratio, I have no argument for you. What you're saying is right, but let's -- all I'm asking is have an opportunity to get this right going forward, because it's not fair to the customers.

MR. AIKEN: Okay. You've answered a number of my questions.

MR. BRADBURY: It was my goal.

MR. AIKEN: But going back to the table at the top of page 8, can you confirm that in the policy range numbers, you've got a range for seasonal of 80 to 115, that should actually be 85 to 115?

MR. BRADBURY: If you make the assumption that a seasonal customer is the same as a residential R2 customer, it should be 80 to -- 85 to 115.

MR. AIKEN: And you agreed to that in the response to Staff 32?

MR. BRADBURY: I agreed to that in the responses, yeah.

MR. AIKEN: Now, on this -- your IRM proposal that you would be bringing forward, which I guess would be early next year some time?

MR. BRADBURY: We'd have to file by -- based on the current guidelines proposing a change, we'd have to be in in the first tranche.

MR. AIKEN: And you are not sure at this time whether that be for one year or for the remaining four years of your IRM period? That's yet to be determined?

MR. BRADBURY: Well, the goal, from the language of what the Board Panel in the 2014 rate -- they asked Algoma to come up with a more permanent solution. And they agreed with our arguments, but they didn't see it as an enduring solution.

So while they accepted a one year's grace in IRM, by the next time we come back to IRM, we have to have a permanent solution, or accept the ranking in the fifth cohort.

MR. AIKEN: Okay. Now, an IRM application usually has an adjustment to rates.

MR. BRADBURY: Yes.

MR. AIKEN: And not an adjustment of revenue-to-cost ratios, unless they've been agreed to in a previous settlement agreement.

MR. BRADBURY: If the Board directs us -- if the Board directs us in this rate order, when we ultimately get it, to adjust our revenue-to-cost ratios over the incentive rate period, then we'll do that, yes.

MR. AIKEN: And if the Board doesn't do that, will you be including in your IRM application for next year -- for 2016, rather, a comprehensive review of all these cost allocation issues that you've identified?

MR. BRADBURY: That is our intent.

MR. AIKEN: Okay. And am I correct that in the EB-2009-0278 settlement agreement, Algoma agreed to consult with all intervenors prior to proposing any future incentive rate mechanism to set rates in non-rebasing periods?

MR. BRADBURY: That's correct.

MR. AIKEN: Have you consulted with intervenors to date?

MR. BRADBURY: We -- before the first IRM, we consulted with intervenors, and Board Staff were party to those discussions.

And the -- up until -- and under IRM 3, that worked fine. It was not until IRM 4 came into place that -- we used the same methodology, but we argued that the stretch factors and the methodology introduced by our IRM 4 weren't really suitable or applicable to API.

MR. AIKEN: Would Algoma agree to consult with intervenors before it files its IRM application for 2016, especially on things like this -- the cost allocation issues?

MR. BRADBURY: That would be -- actually it would be our desire. We would prefer to work with the intervenors.

MR. AIKEN: Okay. I'm going to go back now to the revenue-to-cost ratios and the tables. And these questions will likely require an undertaking response.

I have three questions, and I'll just read them out in order here.

First, for the street lighting class, what would be the revenue-to-cost ratio for 2015 that would result in a total bill impact of 10 percent?

The second question is: For the seasonal rate class, what would be the revenue-to-cost ratio for 2015 that would result in a total bill impact of 10 percent?

And then third: Based on the increased revenues for the seasonal and street lighting classes that would result from the first two questions, what would be the resulting RRRP funding required as calculated in table 11?

So would you undertake to provide those calculations?

MR. BRADBURY: Subject to addressing the transformer ownership allowance in your earlier question, yes.

MR. AIKEN: Yes. Okay.

MS. DJURDJEVIC: Let's give that Undertaking J1.2.

UNDERTAKING NO. J1.2: (A) for the street lighting class TO ADVISE the revenue-to-cost ratio for 2015 that would result in a total bill impact of 10 percent; (b) For the seasonal rate class, TO ADVISE the revenue-to-cost ratio for 2015 that would result in a total bill impact of 10 percent; (C) based on the increased revenues for the seasonal and street lighting classes that would result from the first two questions, TO ADVISE the resulting RRRP funding required as calculated in table 11

MS. DJURDJEVIC: Does anybody need it repeated on the record? I thought it was pretty clear, but...

MR. BRADBURY: It's straightforward.

MR. AIKEN: I'm going now to a couple of questions on the proposed monthly fixed charges, so if you could turn to pages 9 and 10 of the compendium?

On page 10, to start off with, are the figures on the last line that is labelled "Existing approved fixed charge" the 2014 actual fixed charges? Because I had different numbers that came out of the 2014 rate schedule.

MR. BRADBURY: No, they are not. As I indicated in my earlier discussion, it has been my -- I'm going to say my practice or the rate design practice for Algoma, because of the implications of the regulation that sets R1 and R2, I don't rely on the output of 02 as a guiding principle.

MR. AIKEN: Okay. My question -- if you go back to page 9, under the proposed rates' monthly service charges, I see rates there of 23.34, 596.12 and 26.75 and 98 cents for the four classes.

MR. BRADBURY: Yes. That's correct.

MR. AIKEN: And when I compare them to the numbers on page 10...

MR. BRADBURY: The numbers on page 10 --

MR. AIKEN: Sorry, the existing rates. I believe your existing rates for street lights, the fixed charges is also 98 cents, and your fixed charge for seasonal is also 26.75.

So I take it from that you are not proposing any increase.

MR. BRADBURY: No, I'm not. In order to make the cost allocation model work -- and again in the application, there is a great deal of discussion of it -- we have to use equivalent rates, because there is no allowance in a cost allocation model to put in RRRP funding. So what we have to do is we have to go all the way back to 2007, in which the –- it was the first rate application or the first Board decision that awarded RRRP funding.

So in order to operate a model, a cost allocation model, you have to develop the rates that would recover 100 percent of the revenue requirement in absence of an RRRP. So RRRP funding goes out the window, and you have to put in distribution rates that will recover 100 percent of the funding -- or of the revenue requirement, in order to make the cost allocation model work.

And what we've done every year since 2007, and then it -- well, there was no application between 2007 and 2011. The predecessor company didn't do IRM applications. And they had a cost of service 2007. There was no other proceeding until the 2011 one.

So what we do is we take the cost allocation out of 2007 and you say: Here's the rates that each one of these classes would have to charge its customers to recover 100 percent of the revenue requirement.

I've made allowances or -- the rate designs all through the IRM period, again in the 2014 application, makes allowances so that the rates are equivalent and would recover 100 percent of the revenue requirement. And that's because of the way the cost allocation model works.

So the rates that you see there are a function of the equivalent rates. And the reason you see zero for street lights is in 2007, it was zero fixed, 100 percent variable. In the 2011 rate application, all the parties agreed that there ought to be a fixed component to the street lighting, and a fixed component was developed at -- I think at 96 or 98 cents, and it was developed and agreed upon because it had the least impact on rates for, we'll say the typical street light customer.

MR. AIKEN: Do these fixed charges, the 98 cents and the 2,675, increase during IRM based on your price cap?

MR. BRADBURY: Yes, they'll increase by -- they'll increase as a function of the price cap impact on the overall revenue requirement.

MR. AIKEN: Okay, I'm moving now to the final issue, which is the 2002 to 2007 RRRP funding variance. And as had been referenced earlier this day, I've included the material from your application in pages 11 through 23 of my compendium on this.

So I want to start on page 11 and go through each of the four paragraphs on that page. In the first paragraph you talk about, this matter was not raised as part of the settlement agreement, even though that you had provided evidence in the 2009-0278 case.

When you say it's not raised as part of the settlement agreement, are you -- what do you mean there? That it was not an agreed-to issue?

MR. LAVOIE: Is wasn't tabled or wasn't on the agenda in the settlement agreement.

MR. AIKEN: But you'd also agree that in that settlement agreement it was not listed as an unsettled issue?

MR. LAVOIE: I...

MR. AIKEN: Would you take that, subject to check?

MR. LAVOIE: It wasn't listed in the agreement, but it was -- the Board also remained silent on it in its final determination.

MR. AIKEN: Well, isn't that because it was not listed as an unsettled issue that went to the Board?

MR. TAYLOR: I think we can agree to that, subject to check. I don't think it was listed as a settled issue or an unsettled issue.

MR. AIKEN: Okay. Then in the next paragraph, starting at line 9 -- Mr. Lavoie, you covered this this morning -- it was the 2,850 times the 12 months times the number of customer gives you the 2.33 million; that's correct, right?

MR. LAVOIE: Correct.

MR. AIKEN: Okay. Then the next paragraph, starting at page 15, we're getting into the details of the composition of the $173,000 that you are requesting. And it says here that:

"The variance recorded by API relates to the billing system allocation of the monthly $28.50 credit per customer that existed for RRRP funding in that same time frame. The billing system allocated the monthly credit on a 30-day basis, which left the utility short."

And then you go on with some example of calculations.

So then if you flip to page 19 of the compendium, that paragraph is really referring to the column that's labelled "days prorated variance", and it has a total of $188,001. Is that correct?

MR. LAVOIE: Correct.

MR. AIKEN: Okay. Then back on page 11, the fourth paragraph, first of all, I'm assuming there is a word missing in here. It says:

"Additionally the funding regime did not address the variability in customer accounts."

Is that what it should read?

MR. LAVOIE: Correct.

MR. AIKEN: And then it says:

"As the number of eligible customers changed from 6,824 in 2002 to 6,797 in 2007, the RRRP funding did not keep pace."

It actually increased too much.

MR. LAVOIE: That's correct.

MR. AIKEN: And that refers to the, back on page 19, the customer count variance that totals a credit of 14,467.

MR. LAVOIE: That's correct, reflects the actual decrease over that same period of time --

MR. AIKEN: Okay.

MR. LAVOIE: -- in customer count.

MR. AIKEN: Yes. Then I want to take you to the technical conference transcript which I've included at pages 21 through 23 of the compendium. First, starting at line 9, there is a statement made by Mr. Taylor. Do you accept what he said there on behalf of the company?

MR. LAVOIE: What specifically are you referring to, Mr. Aiken?

MR. AIKEN: Well, right near the end on line 14:

"We think that the 28.50 was correct, and that is why we are not proposing to change that rate in any way whatsoever."

In other words, you have no issue with the 28.50.

MR. LAVOIE: I guess my understanding of Mr. Taylor's statement here is that it's, I think, describing the same thing that we just went through in the pre-filed evidence to talk about -- the 28.50 was the start -- the number that was approved as part of the rate order, and the -- that the number of days the prorating needs to occur over a -- on a daily basis.

MR. AIKEN: I'm asking you to confirm that you have no issue with the correctness of the $28.50 that was used as a starting point.

MR. LAVOIE: As a starting point for what? I guess that's -- I'm missing --

MR. AIKEN: For the calculation of the 2.3 million.

MR. LAVOIE: For calculating $2.3 million, the start point was the $28.50, yes.

MR. AIKEN: And you have no issue that the 28.50 was wrong, that it should have been a different number? It is the same number that was used for Hydro One, and you have no issue with that?

MR. LAVOIE: It's the same number, $28.50.

MR. AIKEN: Okay, so you may have had an issue with it, but you've accepted it.

MR. LAVOIE: I guess I'm missing the question. I'm sorry. Like, the $28.50 was the number that was used to calculate the $2.3 million estimate for RRRP funding that would be required to be funded by Hydro One to Algoma Power, and that number was based on the $28.50, was also based on 6,824 customers over a year. But as we've described, that does vary, the number of customers varied, and the application of that fixed charge over a calendar month varies based on the number of days.

MR. AIKEN: Okay. I'm going to move on then to the transcript of -- sorry, page 22 of the -- or of my compendium, which is page 55 of the transcript. And starting at line 9 you are talking about the second variance, and this is the day issue. And you state:

"And the second branch that existed was how the credit was applied. And Algoma Power had a bimonthly billing system that applied to its residential customers and inherent..."

Sorry, stopping there, "residential customers", you mean both R1 and R2 rate classes, or just R1?

MR. LAVOIE: There was no R1 or R2 classes at the time --

MR. AIKEN: Okay. So it was strictly as a residential class --

MR. LAVOIE: Residential customers, yes.

MR. AIKEN: And then continuing on:

"And inherent in a 28.50 per month it sounds simple, but the months don't have the same number of days, and therefore over a bimonthly period you have to make a billing assumption within that calculation, and we had done so very similar, identical, actually, to the fixed monthly charges that are applied as part of our rate structure applied on a 30-day monthly basis."

So stopping there, and then going back to page 11, this is the same -- sorry, at lines 16 and 17, this is the same 30-day basis you are talking about there; is that correct?

MR. LAVOIE: That's correct.

MR. AIKEN: Okay. So with respect to billing, are you still billing on the basis of a 30-day billing period?

MR. LAVOIE: The fixed charges are applied on a 30-day basis. Correct.

MR. AIKEN: And you were billing on that same basis back in 2002 through 2007?

MR. LAVOIE: That's correct.

MR. AIKEN: So if you were billing on the basis of a 30-day billing period, and not on a monthly basis, why did Algoma -- or back then, I guess, Great Lakes Power -- not calculate the 30-day equivalent of the 28.50 per month, which would be something like $28.11 on a 30-day basis, and apply that credit to the customers?

In other words, it sounds like you billed on a 30-day basis the $20 a month or whatever the fixed charge was, but you gave back the full 28.50 each month, rather than a prorated number based on a 30-day month or, like you said, on -- whatever number of days you billed.

MR. LAVOIE: Well, I -- I don't think we're saying that we did something different. It operated identically to the billing system, which calculated rates based on a 30-day equivalent. And it also gave the credit back on a 30-day equivalent.

MR. AIKEN: But the credit you gave back on the 30-day equivalent, was that the 28.50? Or it was a lower number?

MR. LAVOIE: On a 30-day month, it would have been $28.50. So on a 60-day -- if the billing window was exactly 60 days, it would be twice 28.50.

MR. AIKEN: Okay. You're losing me, because if -- you are saying you are doing it the same way you're billing your monthly fixed charge.

So if your monthly fixed charge -- to make this easy -- was $31 a month, and you billed on a 30-day basis, you were billing the customer $30 for that 30-day period, but instead of giving them -- were you also then giving them the credit of the 28.50, which was on a monthly basis, rather than 28.11, which would be on a 30-day equivalent basis?

I thought I heard you say earlier that you prorated the monthly fixed charge and you also prorated the credit. And I'm sitting here thinking: Well, if you prorated the credit, then why do you have any variance at all? You only have the variance because you gave back 28.50 a month, rather than a prorated amount?

MR. LAVOIE: I guess if you spell it out a little bit more for me, Randy, I don't -- I'm just looking over my notes to see if I can bring us together on this point, because I don't -- we are not talking the same thing here and I'm just -- I guess I'm missing the point here.

MR. QUESNELLE: Mr. Aiken, do you have another area you will be going to as well? I'm just thinking if we could take a break now to allow --

MR. AIKEN: We could take a break. And this is my last area, and –- but --

MR. QUESNELLE: Let's take a break now, and perhaps there's -- over the break, we can perhaps allow the witnesses to gather their thoughts on the questions you've asked so far.

And we'll start again at 11:30 and see if we can clear this up. Okay? Thank you.

### --- Recess taken at 11:10 a.m.

### --- On resuming at 11:34 a.m.

MR. QUESNELLE: Mr. Aiken. Whenever you want to resume.

MR. AIKEN: Thank you.

So let me back up and try and explain this maybe a little bit differently. You did use a proration on the $28.50, and that proration was based on 30 days.

MR. LAVOIE: Correct.

MR. AIKEN: So the credit you gave works out to be 95 cents per day.

MR. LAVOIE: That's what I just wrote down as well, yes.

MR. AIKEN: So if you take the credit of 95 cents per day and multiply that by 365 days, you gave back $346.75, if my calculations are correct, whereas the credit you were receiving was 28.50 a month, which for 12 months would be $342. So you gave back $4.75 per customer per year more than you were receiving.

MR. LAVOIE: That's correct.

MR. AIKEN: And this variance would not have existed if, instead of taking the 28.50 and dividing it by 30 days, if you had taken the 28.50 and multiplied it by 12, divided by 365 -- and you can take it subject to check that the credit then would be 93.7 cents a day, which works out to $342 a year.

MR. LAVOIE: Subject to check, yeah.

MR. AIKEN: Okay. Then if we go back to pages 15 through 17, or specifically page 17, I guess, of the compendium, this is the rates that came out of the RP-2003-0149 rate order. And down in the note you talked about earlier this morning, the 28.50 per month, and then when I look at the residential monthly charge of 19.97, does this mean that your charge to the residential customer would have been $48.47 a month in the absence of the RRRP credit?

MR. LAVOIE: Correct.

MR. AIKEN: Okay. We've talked about the fact that you bill on the basis of a 30-day billing period, but I notice this rate schedule specifically says that the monthly charge, for example, on a residential customer is $19.97 per month. So in your proration you took the 19.97 and divided it by 30; is that correct?

MR. LAVOIE: That's correct.

MR. AIKEN: So for the same reason that you over-refunded customers, did you not in fact over-collect from customers the fixed charge?

MR. LAVOIE: We believe this is a convention that's been used not only by Great Lakes Power, but many utilities throughout the province when we're on a billing cycle that wasn't discrete month -- discrete months.

MR. AIKEN: But if the rate schedule says that your fixed charge is X per month, and you charge X divided by 30 per day, you're collecting more than what the rate schedule allows you to collect; is that not true?

MR. LAVOIE: We believe you have to make an assumption in order to create a daily equivalent rate.

MR. AIKEN: And if the assumption had been to take that fixed charge, multiply it by 12, and divide by 365 to come up with the appropriate customer charge per day, I would agree with you.

But for the same reason that your 30-day -- use of the 30-day month meant you over-refunded the recovery, you actually over-collected from your customers since 2002.

MR. LAVOIE: Our -- again, our position is that we used a 30-day equivalent, and that is an assumption that many utilities have used throughout the province, and we applied that in accordance with practice.

MR. AIKEN: Can you provide some examples of those other utilities that apply that same practice, rather than billing on a true monthly basis?

MR. LAVOIE: To be certain, we can undertake to provide some examples.

MR. AIKEN: Okay.

MS. DJURDJEVIC: We'll make that Undertaking J1.3.

UNDERTAKING NO. J1.3: TO PROVIDE SOME EXAMPLES OF THOSE OTHER UTILITIES THAT APPLY THAT SAME PRACTICE, RATHER THAN BILLING ON A TRUE MONTHLY BASIS.

MR. AIKEN: Thank you, panel. Those are my questions.

MR. QUESNELLE: Thank you very much, Mr. Aiken.

I had an order. I believe, Mr. Janigan, are you up next?

MR. JANIGAN: I am. I am, thank you, Mr. Chair. And I have a compendium that has been put before you dated October 20th, and I wonder if I could have that marked as an exhibit to begin with.

MR. QUESNELLE: Yes, you can.

MS. DJURDJEVIC: That will be Exhibit K1.3.

EXHIBIT NO. K1.3: VECC CROSS-EXAMINATION COMPENDIUM

# Cross-Examination by Mr. Janigan:

MR. JANIGAN: Thank you very much.

Now, my friend Mr. Aiken has gone over some of the ground that I wish to cover, and I'm going to try to deal with some of the gaps in my questions and his questions. Hopefully I don't duplicate anything he said.

But first I'd like you to turn up tab 1, and -- of my compendium. And if I am correct, if you go to section C of that compendium, you've set -- you've set out here both the status quo revenue-to-cost ratios for each of the customer classes, as well as your proposed revenue-to-cost ratios for 2015. And for 2015 in all four cases you were proposing to maintain the status quo ratios for 2015, as I understand it.

MR. BRADBURY: That's correct.

MR. JANIGAN: And under your -- and I believe you've termed your rate proposal a fourth-generation IRM; is that correct?

MR. BRADBURY: Yes.

MR. JANIGAN: And under your fourth-generation IRM, what you're proposing to do is to revisit these revenue-to-cost ratios in the course of the IRM period and make any changes that you believe are necessary as a result of your additional research.

MR. BRADBURY: What I'm asking is in the test year, so under section C, I would maintain status quo revenue-to-cost ratios, and I accept the fact that they're outside of the Board's range. However, in the course of this application and its review many things have come to light in discussing Algoma, as well as -- Algoma is under direction from its 2014 IRM application to make a proposal for rates going forward, either with this cost-of-service application or -- my understanding, either with this cost-of-service application or before it comes back for incentive rate-setting in 2016 to come up with a proposal that's enduring -- an enduring means of setting rates for Algoma.

Algoma is a relatively small utility, not geographically, but a small utility, with 11,000 customers. Really, the solution, in our view, is not to come in with a cost of service every year or a multi-year cost of service. It seems to be unduly cumbersome for a utility that size.

What we would like to do is to propose some form, as we did with IRM 3, work with the intervenor community and Board Staff and come up with some proposal to put before a Board panel in 2016 that will be enduring of the incentive rate-setting period and get us to our next cost of service in -- 2020, 2019? I don't know offhand.

So what I'm saying is we're -- many of the issues that we will be discussing or reviewing in the review over this winter in preparation for the 2016 rate are similar to the issues that impact this cost allocation, those being density and the electrical layout of the line, of the distribution system.

Algoma is not a collection of customers in one geographic area; rather, it is a large geographic area with very dispersed collections of customers. And we'd like to somehow work with the intervenors and experts in the field to see if there is a better cost allocation methodology that recognizes that diversity.

So essentially what we're asking is for one year grace of changing -- I just don't want to get it wrong again, and -- because it's not right for the customers. The customers deserve, you know, over the long run, more stability in their rates. And we're just asking to defer it one year, give the collective wisdom between ourselves and the intervenors and experts in the field, and see if we can't come up with something that is better reflective.

And it may very well be these revenue-to-cost ratios. I'm not saying they won't. I'm not presupposing anything, but I'd like to have the opportunity to examine, so if we are going forward with rates for our customers, there is some stability and a measure of fairness.

MR. JANIGAN: So if I can get my head around the form of this one-year period of grace, are you saying the test year rates would remain in place and the rates for the remaining years of the IRM would be interim? Is that what you're saying?

MR. BRADBURY: No, I'm saying is -- I'm asking the Board to give a decision that allows a rate design and rates for 2015 to be based on the status quo rates.

MR. JANIGAN: Okay.

MR. BRADBURY: In 2016, if all goes well, we will produce a new cost allocation model that all of the parties would have been -- have seen as it was being developed and had an opportunity to debate on it.

And in 2016, we'll say: Okay, here's what a -- we all believe is a correct set of revenue-to-cost ratios. So beginning in the second year of IRM, which will be the 2017 rates, we will begin to implement through a Board order a controlled migration of -- from these status quo revenue-to-cost ratios to a set of revenue-to-cost ratios that the collective wisdom in the room agrees is a proper cost allocation for Algoma, given its unique attributes amongst the distributor population in Ontario.

MR. QUESNELLE: Mr. Janigan, could I interject for a moment here?

Mr. Taylor, I'm hearing what may be -- maybe it's just my interpretation of what I'm hearing, but a bit of a cross-purpose here. The application that's before us is for a one-year cost of service; is that right?

MR. JANIGAN: That's correct.

MR. QUESNELLE: The questions that are coming, Mr. Janigan, when you asked whether the subsequent years would be held interim, were you suggesting that this would -- 2015 would be the initial year of an IRM period? Or that what will be applied for in 2016 will be the test year of the initial -- sorry, the start of the IRM period?

MR. JANIGAN: I guess, Mr. Chair, I was confused as to what exactly is the status of the application, whether or not it is a one-year cost of service, whether or not we were asking now for a four-year IRM, and what exactly will be the test year.

Now, I've -- and I'm sort of getting conflicting -- or at least it's conflicting in my head, exactly what the fit is between this one-year cost of service and the IRM that's proposed.

MR. QUESNELLE: Understood. And yeah, that's what I was getting a sense of, that there was a bit of confusion there.

Mr. Taylor, could you perhaps place on the record exactly what this application is for and what it is anticipated that the Board would receive from 2016 on?

MR. TAYLOR: I'm going to ask Mr. Bradbury to answer that question.

MR. BRADBURY: Certainly. It's my view that this is a 2015 test year application. Our goal at Algoma is to remain under incentive regulation under IR -- a form of IRM 4 for the incentive rate-setting period that will follow this cost of service.

MR. QUESNELLE: Okay. All right. In 2016, what would you be bringing forward and seeking relief from the Board on?

MR. BRADBURY: In 2016, I will bring forward a form of IRM 4 application that stems from the Board's decision in the 2014 IRM application, in which they -- in 2014, the PEG report slotted Algoma into the fifth cohort, or 0.6 stretch factor.

We argued that -- we presented our IRM application for 2014 rates and we positioned that, for various reasons, the PEG methodology is not working. The cost drivers or the coefficients that were developed for an Ontario population of LDCs don't reflect the cost drivers in Algoma.

That Board Panel accepted our argument, but in doing so, they said: We will accept it for 2014, but we expect that Algoma will propose for the -- if we're going to remain under incentive regulation, which we want to do, we would propose an enduring solution.

So that Board gave us a stretch factor of 0.3, but they would only give it to us for 2014. If we were to come back in 2016 without a proposal, and then we're still in the fifth cohort, they would assign us 0.6 and we would accept it.

So what they gave us is the opportunity, when we come back in 2016, to propose something that's enduring for the incentive period. Or at least that's my understanding of it.

MR. QUESNELLE: So this year, the revenue you're seeking for 2015 is to cover off the spend which is anticipated in 2015?

MR. BRADBURY: That's correct.

MR. QUESNELLE: For January 1, 2016, you will be filing an application which has the spend for 2016 as the first year, as a test year for an IRM period?

MR. BRADBURY: No. The spend will be what's approved in this test year, as with any other -- any other utility going into an incentive phase.

MR. QUESNELLE: But this is the start of your --

MR. BRADBURY: This is the start. What we need to design is what is the appropriate stretch factor. So what -- and in doing that, we're -- we have to look at a lot of the attributes. This is the type of things we looked at in 2014, are these long lengths of lines and the difficulty accessing these lines, and the fact that, you know, our density is so low that, you know, we're hanging more transformers to serve -- we almost have a 1:1 ratio of customers to transformers, as opposed to other utilities' something like seven customers per transformer.

So when PEG develops coefficients, I think even -- everyone agreed that we were an extreme outlier, so that Panel accepted...

MR. QUESNELLE: So it's anticipated that the Board will receive an application that will provide a -- as you referred to it -- a more robust and enduring methodology for cost allocation?

MR. BRADBURY: Yes, and then one -–

MR. QUESNELLE: As well as the rationale for a different stretch factor than would be produced otherwise?

MR. BRADBURY: Yes. And also what I propose is a cost allocation model based on this test year. And so basically it's this cost allocation model, but let's look at, you know, our -- should these express lines be categorized as sub-transmission and therefore the allocation of the cost be more -- my understanding is the sub-transmission facility is allocated more closely related to demand, rather than the number of customers it serves, as opposed to a distribution feeder.

Right now, the allocation considers everything to be distribution feeders; there is no sub-transmission allocation.

MR. QUESNELLE: That clears up what the ask is for. And I recognize, and you're giving good characterizations of what you will be seeking and why.

But it is more clear in my mind, if it is for you as well, Mr. Janigan.

MR. JANIGAN: Just so I'm clear, we are dealing with the 2015 cost of service application, which will become the 2016 test year? Is that what you're saying?

MR. BRADBURY: For the purpose of cost allocation, yes, to determine whether the cost allocation that was proposed here -- we wouldn't go through and develop a new test year for 2016.

MR. JANIGAN: Okay.

MR. BRADBURY: We just want to get -- we'd like to get a cost allocation that everyone agrees to and we feel it is the right answer. And my ask has got nothing to really do with -- from our revenue requirement. This is revenue-neutral to us, really, whether you tell us -- other than rate mitigation, if you tell us to collect it from the R1s or the seasonal, the cost allocation just moves 100 percent around.

But, you know, we -- especially Mr. Lavoie, dealing with customers on a daily basis, we don't want to see this volatility in rates. You know, we've had our rates move around a fair bit, you know, from the last cost of service, and rates have been an issue, and before we go out and set, like, a long-term rates that we would see during a regular incentive, we just want to make sure we got it right. Like, if we know we have it right, then we can go and explain to the Algoma Coalition, you know, This is the cost allocation. You know, the collective wisdom says this is the proper way to allocate costs, and then we can look at it and say, We got it right this time. That's all I'm asking.

MR. QUESNELLE: Okay. Thanks, Mr. Bradbury.

MR. JANIGAN: And just so I'm clear, Mr. Bradbury, that the -- your look at cost allocation would commence to affect rates in 2017? Is that what you're saying?

MR. BRADBURY: 2016.

MR. JANIGAN: 2016. So whatever is looked at in 2016 will affect rates in 2016.

MR. BRADBURY: Until we rebase again, yes. Would affect rate -- and again, we're presupposing the Board accepts an IRM proposal that takes us through it, and maybe the Board is going to come back and say, Algoma, we want you on custom IR, or we want to see you every year, in which case most of this becomes a moot point.

But our desire for a utility our size is to find a way to make the incentive regulation work. I think now -- incentive regulation is a lower-cost option. It gives a better solution for the customers, and we just think it's the better way to go forward. We just need to find something that works.

MR. JANIGAN: Just dealing with what is proposed with 2015, if you would come back to tab number 1 and look at part (d).

MR. BRADBURY: Yes.

MR. JANIGAN: Is it fair to say that if the Board was to direct Algoma to increase the proposed revenue-to-cost ratios for either seasonal or the street light class, the offsetting adjustment so as to maintain revenue neutrality would come in either the R1 or R2 class or both?

MR. BRADBURY: My understanding is the R2 would be lowered until it reaches 111.63, and then two of them would be lowered in unison to approach 1.

MR. JANIGAN: Okay, and if you could turn up tab 3, which is appendix 2-B of the settlement proposal, am I correct that if the Board directed such a change, that the revenues at proposed R1 and R2 would not change, as the rates are set by regulation?

MR. BRADBURY: That's correct.

MR. JANIGAN: But the values for R1 and R2 in the class-specific revenue-requirement column would change and go down?

MR. BRADBURY: Sorry, could you repeat that?

MR. JANIGAN: That the values for R1 and R2 in the class-specific revenue-requirement column would change and go down?

MR. BRADBURY: Yes, they would go down, and seasonal street lighting would absorb, so the total would still be 22,000,837.

MR. JANIGAN: And this would in turn change the values of R1 or R2 in the last column, and hence the level of RRRP funding required?

MR. BRADBURY: That's correct, yes.

MR. JANIGAN: It would reduce it. So it's fair to conclude that by not increasing the revenue-to-cost ratios for seasonal and street lighting all electricity customers in the province are seeing slightly higher rates by virtue of the fact they fund the RRRP?

MR. BRADBURY: That's a correct view of it, yes.

MR. JANIGAN: Okay, thank you.

Now, I wonder if you could turn up tab 6, where you -- one of the issues you raise is the functionality of the Board's cost allocation model.

MR. BRADBURY: Correct.

MR. JANIGAN: And in the full paragraph on page 2 you raised a concern about how the revenue-to-cost ratios for seasonal use have changed so much from the approved 115 percent value from the last cost of service to 55.03, which is now 54.97, based on the settlement proposal, when there was no material change in API's distribution system.

MR. BRADBURY: I think we've been -- we've covered off that point several times during the technical conference in the settlement, that, you know, the rate allocation model used to determine the most recent revenue-to-cost ratios did not -- did not contain the property -- proper density allocations; therefore, did not produce the correct results, and revenue-to-cost ratios were changed based on that cost allocation model, and really have moved us in a different direction than we're moving now.

And the output of the cost -- difficult to say. It sent us in a direction in 2012 that's opposite to the direction that the current cost allocation model is sending us.

MR. JANIGAN: Okay. I wonder if could you turn up tab 4. And we go to your application, and it's page 2 of tab 4, which is reflective of Exhibit 7, tab 1, schedule 2, page 7. And we look at the large paragraph towards the bottom of the page, where you state that:

"The cost allocation model filed in your previous cost-of-service proceeding, the inputs requiring to determine the density were left blank."

And I take it that's the mistake --

MR. BRADBURY: Yes.

MR. JANIGAN: -- where in the current application the required inputs were made.

MR. BRADBURY: It was characterized as an oversight.

MR. JANIGAN: Okay. And on tab 8, which is -- of my compendium, which is Board Staff Interrogatory No. 34, Board Staff asked you to rerun the 2015 cost allocation model with this field left blank.

And can you confirm that this resulted in a seasonal revenue-to-cost ratio of 78.77 percent, more than 20 percentage points higher, and a street light ratio of 45.94 percent, not much different than the 43 percent previously approved?

MR. BRADBURY: That were the results of that interrogatory, yes.

MR. JANIGAN: So would it be reasonable to say that the difference between the current cost allocation results and those of your last cost-of-service proceeding is due to API currently completing the cost allocation model this time and inputting the necessary density information as required?

MR. BRADBURY: That's correct. We took no exception to the revenue-to-cost allocation in the application filed.

MR. JANIGAN: And I wonder if you could turn up tab number 4 of the compendium. And this is Exhibit 7, tab 1, schedule 2, page 7. You raise concerns about the fact that with this density input the cost allocation model now places heavier weighting on density versus demand in the allocation of costs; is that correct?

MR. BRADBURY: Yes, and that was addressed -- I think it is limited to 30 percent.

MR. JANIGAN: And if we look at the -- tab number 7, which is Board Staff Interrogatory 33, you suggest that some of the distribution lines may be appropriately considered sub-transmission.

MR. BRADBURY: That's correct.

MR. JANIGAN: But am I correct in the current application you are not proposing to treat any of the distribution assets as sub-transmission for the purpose of cost allocation?

MR. BRADBURY: In the cost allocation model filed we have made no allocation to sub-transmission or bulk assets within the cost allocation model.

MR. JANIGAN: Okay. Is there any reason why you haven't made such a proposal?

MR. BRADBURY: Well, again, in my understanding -- and I've been involved in cost allocation for some time -- the bulk assets were really coming out of Hydro One's sub-transmission system, in which they have these 44 KV lines that are used as -- in the proper engineering sense of sub-transmission. They provide that purpose. And the allowance was made in the cost allocation model to accommodate that functionality.

Up until really delving into this -- this application, I hadn't considered the long runs of line to be what as -- in the classical sense of a definition of sub-transmission. And therefore in the original cost allocation informational filing, the filing in the 2012 and the filing for this most -- this application, we follow the more classical definition that they are distribution lines.

It's only in the retrospect of the great deal of discussion that's taken place since the application was filed, either through interrogatories or the technical conference, that you come to the realization that, you know, we may have, in fact, been allocating these lines improperly.

And these lines, this same issue is what leads to the costs incurred in Algoma that are not incurred by other utilities, and hence the PEG model, in the development of many of its cost drivers, didn't really take into consideration.

MR. JANIGAN: I wonder if you could turn up tab number 5 in my compendium. And this is an excerpt from Exhibit 8, tab 1, schedule 1, page 3.

I'm dealing with your concerns about the heavy emphasis that's been placed on density that you've raised. But isn't the fact that your low density and the fact that it has less than seven customers per kilometre of distribution line precisely the reason that Algoma's residential customers qualify for RRRP?

MR. BRADBURY: It is, and there is no argument there. Density is the reason for RRRP, but that is totally different than how you would do cost allocation and treat density there. I don't see a link there at all.

MR. JANIGAN: Am I also correct that Algoma is the only distributor in Ontario that meets this low-density definition? And qualifies --

MR. BRADBURY: Other than Hydro One, we are the lowest density. I'm not -- I can't answer your question with all certainty for all other utilities.

MR. JANIGAN: Okay. Now, the Board's cost allocation model effectively determines whether a distribution utility is low-, medium- or high-density, and then it describes minimum system customer proportions based on level of density, where a low-density designation means more costs are allocated on a per-customer basis; is that your understanding?

MR. BRADBURY: That's my understanding.

MR. JANIGAN: Can you confirm that the cut-off between low and medium density is 30 customers per kilometre?

MR. BRADBURY: No, I can't. I've been told that by Mr. Harper in the technical conference, but I can't confirm it.

MR. JANIGAN: Okay. If Mr. Harper is correct, would you agree that it may be an argument that with Algoma everything less than seven customer per kilometre, the customer weighting should be even greater than used by the Board model, where low density applies to all utilities with customer density of 30 per kilometre or less?

MR. BRADBURY: I can't. I'd have to do the work. That's what I'm asking, the opportunity to find out.

MR. JANIGAN: All right. Now, in tab 4 of my compendium -- and that's Exhibit 7, tab 1, schedule 1 on page 9 of this particular exhibit.

MR. QUESNELLE: Schedule 2, perhaps, Mr. Janigan?

MR. JANIGAN: I'm sorry, what did I say? Schedule 2 should be --

MR. QUESNELLE: Yes.

MR. JANIGAN: On page 9.

I believe you note here that the Board has not formally established a target range for the revenue-to-cost ratios for the seasonal class. And I believe you explored with Mr. Aiken the fact that you'd used 85 to 115 percent of the same range as the R1 class?

MR. BRADBURY: That's correct. And my only reason, if you look at the Board's policies, there is no seasonal class here. So you have to make an assumption.

MR. JANIGAN: Can you also confirm for me that you've used 85 to 115 percent as the target range for the seasonal revenue-to-cost ratio in your last cost of service application, 2009 to –- 2009-0078?

MR. BRADBURY: I don't remember the exact, but I would have tried to stay consistent with the R1 class.

MR. JANIGAN: So between then and now, nothing arose that would suggest that this is not an appropriate policy range, and that you should propose a different range for the values?

MR. BRADBURY: No.

MR. JANIGAN: If you could turn up tab 6 of my compendium, please?

In both your application and your interrogatory responses, you've raised the concern about adjacent customers having materially different bills due to the customer classification as a reason for not wanting to adjust revenue-to-cost ratios for seasonal customers,

and --

MR. BRADBURY: It's not wanting to, but it's recognizing the challenges that it -- you know, by making these large changes. Yes.

MR. JANIGAN: If you –- that -- it is an impediment?

MR. BRADBURY: An impediment? Is that what you said?

MR. JANIGAN: Yes. An impediment to making those changes.

MR. BRADBURY: I would classify it as an issue of fairness.

MR. JANIGAN: Now, with respect to the bill comparison issue, am I not correct that almost two-thirds of the actual revenue requirement that you've allocated to R1 is covered by RRRP?

MR. BRADBURY: I don't know the exact percentage. I know it's greater than 50 percent.

MR. JANIGAN: So would I be correct in saying that the bill disparity between R1 and seasonal is largely a matter or a result of government policy?

MR. BRADBURY: The evolution of rates is -- likely government policy is a contributor, but it's whether we've allocated the right revenue or cost responsibility to that class is also a contributing factor.

MR. JANIGAN: But in this case, with so much of it being determined by the effect of the RRRP, it seems that government policy has a major impact?

MR. BRADBURY: It is very likely that the residential R1 class is –- you have to realize that residential R1 contains both residential and small general service, that the allocation or allocated -- attributes of allocation to a combined customer class that contains both residential and small commercial may have a different result than one that is containing just seasonal customers, particularly from a demand allocation point of view.

MR. JANIGAN: I wonder if I could turn up -- I wonder if you could turn up tab 11, please.

And I want to look at the Board's filing guidelines for the 2015 cost of service applications, which I'm sure you're aware of. At the top of the page:

"Results from the updated cost allocation model may show some ratios being outside of the Board-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include adjustments to bring them into the Board-approved ranges. In making any adjustments, distributors should address potential mitigation measures if the impacts of the adjustments on the rate burden of any particular class or classes is significant."

You are aware of that, Mr. Bradbury?

MR. BRADBURY: Yes, I am.

MR. JANIGAN: And I wonder if you could turn up tab 10, which is from a settlement proposal, and it is a summary of total bill impacts by customer class.

And for seasonal, the total bill impact ranges from minus 0.33 percent for a low-volume customer --

MR. BRADBURY: 0.33 percent.

MR. JANIGAN: Sorry, what did I say? 0.3 percent for a low-volume customer to 1.63 percent for a high-volume, 1,000 kilowatt per month customer; is that correct?

MR. BRADBURY: I would be careful with my calling it high-volume or low-volume.

MR. JANIGAN: Okay?

MR. BRADBURY: You're correct in assessing the 287 and 1,000.

MR. JANIGAN: These are divided up on the basis of usage, though?

MR. BRADBURY: Yes, they are.

MR. JANIGAN: Given this low level of bill impact, why are bill impacts such a concern for this class in 2015, when other classes are seeing even higher impacts? For example, R2 and street lights?

MR. BRADBURY: I think it's not as much the bill impacts are -- you know, when you're looking at this, you have to look at the quantum of the bill, or the quantum, like -- I know the intervenors also look at the quantum of the all-in kilowatt-hour rate. It is the quantum of the bill for the seasonal that causes Algoma concern, not the bill impact.

Of course, if -- again, if you were to make certain changes, and you may have to pay more attention to bill impact from the point of view of rate mitigation, but it is the quantum of the bill or the quantum of the cost for those customers.

MR. JANIGAN: What you are saying, it is not the increase, it is just the amount that exists now. Is that what you're saying?

MR. BRADBURY: To a certain degree, yes.

MR. JANIGAN: Okay. Looking at the street lighting, the total bill impact under your proposal is a little over 9 percent, and we can see why you are reluctant to introduce a shift in revenue-to-cost ratios for this class in 2015.

MR. BRADBURY: Again, if you were to look at the quantum of the cost of street lighting for the north, for Algoma in particular, it's of concern to the utility.

MR. JANIGAN: Okay. But as I understand, that the -- your IRM adjustment for 2014 was 1.4 percent, and for the preceding years, 2012 and 2013, it was even lower; is that correct?

MR. BRADBURY: I don't recall the numbers off the top of my head, but they signed -- in that magnitude sounds correct.

MR. JANIGAN: Yeah, I think if you look at Exhibit 8, tab 1, schedule 1, at pages 7 and 8, I believe it indicates there that the increases were .38 percent and .88 percent. Does that sound --

MR. BRADBURY: I'm sorry, what was the reference?

MR. JANIGAN: It was Exhibit 8, tab 1 --

MR. BRADBURY: No, your tab.

MR. JANIGAN: Tab 1, schedule 1. Oh, no, it's not in my --

MR. BRADBURY: Oh, it's not in your compendium?

MR. JANIGAN: Pages 7 and 8, the increases were .38 percent and .88 percent.

MR. BRADBURY: If that's what it says in the application, that's correct.

MR. JANIGAN: Okay. Can you tell me whether bill impacts during the IRM period are a concern and a reason for not adjusting revenue-to-cost ratios for either seasonal or street light periods, and this is a contributing factor to your necessity for a review?

MR. BRADBURY: In the previous IRM period?

MR. JANIGAN: No, in the current -- in the forecast.

MR. BRADBURY: In the upcoming?

MR. JANIGAN: Yes.

MR. BRADBURY: I'm certainly concerned with the rate impacts of moving it, but as I've tried to stress many times, I'm -- and dealing on the front lines directly, directly with our customers and listening to our customers, we're also as equally concerned with the quantum of the increase.

MR. JANIGAN: Turning to the issue of rate design, I'd like to start with the R1 rates, and --

MR. BRADBURY: Tab reference?

MR. JANIGAN: If you turn up tab 12, please. And am I correct that the proposed R1 rates that you've set out in the settlement proposal result from applying the .79 percent RRRP escalation factor that the Board released on October 3rd to the approved 2014 R1 distribution rates?

MR. BRADBURY: That's correct.

MR. JANIGAN: And moving to R2 rates, am I correct that a slightly different approach was used here and the .79 percent escalation factor was applied to the R2 rates, but then an adjustment was made to the service charge in volumetric rates so as to set the service charge at the 2014 value of $596.12 and adjust the volumetric charge so as to maintain the same overall level of revenues?

MR. BRADBURY: That's correct. That was done in the intent -- or the spirit of the agreement proceeding that felt that we should not allow the fixed monthly service charge for the R2 to go above what was then the 596.12, so that's been consistent since 2007.

MR. JANIGAN: And I believe you told my friend Mr. Aiken that the upper limit of the service charge in the R2 class that's set out in sheet 02 as $344.53, this was not a contributing factor to the decision to keep it at the 596.12.

MR. BRADBURY: No, all parties realized in the previous application as well as hopefully in this application that if you play with that 596 number and move it to the ceiling of 343, then you really distort the intent of the legislation, which all customers will recognize the average increase of all other utilities, because what you do then is you -- the smaller-volume customers get a break, whereas your larger-volume customers will pay greater amounts, so it's an acceptance of the role that regulation has in rate design as well.

MR. JANIGAN: I'd like to turn to the issue of rate design for street lights. Am I correct that your proposal is to set the service charge at .98 cents per month, which is the current --

MR. BRADBURY: Again, that is consistent with previous orders.

MR. JANIGAN: It was consistent with the currently approved 2014 service charge, and then calculate the variable charge so as to recover the revenue requirement allocated to this class?

MR. BRADBURY: That's correct.

MR. JANIGAN: Okay. And can you confirm that maintaining that .98 cents service charge leads to 13 percent in the volumetric rate from .1537 dollars to .1787 dollars under your proposal?

MR. BRADBURY: I can't confirm that right now. I have no reason to disbelieve. I don't have the numbers in front of me.

MR. JANIGAN: Would you take that, subject to check?

MR. BRADBURY: To confirm that .98 and .17 -- 1787 as proposed here is an equivalent to the --

MR. JANIGAN: It means a 13 percent increase in the volumetric rate while you maintain the .98 percent service charge.

MR. BRADBURY: Okay.

MR. JANIGAN: Okay? And if you can turn to tab 13. In tab 13 you state that this was done so as to maintain continuity with the existing approved rate structure that was agreed to in EB-2009-0278.

MR. BRADBURY: That's correct.

MR. JANIGAN: Now, if we turn to appendix D of the settlement agreement from that proceeding, which is set out in tab 4 -- I'm sorry, tab 14, it should be.

MR. BRADBURY: Tab 14?

MR. JANIGAN: Yes. And we see that the proposed street light rates are .96 percent -- .96 dollars per month service charge and a .1537 dollars per kilowatt-hour volumetric charge.

Can you confirm that these are the rates that ultimately were approved by the Board in 2011?

MR. BRADBURY: To the best of my knowledge, they were, yes.

MR. JANIGAN: Okay, and we also see that in 2007 there was no service charge and that, per the footnote, the 2011 service charge of .96 is the minimum value as calculated by the Board's cost allocation model at the time.

MR. BRADBURY: That's correct.

MR. JANIGAN: Can you explain how increasing the volumetric charge by over 13 percent while keeping the fixed charge unchanged maintains the continuity of the existing approved rate or is consistent with the EB-2009-0278 proposal?

MR. BRADBURY: I would just rely on the negotiations and the settlement back then, and the parties around the table felt that there should be a fixed charge for street lights, that it shouldn't be 100 percent volumetric, and I have tried to maintain it through the incentive rate period and into this cost allocation. It has no -- it has no bearing -- there is no intent or rate design intent on API's side to either control fixed or the volumetric one way or the other. It's just a function of trying to maintain that roughly $1 fixed charge.

In theory, it's -- it introduces greater risk for the utility, if utilities or government agencies go to lighting technology that use kilowatt-hours. And street lights in Algoma are billed on kilowatt-hours, not kilowatts, as with the majority of utilities.

Then the risk is on Algoma for lower revenues and higher savings for municipalities.

MR. JANIGAN: But it seems to represent a break in the continuity, given the fact that there has been a 13 percent increase in the volumetric charge.

Why is this the preferred approach to simply maintaining the fixed/variable split that will be derived from the currently approved rates?

MR. BRADBURY: Again, you are probably crediting me with a lot more thought going into this. It was just an attempt to hold the fixed charge roughly equal.

MR. JANIGAN: Finally, I'd like to look at seasonal rates.

Am I correct that your proposal is to set the service charge at $26.75 per month, which is the currently approved 2014 service charge, then calculate a variable charge so as to recover the revenue requirement allocated to the class?

MR. BRADBURY: That's correct.

MR. JANIGAN: And can you confirm that the results in doing so is a 12 percent increase in the volumetric rate for the seasonal class?

MR. BRADBURY: Again, right here, sitting here, I can't confirm that. I could do the math, but I'm sure it sounds very reasonable. Or sounds like the right answer, I should say.

MR. JANIGAN: I have it here that it goes from $0.1029 per kilowatt-hour in 2014 to 0.1241 kilowatt-hours (sic) in 2015. Does that sound right?

MR. BRADBURY: Sounds right.

MR. JANIGAN: Now, in your application -- which is at tab 13 of my compendium, if you could turn that up, please -- on page 4, you state in lines 14 to 16 that:

"This was done so as to maintain continuity with the existing approved rate structure as agreed to in EB-2009-0278."

MR. BRADBURY: Correct.

MR. JANIGAN: And the EB-2009 settlement proposal increased both the service charge and the volumetric charge from the previously approved values; is that correct?

MR. BRADBURY: Yes.

MR. JANIGAN: So can you explain how increasing the volumetric charge by over 12 percent, while keeping the fixed charge unchanged, maintains the continuity of the existing approved rate, or is consistent with the EB --

MR. BRADBURY: It was the intent of the discussions back in that period. And it is not in any of the official records, but during discussion of the rate design and much of the –- there was a feeling that the majority of the seasonal are low-volume consumers, and we should be aware of that and try not to raise the fixed monthly charge any more than was necessary.

And I've maintain that same -- and that one is -- had a little more thought than, say, street lights, because we do -- we do have a lot of communications with our seasonal customers. We have a lot of seasonal customers coming into our office and, you know -- and as evidenced in the application, you know, they want to be -- residential customers are arguing that they should be residential customers, that they are living there. It is a permanent residence. It's where their driver licenses say they live, different things, and...

And we are aware of what the customers tell us. And when they are coming in -- if they want to look at their fixed charge and that.

And we're aware of that, and that was a factor in my rate design that I -- you know, because it's visible and I -- and I think as a group we felt that we ought to try to control the fixed portion of the bill, give the customer some opportunity to either use less or introduce some CDM measures of their own, to give them some control over their ultimate bill.

MR. JANIGAN: Once again, the same question: Why was this preferred to an approach that would simply maintain the fixed/variable split that would be derived from the currently approved rates?

MR. BRADBURY: Again, I think it was in response to listening to our customers and what our customers are telling us. And we felt there was enough flexibility within the Bard's guidelines to do that and -- and to demonstrate that we're listening to our customers.

MR. JANIGAN: I'd like to deal with the final area, which is the RRRP variance of $173,534.

And my understanding from your discussions with my friend Mr. Aiken, if you look at tab 19 of my compendium, is that not only were the credits to customers calculated on a different basis than Hydro One calculated them, but, as well, the amount that was billed to customers was different than the monthly amount in the rate order; am I correct on that?

MR. LAVOIE: I don't know specifics about Hydro One's billing system.

MR. JANIGAN: Okay.

MR. LAVOIE: But I do know the convention that Algoma Power had used at the time.

MR. JANIGAN: Okay. And that was different?

MR. LAVOIE: I'm explaining what was used, and it's -- it was our understanding and position that that was used by a number of utilities to prorate service charges at that time.

MR. JANIGAN: I guess the question arises: if in fact Hydro -- Algoma Hydro claims to be entitled to this money in the account on the basis of the way in which it has calculated the monthly RRRP credit, are customers entitled to a credit from Algoma with respect to the same issue?

[Witness panel confers]

MR. LAVOIE: Algoma Power has passed that RRRP credit to customers through that billing period.

MR. JANIGAN: But has also collected from the customers for bill payments on a basis that differs from that which is set out in the rate order; is it not?

MR. LAVOIE: I can't confirm that right here.

MR. JANIGAN: But you are saying the practice, the way in which you billed customers for the monthly amount -- which was based on a pro-rata figure that was explored with Mr. Aiken -- was, in fact, your understanding of the standard way in which customers were to be billed?

MR. LAVOIE: That's what I said.

MR. JANIGAN: Okay. The other variation that you describe is in customer numbers. How is that variance calculated?

MR. LAVOIE: I think it's shown on the schedule at the far right customer count variance, so that the number of customers vary each year.

MR. JANIGAN: Okay. You used customer counts at the year-start and the year-end? Is that what you did, or did you do monthly variance tracking?

MR. LAVOIE: I think this table tries to describe the variance on an average basis. The -- so that was the -- best described the -- the undertaking was to try to break the variance into two pieces, so that's what was attempted, to best describe the variance, those two different types of variances here.

MR. JANIGAN: Okay. But that was year-over-year differences that they -- this last column reflects?

MR. LAVOIE: I believe so, yes.

MR. JANIGAN: Okay. Now, in relation to the order that you are seeking from the Board, you've indicated that Hydro One needed some confirmation of the fact that this amount should be paid to Algoma from that account before you could release it; is that correct? Have I got that right?

MR. LAVOIE: Before Hydro One would release it, yes.

MR. JANIGAN: Okay. Hydro One. Where is the money? Is the money in Hydro One or is it with Algoma?

MR. LAVOIE: Hydro One has the funding account.

MR. JANIGAN: Okay, and that's where the money is?

MR. LAVOIE: That's where all of the provincial funding for RRRP is accounted for.

MR. JANIGAN: Okay. And they are -- do you have something from them that says that they are going to be content with a ruling from this Board in a proceeding which they haven't participated that this money belongs to Algoma rather than to them?

MR. LAVOIE: I don't believe that money belongs to Hydro One.

MR. JANIGAN: No, I know, but if Hydro One had no concerns that it didn't belong to them or were convinced that it belonged to you, it would have been released long ago.

MR. LAVOIE: No, I think this is purely a technical issue. Hydro One disburses the money under instruction or to itself based on the regulations that are in place.

MR. JANIGAN: So there is no dispute about where the money should be going. They simply want an order to the effect that it should be released to you. Is that what you're saying?

MR. LAVOIE: Confirmation from the Board that the money should be released to Algoma Power, yes.

MR. JANIGAN: And they're prepared to accept that and release the money if they get that confirmation in this order.

MR. LAVOIE: That's our understanding, yes.

MR. JANIGAN: Can you tell me why this wasn't raised in the context of the last decision?

MR. LAVOIE: I think we explained our position is the Board remained silent on the issue.

MR. JANIGAN: Yes. And what did you think that indicated?

MR. LAVOIE: It is my understanding that if a Board now remains silent on an issue, they don't accept or reject the issue.

MR. JANIGAN: So you think it is still in play?

MR. LAVOIE: Absolutely.

MR. JANIGAN: If it was, why didn't you pursue that following the release of the decision?

MR. LAVOIE: We thought the next application was the appropriate place to bring it up.

MR. JANIGAN: Did you write to the Board after the decision to point out that they missed addressing your request?

MR. LAVOIE: We did not. No.

MR. JANIGAN: Did you at any time, separate from this application or EB-2009-0208, apply for a variance or deferral account for this issue?

MR. LAVOIE: No, we never considered it as a deferral account issue.

MR. JANIGAN: Thank you, Mr. Chair, thank you, panel, for your patience. Those are all my questions.

MR. QUESNELLE: Thank you, Mr. Janigan.

We'll take our lunch break now for an hour, and we'll resume at 1:40. Thank you.

### --- Luncheon recess taken at 12:38 p.m.

### --- On resuming at 1:44 p.m.

MR. QUESNELLE: Please be seated.

I think Mr. Janigan finished off this morning. Any cross-examination coming from the Coalition? Mr. Harmer, you will be examining this afternoon,? Or...

MR. HARMER: Yes, we have a few --

We have a few questions we'd like to ask. I wasn't sure if the -- if Board Staff was -- in terms of the order, if Board Staff was going first or...

MS. DJURDJEVIC: That's fine with us if the Coalition goes first. I just didn't know this morning whether there would be --- have any cross-examination. So happy for you to go first.

MR. QUESNELLE: Please do if you're ready now.

# Cross-Examination by Mr. Harmer:

MR. HARMER: I would just ask if we could flip back to page 19 of 23 of Energy Probe's cross-examination compendium.

Our question is with respect to the RRRP from 2002 to 2007. We're just -- we wanted to clarify what Algoma Power has -- basically, what had happened since 2007. In essence, what has Algoma Power been doing differently so that they're not in the same position with respect to the RRRP account post-2007?

MR. LAVOIE: In 2007, a new RRRP regulation was -- or it was amended by the Ontario government. And at that point, Algoma Power applied for rates and RRRP recovery using that new amended regulation, which basically changed the approach. And the 28.50 per month for residential customers was no longer the format for subsidy for Algoma Power.

So I guess to answer your question, that account -- that accounting variance ended at that point.

MR. HARMER: So it was just -- it's correct to say it was a function of the change in regulation and not a function of any change in Algoma Power practice?

MR. LAVOIE: Correct.

MR. HARMER: Thank you.

I wanted to ask a couple of questions -- or a few questions, I should say, with respect to the fixed/variable split, so the cost-to-revenue ratios.

The first of which is: If the Board guidelines were to be followed as a result -- strictly adhered to, let's say, as a result of this proceeding, would that mean that that approximately 2.2 million in revenue would be allocated to the seasonal and street light classes?

MR. BRADBURY: Not as a result of the fixed/variable split, but as a result of the revenue-to-cost ratio, yes.

MR. HARMER: Thank you.

And would that be, would that 2.2 be evenly split between the seasonal and the street light classes? Or would one class bear the brunt of that 2.2 million increase?

MR. BRADBURY: On a quantum value, the seasonal class would bear the largest monetary value.

From a percentage point of view, street lights would probably pick up, like, a percentage of its revenue-to-cost ratio, because it's lower right now. It's down in the 20 range.

So as a percentage of overall revenue requirement allocated to a class, street lights would pick up more, but on a quantum of dollars it would be seasonal would pick up more.

MR. HARMER: And so what would the approximate increase -- I'm just looking for a sort of an approximation as to what the increase in rates for the seasonal class would be. Would it be approximately -- would it be fair to say that it would become close to a hundred percent increase?

MR. BRADBURY: Just bear with me. I just want to look at some of the math.

Yeah, it would -- it would almost double the seasonal rate.

MS. DUFF: I just had a quick question on that calculation you're looking at. I guess you have an Excel spreadsheet open there.

Are you taking it to the bottom of the Board-approved --

MR. BRADBURY: No, I'm taking it to 100 percent.

MS. DUFF: Oh, 100 percent? Thank you.

MR. BRADBURY: It's actually -- I'm looking at appendix 2P of the cost allocation rate filing.

MR. HARMER: Another question with -- just a follow-up to that last question would be that approximately 100 percent increase for the seasonal class, that would result in a -- essentially a 10 percent -- or a 10-year, I should say, mitigation plan?

MR. BRADBURY: Okay. No. It is not a hundred percent rate increase. It's a hundred percent increase in the revenue that will be allocated to that class.

Right now they're allocated, under the proposals in my allocation, 1.9 million, whereas the study has allocated them at 3.7 million, so...

It's a revenue that I would be required to recover; not necessarily the rates, rate impacts. I don't know what the rate impact would be.

That's the -- that's a quantum of the allocated revenues.

MR. HARMER: But is it correct to say that the rate increase would be substantial?

MR. BRADBURY: Substantially more than 10 percent, yes.

MR. HARMER: Okay. And the reason that Algoma Power is asking for the -- I'm just attempting to clarify. The reason that Algoma Power is asking for the status quo for the test year is that -- is the reason for that solely as a matter of fairness to Algoma Power's customers?

MR. BRADBURY: I don't know if it's a -- fairness yet.

My issue -- or the issue we have is we don't know if the cost allocation model, in the manner we've normally done it, is correctly allocating the cost to the seasonal. Or any of the classes, for that matter, not just a seasonal.

And my fear, or what we want to avoid is if we make a -- if we make a change now, in -- say, for the 2015 rates, so, say, for instance, if Mr. Aiken asked me to do an undertaking -- he asked me to calculate what the revenue share would be in order to achieve a 10 percent rate increase for seasonal. So say, for instance if -- if I calculate those rates and the Board Panel were to say: I think that's the right thing to do for 2015. Bring it up to 10 percent, you know, to the maximum and look at it going forward, my problem of return would be -- is I don't want to increase it and then have a more detailed look at cost allocation, and then turn around and decrease it again.

So I'm thinking, if I hold to that status quo, then the customers are seeing a rate increase, but they're seeing a rate increase because of their share of the revenue requirement increasing at status quo revenue-to-cost ratios. And then once we can get a feel that this is the right revenue-to-cost ratio, then we gradually move to that over the period of time.

It hasn't been the Board's practice in the past to move all the way in one year. Normally during IRM 3, my experience is saying, Okay, in three equal increments over the three years, move from where you are now toward the lower boundary of the Board's range.

MR. HARMER: And you had said that the intervenors would have an opportunity to be involved in the process of establishing sort of that go-forward approach. How would you envision...

MR. BRADBURY: The reason I say that is, amongst the intervenor community there is a fair bit of expertise in cost allocation, and I think if we were to come forward and make a proposal to the Board with 2016 rates and the intervenors have already seen it and they say, No, we're sort of on-side with these direct allocations or allocations of -- you know, we agree that certain of the feeders are sub-transmission in nature, and we agree with a different allocation for those assets, then I think it would give the entire process more credence, I guess, coming forward, that it's just not something we're proposing with the -- the last time we did it we actually -- we availed of Mr. Taylor's facilities downtown, and a number of the intervenors and some Board Staff actually came in when we were proposing the IRM 3, and we sat down for -- we sat down for a full day, plus we had a lot of back and forth notes and examples back and forth, and we all sort of agreed that this is the way we would pursue it, and then we submitted that first IRM application, and included within, basically said we had the agreement of the parties, but I think in that case it works well.

MR. HARMER: Thank you very much. Those are --

MR. BRADBURY: If I could just add one more -- I don't think we've ever had an adversarial approach with the intervenors as well, and so I don't anticipate that would cause an issue.

MR. HARMER: Thank you very much. Those are all of our questions.

MR. QUESNELLE: Thank you very much, Mr. Harmer. Board Staff?

# Cross-Examination by Ms. Djurdjevic:

MS. DJURDJEVIC: Thank you, panel.

I'd like to just go back to the transaction in which Algoma took over Great Lakes Power -- well, first of all, was there transaction between Algoma and Great Lakes Power, or was it between Fortis and Brookfield? Can you just clarify that for the record?

MR. KING: The transaction was between FortisOntario and Brookfield.

MS. DJURDJEVIC: Okay. So we haven't, as part of this proceeding, been provided with any of the transaction documents for that purchase and sale. So I'm going to put some questions to you, assuming that certain things happened, and you can correct me, and certainly your counsel can interject, and hopefully subsequent to today some of this material can be filed on the record.

Presumably part of the transaction between Fortis and Brookfield was that Fortis acquired all of the assets, rights, and liabilities of Brookfield with respect to this utility, Great Lakes Power; is that your --

MR. KING: Fortis Ontario acquired the shares of the company of Algoma Power.

MS. DJURDJEVIC: Okay. And could you undertake, or could your counsel undertake to provide those portions of the sale and purchase transaction documents which indicate what Fortis acquired and the transaction with Brookfield? Was it -- and in particular what I'm looking at is what rights and liabilities, you know, that may be related to the RRRP account. How did Algoma come to stand in the shoes of GLP today? How did you acquire whatever alleged or potential rights you have in the RRRP funds? Could I have that undertaking to produce those -- at least portions of the transaction documents?

MR. KING: I think we can provide in confidence certain portions of the share purchase agreement, or share -- the -- yeah, the purchase agreement.

MS. DJURDJEVIC: Okay.

MR. KING: You know, acquiring the shares of the company we bought, you know, bought the assets, including the receivables, acquired all the liabilities, so, you know, we -- as if we were always the owner, so that carried forward.

MS. DJURDJEVIC: Okay, I'll give that Undertaking No. J1.4, and it's to provide excerpts or sections of the transaction documents between Brookfield and Fortis, whereby Algoma acquired the rights and assets of Great Lakes Power.

MR. KING: I just defer to Mr. Taylor with respect in confidence how that process works. I'm not familiar with it. I wouldn't want to be on the public record, given that...

MR. TAYLOR: Well, we're not -- I take it from your question we're not filing the whole share purchase agreement.

MS. DJURDJEVIC: Right.

MR. TAYLOR: The portions that are filed, I don't think you're going to find the language that you're looking for that says we are going to assume all liabilities and receivables, because it's a share purchase transaction, right, so basically they have got -- they get everything, warts and all.

So we can file some information that is going to say that they're purchasing the shares, but it's not going to specifically say, you know, any amounts owing related to RRRP.

I'm not sure if it's going to be as helpful or as transparent as you're hoping for, but what we file we would like to file in confidence, and I guess now would be a good time to canvass whether or not anyone would object to us filing it in confidence.

MS. DJURDJEVIC: On behalf of --

MR. TAYLOR: If the Board would mind that, me canvassing.

MS. DJURDJEVIC: I'm not taking any position that it shouldn't be. I mean, it's acceptable to the Board Staff's perspective, if the Panel feels that, you know, there is evidence that needs -- something in those documents that needs to be on the record, then I suppose that could be dealt with at a later point.

MR. QUESNELLE: Ms. Djurdjevic -- all right, just before we go there, I'd just ask Mr. Taylor if the -- was there an application for the share purchase before the Board?

MR. TAYLOR: Yes, there was.

MR. QUESNELLE: So is it on the record now as to what the -- what we have now on -- in the Board's files as to what the nature of the transaction was?

MR. TAYLOR: I believe so. There was a MAADs application. I wasn't counsel on that file, but I'm pretty sure there was.

MR. QUESNELLE: So if we have a MAADs application that provides basically the same information that it sounds like you would be providing in confidence, we likely have someone already have tested what is to be public and what is to be confidence -- held in confidence, and could we take a look at that first and see if that provides the type of information that is likely to be -- inform you as to whether or not you need more or...

MS. DJURDJEVIC: Certainly. I mean, there is some information on the public record already, but I guess I was trying to get at something more specific with respect to how they acquire receivables and what -- how that flowed through from Brookfield to Fortis, and if, as Mr. Taylor is saying now, there is nothing that, you know, that's more helpful or more specific about this matter, I mean, I'm willing to let it go, assuming that, you know, you take the position that by acquiring the shares they acquired everything, as you indicate, warts and all. I can leave it at that and not pursue it further.

MR. KING: Sure. I guess I would volunteer too that -- I guess the question you're really asking, is the RRRP the old funding, and whether or not we would owe that back to Brookfield, and my position, we do not. We are not aware of anything in the share purchase agreement that would cause us to give that back that happened in 2009, so anything beyond that, and it's not material with regards, in the sense of the size of the transaction itself.

MS. DJURDJEVIC: Okay. Well --

MR. KING: -- if that is clearly what you are trying to get, I'll be open and transparent about that.

MS. DJURDJEVIC: Thank you, appreciate that. That was -- might be part of my questions.

MR. TAYLOR: So, sorry, is there an undertaking or not?

MS. DJURDJEVIC: No, I'm not going to ask for that right now.

So part of the confusion throughout the material, there is references to, you know, that it's API's or Algoma's customers that were overpaid or over-credited, and I just want to, you know, make it clear that it was actually GLP. It was GLP's business, while they ran the utility, it was their customers that received the benefit, not Algoma's.

MR. KING: Well, yes and no. It was GLP's and Algoma Power, which are one and the same, the same company. It's just that the shareholders happen to be different.

MS. DJURDJEVIC: Well, I think there is a whole -- it is a whole different legal entity; they are not one and the same, you know. I'm not going to argue that with you. I realize you folks are all the same people that were there when it was GLP, and which is also mostly the same group which is now part of Algoma, but as a legal entity they're quite separate.

And GLP was the distributor at the time that these RRRP amounts were overpaid, not Algoma. There is no dispute about that, I take it?

MR. TAYLOR: GLPL was the licensed distributor, and now Algoma is the licensed distributor. And I think that when Algoma obtained its license to distribute, GLPL's was extinguished.

MS. DJURDJEVIC: Thank you for clarifying that.

So in the -- I don't have a compendium of my own. All the documents I am referring to are in the other parties' compendiums. In VECC compendium, at tab 15, this is from the application materials. I have a little laryngitis the last few days, so I don't sound particularly clear. If I'm not clear, just ask me to repeat myself.

API states there on page 2 that it has recorded -- very last paragraph on page 2, that:

"There was a variance of $173,000, which has been recorded as a receivable on the balance sheet of API."

And just to go back a step, was that recorded as a receivable on GLP's balance sheet?

MR. LAVOIE: That's correct.

MS. DJURDJEVIC: It was? Okay.

So the RRRP variance issue was discovered before Fortis -- before Algoma took over?

MR. LAVOIE: It existed prior to that transaction, yes.

MS. DJURDJEVIC: When was it discovered? Was it on the first year or -– I mean, you know, we're looking at something that happened seven to 12 years ago, and one of the questions that at least Staff has is: When was it discovered and when did Algoma decide it needed to do something about this?

So when you did your -- when Fortis did its due diligence of Great Lakes Power with a view to acquiring it, was there documentation that indicated that there was this variance that had been accruing all this time?

MR. KING: The legal entity, Great Lakes Power Distribution Inc., it was always on the trial balance as far as we're aware of. When we acquired it, it was there; we were well aware of it.

MS. DJURDJEVIC: Okay. And had -- now, why, if Fortis was aware that this amount was there, why would you not have -- or was there some attempt to negotiate a purchase price that would take account of this $173,000 overpayment so that that part gets spun off or carved out and resides with GLP and Brookfield, and is not something that Algoma inherits? Was that ever part of the discussion?

MR. KING: I think management at the time, as I believe now, believed it was a receivable. And we still believe it is a receivable today, so the story hasn't changed. So it wasn't something that someone going to -- willing to write-off. It's just really -- it should have been collected.

MS. DJURDJEVIC: Okay. In your interrogatory response to one of Board Staff's questions at VECC's compendium, tab 16 -- this says in response to 9 Board Staff 41. And on page 2 you've indicated under "Response," paragraph (a), about the second sentence:

"API does not propose to adjust the historic discounts received by its customers, since to do so would amount to retroactive ratemaking. Rather, API is seeking to recover compensation for RRRP discounts it provided to its customers during the period of 2002 to 2007."

So if we understand correctly, Algoma is not seeking to recover this overpayment from the customers who benefited from the overpayment; do I have that right?

I think actually, it was said in -- paragraph (d) on this interrogatory response, API is not seeking to recover its RRRP underfunding from its ratepayers.

So is that even –- and is the only reason that you're not seeking to do this is because you consider that would be retroactive ratemaking? Or are there other considerations? Like, for example, there's a different generation of ratepayers now than those that had received the benefit theoretically?

MR. LAVOIE: Well, the way that the RRRP funding works is that there is no requirement for the -- there is no design for the API customers to pay for the benefit that they receive. The provincial pool pays for that RRRP funding.

So this variance is part of that same pool and part of the same mechanics, so it would be only appropriate for the pool to pay for that.

MS. DJURDJEVIC: Well, okay. And I realize that's Algoma's position and that's one view of the situation.

Another would be that this is a simple matter of somebody having made a billing error on a strictly contractual basis. Like, I overpaid and now I should be paid back.

In your view, is there a retroactive ratemaking aspect to this that makes that an unacceptable option?

MR. TAYLOR: I'd like to intervene here, because I don't think that the panel has the expertise to comment on whether or not this is or is not retroactive ratemaking.

And perhaps that's something we should deal with in argument. If you feel it is, then you are welcome to make the argument and we'll respond to it.

MS. DJURDJEVIC: Right. Okay. I'm just trying to kind of trying to figure out what -- and we can absolutely do it within argument. I'll move on.

Now, if I understand –- now, Algoma is saying that they should receive this compensation from Hydro One. And that would -- again, you may consider this argument, but is the position that that is not retroactive ratemaking?

MR. TAYLOR: We don't believe there is any retroactive ratemaking going on.

MS. DJURDJEVIC: Can the witnesses at least confirm their agreement or understanding that Hydro One has this pool -- it obtains this pool by collecting it from all consumers in the province, so there are ratepayers who are paying for this pool?

MR. TAYLOR: There is a rate to -- if the Board Panel wouldn't mind --

MR. QUESNELLE: The mechanics of it is something we'd be interested in hearing, Mr. Taylor. So if you have it or your witnesses have it, it's --

MR. TAYLOR: Well, the way it works is pretty straightforward. The IESO collects an amount from all customers in Ontario through its wholesale market service rate. And what it collects in regard to RRRP funding for the province currently is a rate that is 0.13 cents per kilowatt-hour. And that rate is set by the Board and the Board sets that rate every year.

So the IESO collects this money and it gives this money to Hydro One. Hydro One then pays out that money as compensation to everyone who has been giving discounts to their customers, RRRP discounts or credits or subsidies, however you want to call it.

Hydro One maintains a variance account to ensure that it's kept whole, so that insures that the money that it receives from the IESO works out to be the same as the money it pays out to all the people, all the utilities who are offering this RRRP subsidiary pursuant to legislation.

That's the way it works.

Now, there are variances in the account. It changes from year to year, but ultimately the variance account keeps Hydro One whole.

MS. DJURDJEVIC: So this notion of Hydro One having this variance account, do we have anything, any evidence or anything on the record as to...

I mean, there seems to be this sense -- I'm going to jump a little bit out of order in my cross -- that there may be some money lying around with Hydro One and that some truing up or correcting is required.

And I'll just go to the -- at the technical conference, the transcript is -– actually, tab 18 of the VECC compendium has an excerpt from the transcript, which is page 55, and about line 20.

The discussion leading up to that point was about how Algoma has experienced a variance. And then at line 20, Mr. Lavoie says, and I quote -- sorry, line 23:

"So we feel that this type of variability has to be occurring within the Hydro One system and would be trued up at some periodic basis."

So what evidence or information do we have whether there is any variability in the Hydro One RRRP fund, or this is just -- this is an assumption that the witnesses have made?

MR. TAYLOR: I think there are two different issues here. The first issue is variability within the fund; in other words, the difference between what Hydro One is paying out to utilities and what it's recovering from the IESO, and if you want to find some information on that, I would refer you to EB-2013-0396. And that's the most recent case where the Board set their RRRP rate, and there is some pretty good information in there as to Hydro One's variance.

Now, the other issue that -- regarding the variance that was referred to in this transcript, I think what that refers to is the variance between what API was paying out or offering as a discount to its customers and what it was recovering from Hydro One in terms of compensation, so there are two variances going on.

MS. DJURDJEVIC: I appreciate that, but what the witness said at that point:

"We feel that this type of variability has to be occurring within the Hydro One system."

And that's pretty much all the information we have about that on the record. So -- well, you know, we can take it up in argument as to, you know --

MR. TAYLOR: No, I think we can answer.

MS. DJURDJEVIC: -- each of the -- as far as, you know -- I just want to sort of clarify what the understanding of the witnesses of the company is. There seems to be this assumption that there is this pool of money and there must be some variability that happened on Hydro One's part because it happened on Algoma's -- or, sorry, GLP's end, and that there should be some balance.

It may or may not be the case, but what I'm saying is that we don't have anything on the record. What we do know is that the amount of RRRP in the fund is fixed for the years in question. For Hydro One it was 127 million.

So if all those amounts have been disbursed to all the distributors who are entitled to RRRP funding, then what's the thinking as to how Hydro One will get this additional $173,000 to compensate Algoma? Will it be from future fees that it receives from the IESO? So I'm just wondering what the witnesses of the company, you know, thought about, where is this money supposed to come from.

MR. TAYLOR: Well, I think that that -- I don't think the witnesses can really offer you anything on this. I think the thinking is that it's a variance account. It is never really at zero. It is always going up and down from year to year.

The variance is impacted by the provincial demand, right, because they're collecting .13 cents per kilowatt hours, and some years there would be more use than others, and therefore the IESO may collect more or less in any given year and give that money to Hydro One.

So I think what Mr. Lavoie was saying when he said -- was talking about Hydro One, and not sure whether or not Hydro One was experiencing -- excuse me, experiencing the same problem was that we don't know if Hydro One was doing its -- was billing out an -- or prorating its $28.50 discount to customers in the same way that Algoma Power was.

If it was, and therefore it was experiencing some sort of shortfall in its compensation, I think that what Mr. Lavoie was probably referring to, and he can correct me if I'm wrong, was that Hydro One is probably using the money from the pool in order to compensate itself for those deficiencies.

Now, it we have no proof of that. That was just a presumption, and our case doesn't rest on that.

MR. LAVOIE: If I can just -- the one document we shared this morning on Hydro One's current rate schedule clearly shows the 28.50 per customer, so one thing's absolutely sure, is that that would vary by the number of customers, and so that variance on the number of customers would have to be occurring regardless of the prorating question.

So the one variance, I think it has to be a very safe assumption that that has to be occurring, because customers are added and taken from systems on a daily basis.

MS. DJURDJEVIC: In this particular case, I mean, the customer number variance is roughly, you know, 100 customers, and, you know, out of the $173,000 that you are claiming, the variability due to customer numbers is about 14,000, so it's not the biggest chunk here of the variability, but what is your understanding, information, about how other distributors deal with variability in customer numbers for the purpose of RRRP funding?

MR. LAVOIE: I believe Hydro One and Algoma Power were the only ones that were under the -- that regime of $28.50 per month, is my understanding.

MS. DJURDJEVIC: So this morning Mr. Aiken asked some questions about -- when we first of all heard your evidence about how the monthly credit of 28.50 actually turned into 29.45 because your billing system -- GLP's billing system allocated the credit on a -- billed on a 60-day basis, and that's how the discrepancy occurred?

And then as I listened on Mr. Aiken's cross-examination, it appears that there is a billing mechanism that GLP could have used that would not have resulted in overpayment; for example, arriving at a daily rate and then, you know, building your billing mechanism around that.

And if I heard correctly, I believe the witnesses agreed that if a different billing mechanism had been implemented the overpayment would have been avoided. Is there a general agreement with that?

MR. LAVOIE: I have posed the question back to our organization on whether that was possible, and I don't have an answer yet, but it's my understanding that the billing system that we used prorated the costs according to that -- or, sorry, the rates according to that 30-day amount during the -- using the assumption that I talked about this morning, so albeit there is a different way of calculating it, I'm not sure whether our billing system could have accommodated that.

MS. DJURDJEVIC: I think you've indicated elsewhere that it was not a billing system error. You've always referred to it as a mechanistic error.

The question is, you know, it was put to you on Mr. Aiken's cross-examination, was whether there was a way to work with that system to create some kind of formula that would have resulted in more accurate billing.

MR. TAYLOR: Sorry, I'm wondering if Board Staff could clarify, when did anyone here describe it as a mechanistic error?

MS. DJURDJEVIC: Several parts throughout the evidence in the transcript, and not necessarily --

MR. TAYLOR: Well, it was a circumstance that occurred, but I don't think anyone ever said we made a mistake.

MS. DJURDJEVIC: No, no, not a mistake. That there was a mechanistic cause or reason for the discrepancy.

MR. TAYLOR: Okay.

MS. DJURDJEVIC: Sorry if I made it sound as if I had -- it was an error. I will suggest to you that there was an error, but not a billing system error. I would suggest that there was a kind of human error, however understandable it may be, but it could have been avoided, as Mr. Aiken's cross-examination indicated.

So we had a representative of the Algoma Coalition asked how the RRRP regime changed after 2007. If I understood, the answer was that the mechanism or the regulation changed.

Can the panel -- the witness panel explain how the RRRP calculation changed from 2007 on?

MR. LAVOIE: Regulation 44201 was amended in 2007, and it provided a different way of providing the benefit of RRRP to the customers, which is how the calculation works in the evidence today, so the difference between the revenue requirement and the forecasted customer revenues at rates that have been adjusted in accordance with the average in the province is how the calculation of RRRP is now calculated for Algoma Power, so it is a fixed amount. It is not based on a right as such, that the 28.50 per customer or any other amount per customer on any basis is no longer the basis by which the subsidy is calculated or paid to Algoma Power.

MS. DJURDJEVIC: So when you say that it is fixed, it is fixed as an annual, as a total amount for the year; is that...

MR. LAVOIE: Yes.

MS. DJURDJEVIC: Do I have that correct?

MR. LAVOIE: Yeah. And then it has been adjusted in IRM years as well, using the same sort of formula.

Maybe Doug can...

MR. BRADBURY: The Board stipulates the amount of RRRP funding in each one of its rate orders, so after we go through either a rate proceeding or an IRM rate-setting, within the Board's order there will be a dollar value stipulated by the Board that's approved as RRRP funding.

Hydro One will then pay that in 1-twelfth increments, once they receive a copy of the order.

MS. DJURDJEVIC: Well, I -- the period in question, 2002 to 2007, also had a kind -- a fixed amount per year. GLP received 2.3 million -- with the exception of the first and last year, which is 1.5, but in all years it was 2.3. So there was a definite fixed amount per year.

And how is that different from what you have now?

Actually, the more important question is: I understand that you're not any longer having issues with any discrepancy between the amounts that are being received from Hydro One and the amounts that are being credited to customers; is that correct?

MR. BRADBURY: Since 2007 and subsequent to the last rate application, the RRRP funding is calculated as a part of rate design. So basically it's your revenue requirement, less what your rates will require at the approved forecast of customers and loads.

So when you do the various exhibits that the Board asks and what is the revenue that you are going to get from the Board-approved forecasts and loads, so we use all those numbers and we use the rates that will -- in a draft rate order, the Board will have approved rates. We will do that, and we will stipulate what -- the difference between what the revenue gotten from rates and the approved revenue requirement that the Board had given us, and that will be the RRRP funding.

So it has no relationship to number of customers or billing periods; it's purely a quantum value.

Whereas before that, it was said: Okay, you have 6,028 customers. Those many customers times 12 months, times 28.50 is your funding.

So the funding assumed your customers were going to be constant throughout the year, which it never was, and the 28.50.

So it's done in two totally different ways. So what's being done now, there is no -- there is no room for a variance as long as the Board -- you know, you have an approved revenue requirement and you have approved load forecasts and customer forecasts, there is no room for a variance.

MS. DJURDJEVIC: So going back to your comment that RRRP, if I understood correctly, forms part of the utility's revenue requirement -- I mean, the revenue requirement is, for example, 1.9.8, but there is only so much -- there is a cap on the charges that you can collect from customers, because anything more than that would result in rate shock.

So that difference between what you actually get from your customers and what you need to meet your revenue requirement is the RRRP. I suggest to you that makes it part of the revenue requirement.

Are we...

MR. BRADBURY: The difference being it never becomes a real... because what you are told to do is give each one of your customers 28.50 per month, in RRRP subsidy or however. So that's a stipulation.

And based on how many customers you have in a historic period, we estimate the RRRP funding that you are going to need is X number of dollars.

It only lends itself to know that at the end of the subsequent 12 months it's not going to equal, it's not going to be the same, because you based it on a historical approved customer account with a fixed dollar approach.

So as Mr. Lavoie said a number of times, customers are connecting and leaving all the time, so...

MS. DJURDJEVIC: Let me take you back to 2002, '03 time period. And you have this order. It says it's 28.50 to X number of customers, and it is $2.3 million.

Now, was it GLP's opinion at the time that it could not deviate from the 28.50, or it could not factor in that there is higher or lower number of customers and it couldn't factor in that it was billing every 60 days and not every calendar month?

MR. LAVOIE: I mean, the order itself, RP-2003-0149 in the schedule "Rates and charges," under the "Note" says:

"The distribution charges reflect an appropriate $28.50 per month under the program."

So any customer that would read that would say that: I'm a new customer. I'm deserving of the $28.50 per month.

So it's a direction that we felt very clear on at the time.

MR. BRADBURY: On the flip side, under what you're asking us, if a new customer came on partway through the year, we say: No, sorry. I can't give it to you. You weren't in the account when we...

MS. DJURDJEVIC: So if I understand correctly, there was this expectation, even at the outset, that there would be or could be some discrepancy or variance?

MR. LAVOIE: Sure. I think so, yeah.

MS. DJURDJEVIC: And at no point did GLP or Algoma seek a Board order to establish a variance account to track these discrepancies; is that correct?

MR. LAVOIE: Again, the -- I think the regulation is clear on the -- Hydro One has the account upon which it divides the amounts that are to be given to utilities that benefit and customers that benefit from the program.

MS. DJURDJEVIC: Again, going back to be Mr. Lavoie's evidence this morning, it indicated that there had been some discussions with Hydro One with respect to truing up the RRRP amount. And apparently Hydro One indicated that Algoma needs to get an order of the Board.

And was any of this communicated in writing? Are there...

MR. LAVOIE: I believe there's some e-mail transactions on it.

MS. DJURDJEVIC: Would the applicant undertake to file all correspondence between itself and Hydro One with respect to their claim for additional compensation from the RRRP pool?

MR. LAVOIE: Sure. Yes, we can.

MS. DJURDJEVIC: Thank you. That will be --

MR. LAVOIE: I guess subject to the courtesy with Hydro One. I -- I...

MS. DJURDJEVIC: That will be Undertaking J1.5.

UNDERTAKING NO. J1.5: SUBJECT TO NOTIFYING HYDRO ONE, TO PROVIDE ALL CORRESPONDENCE BETWEEN ALGOMA AND HYDRO ONE WITH RESPECT TO THE CLAIM FOR ADDITIONAL COMPENSATION FROM THE RRRP POOL.

MR. QUESNELLE: Mr. Taylor, your client is asking for subject to the courtesy of Hydro One. These would be e-mails in your possession now. Are you going to be seeking Hydro One's permission to provide them to us? Is that what was meant by "the courtesy" or...

MR. LAVOIE: Just looking at protocol. That's all.

MR. TAYLOR: Yes, I think that's what he's talking about, although I think we can provide them -- the courtesy is giving them a heads-up that we are providing these; not asking for their permission.

MR. QUESNELLE: Right.

MR. LAVOIE: Yes.

MR. QUESNELLE: Thank you.

MS. DJURDJEVIC: Thank you.

I believe we've heard in the evidence this morning that the issue of the RRRP was not dealt with in Algoma's last rebasing application. And there was some discussion as to whether -- I believe Mr. Lavoie said: We raised it with the Board and the Board was silent on the issue.

And just to be clear, it was -- it was -- the matter was never brought to the attention of the Board, other than in the form of the application? The matter was not pursued to an oral hearing; is that correct?

I think it's fairly uncontrover -- it's on the record it was not part of the proceeding.

MR. LAVOIE: It wasn't part of the proceeding.

MS. DJURDJEVIC: Nor was it part of the settlement agreement. So my question is: Why, in the last rebasing application, did Algoma just -- to let it go, to not pursue the issue or press it at the time, but in this application has decided that it needs to pursue the matter?

MR. LAVOIE: I think it was one of those things. In the settlement proceeding we were focussing on the larger issues within the application. And it was somewhat of an oversight on our part not to pursue that any further, and certainly made it, I think, a lot more clear in this application on what we were seeking and -- and dealing with it now, so...

MS. DJURDJEVIC: All right. Those are all my questions on the RRRP issue. I have just a few questions on revenue-to-cost ratio and then I'm done, if we can just continue on. Okay.

So as we've heard in the evidence this morning, Algoma has proposed a revenue-to-cost ratio movement for the seasonal class going from 115 percent to 55.03 and for the street lighting class from 43 percent to 24.66 percent.

The Board policy, as we know, is that revenue-to-cost ratio movement should be towards getting within the Board policy range. In this case, Algoma has elected to maintain the status quo, even though that results -- it's moving away from the Board policy range.

Now, in the 2011 -- and in 2011 cost allocation model -- and some of this may have been covered this morning, so it is kind of re-reviewing this for the first time this afternoon -- you've acknowledged that the ratio that you sought then was outside of the range and it needed to be adjusted to come within the permitted bounds. And that's not happening in this proceeding. In fact, you, again, are not following Board policy.

Is there anything -- any response or comment you want to make to that other than what has already been said or maybe in argument?

MR. BRADBURY: Just comment, when you qualified your question right at the very beginning, you talked about the revenue-to-cost ratios that were approved in the 2011 rate application, and those were the ones that were premised on, but as we discussed fairly thoroughly here today between myself and Mr. Aiken, we accept that there were errors made in the 2011 rate application, so to use the 2011 cost allocation as the underpinning revenue-to-cost ratios is somewhat misleading, but it doesn't defer from the intent of your question.

Your question is why I'm not moving -- in essence, why am I not proposing to move to the lower or upper boundaries of the Board's guidelines. And I repeat basically what I said this morning. I'm -- I just want to -- I'd like an opportunity to get it right, and I don't want -- I don't want to implement a revenue-to-cost ratio regime and then come back sometime in the future and say, Okay, we've changed again, and for valid reasons, so, you know, I'm not -- I'm not ignoring the Board's guidelines. I acknowledge they're there, and I know I'm not -- I'm not abiding by them, or API is not abiding by them, but it's an effort to buy time and get it right. And it may very well be close to right, from what I'm...

MS. DJURDJEVIC: So in the interim, until you get it right, which customer -- and the Board approves what you're seeking, which customer classes are going to see higher rates as a result of that?

MR. BRADBURY: Seasonal class are still going to see the highest rates. The overall bill impact is mostly due to variance accounts.

MS. DJURDJEVIC: Well, will there be more costs that are shifted to residential classes as well?

MR. BRADBURY: Not as part of the rate design that's before the Board. I'm asking status quo on all rate classes, given that status quo, I guess you would say, it's changed from the status quo because there was an error made in the 2011 cost allocation, where the density factor was omitted.

MS. DJURDJEVIC: Well, it seems to me -- and I may be missing something here -- but that, you know, if certain classes are not paying, you know, a rate that's closer to cost causality, other classes are going to subsidize.

MR. BRADBURY: Yeah. I didn't understand that to be your question.

MS. DJURDJEVIC: Yes. Sorry.

MR. BRADBURY: That's obvious. The residential R1 class is forecast at 11 -- 111.63, and the residential R2 is forecast at 111.71, as being status quo as per the settlement agreement.

So conceivably at roughly 60 million if they are overpaying by 10 percent, $1.6 million.

MS. DJURDJEVIC: Now, will some of that increase -- will some of that be covered by RRRP funding, seeing that it's residential customers who are going to see --

MR. BRADBURY: Everything that's not covered by the RPP adjustment factor is covered by RRRP funding. That's a function of the regulation for residential R1 and R2.

You know, everyone's -- because we're increasing the revenue requirement from, I don't know, $2 million, is it? I can't -- not -- everyone, even though you are maintaining status quo revenue-to-cost ratios, everyone's proportion, everyone's quantum, has increased. I mean, like, it wouldn't be fair to say, okay, you're increasing your revenue requirement by $2 million, and the R1 class is getting all $2 million of it, of that year. There's -- each class is still picking up their proportion of the delta in the revenue requirement.

MS. DJURDJEVIC: Some of those classes --

MR. BRADBURY: In a quantum of dollars, yes, because the residential R1 and R2 make up -- you know, they are 80 or 90 percent of the revenue requirement, or I suppose not that much, but we'll take a look. Yeah, they're 20 million of 22 million.

MS. DJURDJEVIC: Right. So the -- and some of those customers, like seasonal street-lighting classes, are not eligible for RRRP, so -- but the residential ones are, and --

MR. BRADBURY: Right, but in cost allocation you look at all of the money, because again, I go back to the equivalent rates. You have to go back, and you do your cost allocation as if that rate class were paying 100 percent of its allocated rates in -- its revenue requirement in rates. That's how it works.

MS. DJURDJEVIC: I'd like to discuss one of the interrogatory responses. It is at VECC compendium, tab 6. It's Board Staff 7, Staff 32, page -- page 3, second paragraph, third sentence.

The response states:

"Over the past number of years API has experienced a continued migration of customers from the seasonal class to the residential R1 class. Customers are expressing their awareness of the price differential existing between these two customer classes."

So I suggest to you that, you know, customers are aware that there is a benefit to moving to -- out of seasonal class and the residential class, and as you've indicated in your response, they are migrating away.

Is Algoma doing anything to verify whether customers are actually -- fit the description of a residential customer; that is, they live in their residence eight months or more? I'm not exactly...

MR. BRADBURY: Yes, that question was also asked in interrogatory, and it was discussed, and it was discussed in the previous rate application, and we have a number of criteria that we ask our customers to meet.

Once the customer meets those criterias or signs a paper that they know -- like showing us their driver's licence address or their income-tax return, you know, there is not a lot we can do to question them, you know. People have looked at it and say, Well, you've got smart meter data now, but, you know, someone living in a condominium downtown Toronto may go to Florida in October and come back in March. They are a residential customer. You know, if they meet that criteria, it's -- you know, we have little recourse but to accept them, you know. We can't -- we can't look at our customer and say after they've shown us proof of residency or voter's cards and look at them and say, No, you don't qualify. So that's a tough -- from a customer-service point of view, that's a tough one, but, yes, we do ask for proof, and they do sign a form.

MS. DJURDJEVIC: Okay, and another one of the factors -- well, the four factors that API said they consider when cost allocation is designed -- again, this is the same interrogatory, tab 6 of VECC's compendium, page 2, and the fourth factor is the customer's ability to pay.

Can you explain how that has to do with the Board's, you know, typical policies, you know, for cost allocation, revenue-to-cost ratios, what --

MR. BRADBURY: It is not in the Board's policy, but, you know, we're constantly being told we have to listen to our customers, and Mr. Lavoie and the customer service folks at Algoma, they are getting a steady stream in.

We've had customers come off the grid totally, just say: Disconnect me. I've had enough. I can't afford these prices.

So it is not only the rate design. Like, I'm well aware of the rules, and Mr. Aiken and Mr. Janigan went through and they have copies of the rules and the Board's guidelines in their compendium.

I'm aware of those, but I think as a utility we also have to balance the needs and what our customers are telling us. And right now it's a real concern for us, you know. As the customers move, are coming to us and moving out of the rate class, there's less customers remaining to -- for that revenue pool. They're coming off the grid.

So I would position that one as, you know, we're listening to our customers. Our customers are coming to the -- either phoning or coming to the office and they're expressing a great deal of concern about the quantum.

And I know the rate that the R2 customer is receiving is subsidized, but one, you know -- two customers living door-by-door and they're side-by-side and they sit down and compare their bills, the customer -- the R1 customers, they don't see -- there is no credit on their bill. They only see how much they pay and then the neighbour next door.

And it becomes a customer service issue, so when I state that there, the customer's ability to pay and sustainability of the -- that's a pressure that we face, not necessarily a governing principle of cost allocation.

MS. DJURDJEVIC: Mm-hmm.

MR. BRADBURY: I think we have to be responsive to that.

MS. DJURDJEVIC: Thank you, witnesses. Those are all my questions.

MR. QUESNELLE: Thank you very much, Ms. Djurdjevic. Do you have any questions?

# Questions by the Board:

MS. DUFF: Yes, I just had a question. I've been thinking about the stability of rates.

I mean, the customers will see, as a result of the settlement proposal as it stands right now, they will see a change in their rates?

MR. BRADBURY: Yes, they will.

MS. DUFF: And the demand portion as well as the variable portion?

MR. BRADBURY: The fixed portion.

MS. DUFF: The fixed portion, sorry.

MR. BRADBURY: Yes. They will see some change, yes.

MS. DUFF: And you feel that you'll be able to explain that away when you talk about stability of rates, that there will be a change associated with the distribution portion of their bill, and you are confident that you are going to be able to explain that portion?

MR. LAVOIE: I think so. I think the -- we try to develop a "frequently asked question" type of -- when we have rate increases, so that our customer service department is prepared as they can be.

MS. DUFF: No, I'm just thinking with the Board's concern about customer involvement, that's a perfect touch point, given that you have this sensitivity. I was just concerned about, you know, what extra steps you are going to take to ensure that Algoma's plans in this regard were understood.

MR. BRADBURY: I think also in the settlement agreement we've laid out the outlines of the stakeholdering session as well, that's being led by the Algoma Coalition. And hopefully that venue as well will give us an opportunity to make contact with more customers.

MR. LAVOIE: I guess just to supplement, I wasn't quite sure of the question and I apologize. I think we tried to -- when we do have -- we have had some rate instability on whether -- whether it was in, you know, 2003, when we -- when the utility was unbundled or when the RRRP was first introduced to -- you know, when it was reset, I suppose, in 2007, tried to keep customer groups informed of process and that there are some unknowns and uncertainties about what we're doing and why we're trying to work on the various aspects.

And certainly if we are afforded the opportunity to review cost allocation and those fixed/variable split-type issues is that -- and the stretch factor, those are the types of things that we try to boil down into some understandable terms. Some of it is very complex, as we've discussed today, but to try to break it down into meaningful messages for customers, to know that, A, we're working on it, and B, there is some uncertainty and we'll try to keep them posted.

MS. DUFF: Thank you very much.

MR. QUESNELLE: I just had one question, Mr. Bradbury, I was just wondering.

Talking about the further work and the cost allocation study you'd like to do and your proposal that you'd bring that back to the Board in an IRM in 2016, I'm just wondering. At this point in time, just on a theoretical basis, what would you be looking at as an attribute that would distinguish between the seasonal and residential customers, as it stands now?

Is there something that you anticipate that, in looking at the cost drivers for sub-transmission, the long lines you were talking about, the model as it exists now, is there something that would distinguish between those two that would cause you to think that they might move differently?

MR. BRADBURY: Yeah, there was, actually. And it was raised by Mr. Harper during the -- it was either the technical conference or during the interrogatory conference (sic).

And it pointed to a -- I guess an error in our load forecast, because we said, like, you know -- we were forecasting, I think it was, 140 seasonal customers to come over at -- come over from the seasonal class to the residential class. And when those customers come across, they come across, you know, at the average use per seasonal class.

It was during the interrogatories or technical conference that the intervenors very correctly pointed out: Well, if a seasonal customer is convincing you that they are residential, in all likelihood they're your larger seasonal customers. And they were right, you know. It's a seasonal -- because some of our seasonal customers use just a few hundred kilowatt-hours a year, whereas some others are quite large.

And so the ones that are coming across are coming across with not the average of the class, but they are the larger users in the class. So what -- as an extension of that, we feel that's going to change the demand profile, because previously we had -- like I say, we had moved them across at the average.

And Mr. Harper or Mr. Aiken pointed out an issue with our customer load forecast, which was corrected in the technical conference. And that load forecast now is in the settlement proposal.

So in addition to the idea of density of the sub-transmission, I feel the demand profiles of the customer classes may have changed. And -- because we've had -- we have had, since the last rate application, several hundred seasonal customers that have reclassified. And if the general rule of thinking -- they are the larger customers and they would have moved the demand curve, because we have not updated our demand curves other than for our customers and volumes. We haven't updated the demand curves that underlay the 2006 informational filing.

MR. QWUESNELLE: So from a --

MR. BRADBURY: So we would go back and –- and we're hoping with this smart meter data and all of our commercial customers now having some form of recording meter, we feel that the data we have now may give us a better set of demand curves.

MR. QUESNELLE: Knowing the nature of a seasonal customer and its use of a seasonal property, in moving to a demand-driven as opposed to volumetric throughput -- kind of a proxy for cost driver -- can you not anticipate where that may take you? And again, differentiating between residential and seasonal?

MR. BRADBURY: I think we'd like to have the opportunity to look at some of the smart meter data. We have downloaded some of it, and I've had some looked at, but it will take longer time than really is afforded us in this rate application now.

And then we have seen not only the quantum of the demand, but also when the demand -- API is a very -- it's a winter peaking utility. No question about it. If you look at their load curve, they are a winter peaking utility.

If the seasonal rate class is correcting itself through customer migration, so those customers are on in the December, January period, we'll no doubt hit our peak. Then the –- the coincidence of seasonal load under peak is going to shift.

We do see some -- from the informational filings, we do see some seasonal demand occurring with our one and four coincident peak.

I -- my own feeling and my understanding of the industry is with this truing up of the seasonal -- and what I mean by that is if they are truly residential and they've moved to the residential, we're going to see a minimizing of the seasonal contribution to peak, and as a result --

MR. QUESNELLE: Directionally what would that do to your existing --

MR. BRADBURY: In all likelihood it would relieve the allocation. It would lessen the allocation, because your demand allocators would lessen to the seasonal class.

MR. QUESNELLE: Within the scope of your further study are you planning on taking a look at the other profiles of other -- like, you've got residential in your -- it's based on assumptions and throughput as well.

MR. BRADBURY: We would look at all of our customers. As I indicated -- again, it's in evidence in the application -- all of the load growth that we've seen up there in Algoma since the last -- is attributable to the R2 customer. With base metal prices being quite high for a period there, we've seen the resource industry in mining, we've seen our largest customer increase from probably 2.5 to 3 megawatts, exceeding 6 megawatts of billing demand per month.

They are one of our bigger CDM customers. They are looking for CDM opportunities as well. The only large new customer we've connected is a base aggregates customer that's added, so we've -- looking at our load profiles, we've lost residential load, but we've compensated for it in throughput and demand, as made up in the residential R2 class.

MR. QUESNELLE: So it's your anticipation that directionally you could have a downward direction on seasonal cost causality. What about the street lighting? What do you see there as far as, if you're looking at a review of the current model, what would be different about the street lighting cost allocation?

MR. BRADBURY: I haven't seen anything that will affect street lights in a material way. One of the things that -- in Algoma previously, before the last rate applications and whatnot, there were other customers other than the classical street light -- within the street lighting class, they were called street lighting safety, so for instance, flashing lights at intersections along the -- Highway 17, is it, and up through there, safety lighting and this type of thing were included with street lights. We've since moved those when we did the migration to the new billing system. We've cleaned up a lot of those, and now they're being billed as basically unmetered scattered loads within the residential R1 grouping or -- yeah, I guess that's where the majority of them have gone, because they are, like, flashing roads lights, safety lights, not roadway lighting, so we've more or less purged the street lighting customers of non-street lighting accounts, I guess.

MR. QUESNELLE: So is it fair to say that given the seasonal -- in comparing the seasonal to the street lighting customers, you have less of a concern of a reversal?

MR. BRADBURY: Yeah, I don't think I'm going to see much reversal on street lights. The --

MR. QUESNELLE: Let me finish that. I just want to make sure I got that point across properly. That there would -- if you move directionally towards the bands now, that that would reverse out subsequent to your further study.

MR. BRADBURY: I have no evidence. I have no -- nothing I've seen that indicated that would happen.

MR. QUESNELLE: Okay, that's all I had, Mr. Taylor, questions for this panel. Thank you very much.

Do you want to break for a short period, Mr. Taylor? I know you were going to give -- well, first of all, any -- do you have any redirect?

MR. TAYLOR: No, I don't have any redirect.

MR. QUESNELLE: Did you -- are you anticipating that you would be giving argument in-chief on the element of the RRRP; is that right?

MR. TAYLOR: Well, I understand the intervenors would prefer to go by way of written argument.

MR. QUESNELLE: I recognize that. Sorry, the intervenors would prefer that you also provide that argument in writing from the get-go?

MR. AIKEN: I'm sorry, maybe there's been a bit of a misunderstanding. I had told Mr. Taylor that Mr. Janigan and I had discussed over lunch that the intervenors would prefer to do our argument written and have it due two weeks from today. Whether Mr. Taylor does his argument in-chief orally or in -- by written we hadn't discussed. I don't think -- from my point of view, I don't care one way or the other.

MR. QUESNELLE: Okay, thank you, Mr. Aiken, and from this morning, Mr. Taylor, if I recall, there was an element of your argument in-chief you were going to give orally and then follow with the rest in writing? Is that still the case?

MR. TAYLOR: Well, I was expecting to deal with the RRRP recovery issue orally.

MR. QUESNELLE: Mm-hmm.

MR. TAYLOR: I wasn't aware at the time that the intervenors wanted to proceed in writing on that issue. But now knowing that they would prefer to deal with that by way of writing, I'd prefer just to do it all by writing. I don't see why we would do part of it orally and part of it in writing.

MR. QUESNELLE: That certainly makes sense to us.

Given that, Mr. Aiken, you've said that you'd be prepared in two weeks to file intervenor submissions. I take it, Mr. Taylor, would one week from now -- or when would you propose to be able to provide your argument in-chief? These are fairly narrow issues.

MR. TAYLOR: Well, on the RRRP issue certainly within -- certainly in a week.

MR. QUESNELLE: Mm-hmm.

MR. TAYLOR: I'd have to speak with my client in terms of the other issues. I'm not really sure there is much more to add. Pretty much everything there is to discuss about the rate design I think has been discussed today. So unless I see somebody shake their head no --

MR. BRADBURY: A week is fine for me.

MR. TAYLOR: A week is fine? Okay. I think we're in agreement, a week.

MR. QUESNELLE: Why don't we do that. Mr. -- I take it -- I haven't put dates to that, but if a week from today's date we could receive argument in-chief, a week subsequent? Is that what you're suggesting, Mr. Aiken?

MR. AIKEN: Yes.

MR. QUESNELLE: One week subsequent? And then one week subsequent to that would be for reply? All right.

MS. DJURDJEVIC: Thank you.

MR. QUESNELLE: We'll let the transcript act as the procedural order on that.

Further questions?

MS. DUFF: Just regarding table 11, which was part of the settlement agreement --

MR. QUESNELLE: We should deal with this, yeah --

MS. DUFF: Oh, yeah, no, just, I think there was a transcript undertaking today regarding looking at that table and potentially updating it.

To the extent that you are able to footnote some of the calculations, you know, regarding the underlying formulas, that would be helpful.

MR. BRADBURY: I've -- the calculation is correct. No numbers in that table will change when I do it again. It is done correctly. I just have to do a better job of associating the transformer ownership credit with the revenue requirement so it's clear, but the -- I went through it before lunch, and the math is correct. It is just done in a convoluted manner.

MS. DUFF: Thank you, that's helpful --

MR. BRADBURY: Tend to do that sometimes.

MR. QUESNELLE: So to the extent that anything in the settlement proposal -- we talked about that this morning as well -- is still at play, given where the Board is going to go with its findings on this, the Board assumes that submissions will be made on the premise that the settlement proposal will be accepted by the Board, and we don't really see any reason to provide that at this point.

We could have arguments and deal with it all at once in our decision subsequent to all the submissions. Is that acceptable to you, Mr. Taylor?

MR. TAYLOR: It is.

MR. QUESNELLE: That will just avoid having to put caveats into the acceptance of the settlement agreement, not knowing where the finals are going to land.

MR. TAYLOR: Okay.

MR. QUESNELLE: Okay?

MR. BRADBURY: I would like to add a new table will be provided with footnotes exactly where the numbers are coming from and how they're being applied, so it makes it easier for the reader to understand what I've tried to do there.

MS. DUFF: Okay.

MR. QUESNELLE: Thank you very much. And unless there is anything else, we are adjourned. Thank you.

### --- Whereupon the hearing adjourned at 3:04 p.m.