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Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**
VOLUME:	**Volume 11**	
DATE:	**June 28, 2018**	
BEFORE:	**Ken Quesnelle**	**Presiding Member and Vice-Chair**
	Lynne Anderson	**Member**
	Emad Elsayed	**Member**

EB-2017-0049

THE ONTARIO ENERGY BOARD

Hydro One Networks Inc.

Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, June 28, 2018,
commencing at 9:05 a.m.

VOLUME 11

BEFORE:

KEN QUESNELLE	Presiding Member and Vice-Chair
LYNNE ANDERSON	Member
EMAD ELSAYED	Member

A P P E A R A N C E S

JAMES SIDLOFSKY	Board Counsel
MARTIN DAVIES KEITH RITCHIE	Board Staff
GORDON NETTLETON GEORGE VEGH SAM ROGERS	Hydro One Networks Inc. (HONI)
LISA (ELISABETH) DeMARCO JONATHAN McGILLIVRAY	Anwaatin Inc., Energy Storage Canada (ESC)
SHELLEY GRICE	Association of Major Power Consumers in Ontario (AMPCO)
MICHAEL BUONAGURO	Balsam Lake Coalition (BLC) Arbourbrook Estates
TOM BRETT	Building Owners and Managers Association, Toronto (BOMA)
EMMA BLANCHARD ERIN DURANT SCOTT POLLOCK	Canadian Manufacturers & Exporters (CME)
JULIE GIRVAN	Consumers' Council of Canada (CCC)
BRADY YAUCH TOM LADANYI	Energy Probe Research Foundation
ADA CHIDICHIMO KEON	City of Hamilton
ROBERT WOON	Ontario Sustainable Energy Association (OSEA)
RICHARD STEPHENSON	Power Workers' Union (PWU)
MICHAEL McLEOD	Quinte Manufacturers' Association (QMA)
JAY SHEPHERD MARK RUBENSTEIN	School Energy Coalition (SEC)

A P P E A R A N C E S

BOHDAN DUMKA	Society of United Professionals (SUP)
MARK GARNER BEN SEGEL-BROWN	Vulnerable Energy Consumers' Coalition (VECC)

ALSO PRESENT:

JODY McEACHRAN	Hydro One Networks Inc.

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E X H I B I T S

U N D E R T A K I N G S

Thursday, June 28, 2018

--- On commencing at 9:05 a.m.

MR. QUESNELLE: Good morning, everyone, please be seated. Okay. Are there any preliminary matters this morning? Anything from you, Mr. Vegh?

PRELIMINARY MATTERS:

MR. VEGH: There are -- there will be a couple from the witnesses, but first Mr. Rubenstein told me he had a preliminary matter that perhaps we can address before the witnesses provide evidence.

MR. QUESNELLE: Okay, Mr. Rubenstein.

MR. RUBENSTEIN: Good morning, Panel. As you may recall, I wrote the Board on May 4th regarding the announcement of a tentative deal between Hydro One and the Power Workers Union, a tentative deal between the Power Workers Union and the Board, and requesting certain information. And in the Board's decision on confidentiality in Procedural Order No. 6 dated May 18th, 2018, the Board wrote that it will not at this time require the additional information, but noting that Hydro One had stated that it anticipates the outcome of the vote by PWU members on a tentative settlement by June 27, 2018, and the OEB will provide further direction in this regard once the outcome of the vote on the tentative settlement is known.

Based on a press release issued by Hydro One last night at about 11:00 p.m., my understanding is that the Power Workers Union has ratified a two-year collective agreement with Hydro One, so I would renew my request for the Board to require Hydro One to provide details of the agreed-upon settlement, as well as information detailing the cost impacts and especially the cost impacts as it relates to this application, so the differential between the agreement, as well as what is -- underlies the application with respect to the assumptions made.

MR. QUESNELLE: Okay, thank you. Mr. Vegh, response?

MR. VEGH: Thank you, Mr. Quesnelle.

Now, Mr. Rubenstein, I did mention this on the way in today, and while I don't have an objection, I would appreciate the opportunity to get instructions from the people at Hydro One who are responsible for this matter. As you can tell, this panel is addressing cost allocation and rate design, so we are seeking those instructions for a response, and we would be able to provide that after the morning break if that's acceptable.

MR. QUESNELLE: I think it is, thank you. Ms. Girvan?

MS. GIRVAN: Yes, I would just like to say that we support Mr. Rubenstein's request, thanks.

MR. QUESNELLE: Okay. Thank you. I don't think we need to do a show of hands, but that's fine. Okay. Thank you.

Mr. Vegh, anything else?

MR. VEGH: Thank you. As I mentioned, the witnesses do have a couple of points they would like to address. Maybe I will start with Mr. Andre.

MR. ANDRE: Thank you.

At the end of the finance panel number 2 -- and this appears on page 110 of transcript Volume 4 -- Ms. Anderson, you may recall, you had asked about the appropriateness of an LRAM VA account in the context of a revenue cap approach, and I think that's a question that's still outstanding, and so I wanted to address your question.

So page 39 of the filing requirements for distribution cost-of-service applications -- and I have the quote, but I don't know if we wanted to bring that up if we have it. Excellent. And it's section 2.461, so page 39, I believe. Yes, so 2461. So... Okay. If you could just stop it there.

So Ms. Anderson, in there, right under 2461, you see that says:

> "The lost revenue adjustment mechanism variance account, LRAM VA, is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and the actual revenue loss due to the impacts of CDM programs."

And so while HONI's custom IR proposal has been characterized as a revenue cap -- and I think I have spoken about this a number of times -- the revenue cap is -- you know, the proposed custom index is going to be applied to the prior years' revenue requirement as part of our custom IR proposal, but as I have also mentioned on a number of occasions, we are also going to be providing a load forecast for each of the five years of our application, and we will be calculating rates in each year, taking into account the load forecast for that year. So the rates that the Board will ultimately approve and we will be levying to our customers will have our load forecast assumptions, which include a certain amount of CDM embedded in them in the rates that we charge to customers.

MS. ANDERSON: So just to clarify, the LRAM VA will be plus or minus whatever CDM target is in that load forecast?

MR. ANDRE: Oh, absolutely, yeah, it would.

MS. ANDERSON: And given that we are here, could we call up -- my notes say Exhibit A-3.1, page 7. And I just -- this one goes to perhaps where my confusion was, and I just wanted to clarify something.

MR. ANDRE: And what page was that?

MS. ANDERSON: Yeah, page 7 there. And in the fourth bullet it refers to "will update its billing determinants and cost-of-service parameters in 2021", so am I correct then to say that the 2021 only refers to cost of capital?

MR. ANDRE: No, so as we have talked about, so in the application for 2020 we are going to update the load forecast, which results in billing determinants, for '21 and '22. That's part of our ask, is an opportunity to update the load forecast. So the LRAM VA, of course, at that point in time would be updated to reflect whatever assumptions are made in the load forecast that's provided in 2020 for '21 and '22.

MS. ANDERSON: But the way I understood you saying is that that the billing determinants are being updated each year.

MR. ANDRE: Right, and so the billing determinants are being updated each year to reflect the forecasts that we are providing now. So we are not updating the forecasts we are providing now. So we are giving a forecast for 2019 and 2020, and we will be setting rates in those years to reflect the forecasts that we are asking you to approve now.

But that forecast that we are asking you to approve now has a certain amount of CDM embedded in it. In 2020 we are going to ask the Board per our proposal to update the forecast for '21 and '22, and that is different, so that is an actual update to what we propose the load forecast to be in those years, and it will have different economic assumptions built into it, different CDM assumptions built into it, reflecting the best information available at that time.

MS. ANDERSON: So would it be fair to say that in your proposal you are changing the billing determinants each year based on your proposal, but you are updating those amounts for 2021?

MR. ANDRE: Yeah, and 2022, yeah; that's correct. The distinction between changing them versus updating them, yes; that's correct.

MS. ANDERSON: Thank you.

MR. VEGH: Thank you, Mr. Andre. And Mr. Boldt, I understand you have something you'd like to address as well.

MR. BOLDT: Yes, good morning. On Tuesday we had a discussion regarding Hydro One's understanding of the regulatory requirements that informed the scope of review of Hydro One's time study and its proposal regarding miscellaneous service charges. That discussion caused us to reconsider our interpretation of the OEB's guidance, in particular the paragraph on page 106 of the OEB's 2006 handbook that states:

> "A distributor may determine that a particular service charge -- sorry, a specific service charge is not necessary, as it considers the activity to be part of the standard level of service and the costs are covered or recovered in its regular distribution rates."

As a result, Hydro One proposes to no longer introduce the following specific charges. They would be rate code 1, the arrears certificate; rate code 2, the statement of account; rate code 3, pulling post-dated cheques; rate code 4, duplicate invoices for previous billing; rate code 5, requests for other billing information; rate code 7, income-tax letter; rate code 8, notification charge; rate code 9, account history; rate code 10, credit reference/credit check; rate code 12, charge to certify a cheque; rate code 13, legal letter charge; rate code 31(a), vacant premise move-in with reconnect electrical service at meter; and rate code 31(b), which is a vacant premise move-in with reconnect electrical service at a pole.

Hydro One sees no reason why these activities should cease to be part of the standard level of service and proposes to continue to include the costs for these activities in its distribution rates consistent with its past service. This change will result in a shift of about $341,000 from 2018 external revenues to Hydro One's rates' revenue requirement, which will not materially impact Hydro One's customers.

Additionally, Hydro One proposes to maintain the specification service charge it charges for disconnections and reconnections at the meter, during regular hours and during after-hours, at the current OEB-approved rates.

The rate arising from the time study reflects the cost of the current practice of sending a crew to perform the disconnection or reconnection. Since the time of study, Hydro One has been installing remote disconnect meters which can be disconnected without dispatching a crew. As Hydro One continues to increase the number of remote disconnect meters in service, the overall costs associated with this activity will decline.

Hydro One believes it's appropriate to maintain the existing rate. This change will result in a reduction to the external revenue of $1.3 million, and a revised table 4 of Exhibit E-1, tab 1, schedule 2, has been provided this morning which reflects these changes, and it will be submitted electronically.

MR. VEGH: Thank you, Mr. Boldt. I believe that's all.

MR. QUESNELLE: Thank you, Mr. Vegh.

MS. GIRVAN: Could I just ask a clarification question?

MR. QUESNELLE: Yes, Ms. Girvan.

MS. GIRVAN: With respect to the disconnection charge, can you just clarify what you were proposing and what you are proposing now, the level of the charge?

MR. BOLDT: Yes, if you could just give me one second, please.

As you will find in Exhibit H, tab 2, schedule 3. Sorry, I will just go ahead, then -- okay, here we go. And in table 1, please. On page 5. Just go to page 5, please. Thank you.

As you can see on this table for rate code 18 and 19, you'll see that the first column has $65. And what that is is a collection disconnect/reconnect at a meter during regular hours. So currently it's $65, and our proposal from our time study in 2018 had that cost going to 120, which is right beside the 65.

And below that, which are rate code 20 and 21, which is a disconnect/reconnect at a meter after regular hours, it is currently $185, and the proposal based on the time study was 430.

MS. GIRVAN: So you are maintaining those charges, the 65 and the 185?

MR. BOLDT: Yes, that's what we are proposing.

MS. GONSALVES: Great. Thank you very much.

MS. ANDERSON: Can I just clarify? It does say disconnect/reconnect and I know it's a historical term. When it is charged? Is it upon the reconnect?

MR. BOLDT: It's actually charged when you disconnect the service and then after payment is made, it's charged again to reconnect the service. So it's charged twice.

MS. ANDERSON: Okay, thank you.

MR. QUESNELLE: Thank you, Mr. Vegh. Mr. Shepherd?

MR. SHEPHERD: Thank you, Mr. Chairman. Mr. Andre, I just want to follow up on something you said about the load forecast.

If I understand what you're saying, you have basically a five-year load forecast now, which of course gets older and older and therefore less correct, if you like, as time goes on. And you are saying -- you are balancing predictability against accuracy and in 2020, you are saying let's reset it, let's recalibrate it to get it right, right?

MR. ANDRE: Recalibrate, yes. But it's -- the primary driver for that is the fact that in 2021, we are running the cost allocation model and allocating the costs to the acquireds.

So getting the load forecast right for 2021, the year that we are going to be doing that cost allocation is the primary driver for wanting to recalibrate or update the forecast.

MR. SHEPHERD: Excellent. So the point of this -- if I were the Board Panel, I'd be saying, well, why don't we just do this every year? Why don't we fix it every year? And your answer is, well, A, it's a lot of work and we're not running cost allocation every year, so we do have to do it for 2021, because we have a special purpose, right?

MR. ANDRE: Yes, that's correct, that's what's in our proposal.

MR. SHEPHERD: All right, thank you. Now back to our regularly scheduled programming.

HYDRO ONE NETWORKS INC. - PANEL 7, LOAD FORECASTING & RATE DESIGN, RESUMED

Henry Andre,

Bijan Alagheband,

Clement Li,

John Boldt; Previously Affirmed

CROSS-EXAMINATION BY MR. SHEPHERD (CONT'D):

Mr. Chairman, I have a new exhibit which was provided more than 24 hours ago to my friends, and it is three pages. One is an excerpt from the 2021 cost allocation model from the March filing. The second is from the December filing, the same excerpt. And the front page is a comparison of data on those two pages.

My friends will be familiar with these numbers. Can you confirm that, Mr. Andre, that you are familiar with these numbers?

MR. ANDRE: Yes, Mr. Shepherd, and I do want to just highlight a couple of things here.

I am familiar with the two models, and I was able to verify the majority of the numbers in here. But for some reason -- and I don't know why, Mr. Shepherd -- there are a couple of rows that aren't consistent with both what we had put in our PDF in the pre-filed evidence, and I went so far as to look at what was on the Board's WebDrawer in terms of what was filed, and perhaps it's rows that are not going to matter, so I will just point them out to you.

The total revenue at status quo rates numbers --

MR. SHEPHERD: Yes.

MR. ANDRE: -- if you add it across the six rate classes, you show 34,501,000, for example, for March. When I do that same addition, I get a close number, 33,584,000. So that's not hugely different. But down at the bottom the, net income line -- so that's, I guess, the fourth row with numbers from the bottom. Do you see that line at the bottom, the net income?

MR. SHEPHERD: Yes.

MR. ANDRE: So the number for March is again not consistent with what I saw on the two, both the PDF and the Excel spreadsheet. I get 4,990,000 instead of 4,073,000 as you show there.

But the next one over, I get negative 799,000 where you show a positive 18,423. I tried to figure out why the numbers were coming in different and, like I say, I did go both to the PDF that's in our pre-filed evidence and the -- so if you go to your -- you have attached copies of what you saw. And so if you go to that copy, again the issue is with the number in the net income on allocated assets, which is like towards the bottom.

MR. SHEPHERD: Yes.

MR. ANDRE: As I say, that's not what's in the Board's WebDrawer. I don't know if you were going to refer to that row, but ...

MR. SHEPHERD: Mr. Andre, I just took what was in the Board's WebDrawer and copied it. I provided you with the spreadsheet that I --

MR. ANDRE: Yes, and so I did the same thing, because I have the spreadsheets that were submitted, so that was my first place that I went to. And like I say, all of the other rows add up. But for some reason that row, or those two rows that I pointed out, weren't adding up.

And you know, we could -- so last night, I went to the WebDrawer and pulled out the actual attachment that's in the WebDrawer and found exactly what I said, that all of the rows were adding up except for the ones that I mentioned.

MR. SHEPHERD: Can I suggest, Mr. Andre -- and I will ask for an exhibit number for this, Mr. Chairman, but I just wanted to make sure we are clear on it.

I am not actually going to refer to either of the rows you referred to.

MR. ANDRE: Okay.

MR. SHEPHERD: Can I suggest that in order to get it accurate, when you are finished here and you are feeling fresh and at your best, you can -- maybe we can figure out what the right numbers are and fix this for the Board, even though I am not referring to those rows.

MR. ANDRE: Yes. And, Mr. Shepherd, the information that's both in the PDF and, as I say, last night I went to the WebDrawer and pulled it out, so I have the correct numbers. But the correct numbers are in the WebDrawer, so I am quite comfortable saying that that's where the correct numbers exist.

MR. SHEPHERD: With that caveat, Mr. Chairman, can we give this an exhibit number?

MR. QUESNELLE: Yes.

MR. SIDLOFSKY: That will be K11.1.

EXHIBIT NO. K11.1: SEC BUNDLE OF DOCUMENTS (3 PAGES.)

MR. SHEPHERD: And Mr. Andre, before I get to that -- I am going to get to that in a second, but I wonder if you could turn to page 37 of our compendium, which is K10.7.

MR. ANDRE: And what's the reference in that page of the compendium?

MR. SHEPHERD: Oh, JT3.18-19, page 2.

So here's what I am trying to understand. So these numbers, for example the 25.6, that is -- once you have integrated these acquired utilities, these three, that's the incremental cost to serve them; right? It's not the allocated cost, it's the incremental cost, right?

MR. ANDRE: Right. That's the incremental cost added to Hydro One's revenue requirement, correct.

MR. SHEPHERD: And that's less than they would be paying, which is 36.9, and we had some discussion on Tuesday about what that number is, but right I'm just looking at this evidence. Your evidence says 36.9, so let's leave it at that for now. The extra couple million here or there doesn't matter. That 36.9 is what you say they would be paying if they hadn't been acquired, right, subject to the adjustments you wanted to make on Tuesday?

MR. ANDRE: Right. So just to be clear, so it's -- so for OM&A, for example, it includes their forecast of OM&A over that period, it includes their forecast of capital additions over that period, so, yes, it would be a reflection, subject to the correction or the items that I talked about yesterday, it would be a reflection of what they would be paying had they not been acquired, yes.

MR. SHEPHERD: Now, if you turn to K11.1, in your December allocation -- and you can use the first page, I think, is more easy for people to understand -- under that December column you'll see, about the middle of the page, revenue requirement, 41.2, so that's what your current cost allocation model allocates; right?

MR. ANDRE: Yes, that's correct.

MR. SHEPHERD: So that's essentially on similar -- except that it's fully allocated, it's on a similar basis to the 25.6 and the 36.9.

MR. ANDRE: Yes, the 36.9, with the 2.1 for depreciation, and that other number that I mentioned that I think is really quite important that I spoke with Ms. Anderson about yesterday, that .94 for the upstream distribution costs that are in the 41.2 that you are pointing me to in my model, versus they are not in the distribution costs of the embedded, but if you are going to compare those two numbers, you definitely have to include those upstream --

MR. SHEPHERD: We heard that on Tuesday, but I don't really want to talk about that more today --

MR. ANDRE: Okay.

MR. SHEPHERD: -- and hear the explanation again, because if I give you more opportunity you will keep raising the number again.

The -- I want to then go to March, because in March, using your standard cost allocation now, right, the one that you are using for everybody else, you allocated 46.2 million; right?

MR. ANDRE: Not quite right, Mr. Shepherd. The March model, the difference between the March and the December is essentially that in December we had that different treatment of the distribution stations, and that's what's primarily driving that difference between 46 and 41, it's not what the model would -- I can't remember the words you used, but it's not like the normal allocation. It's the same allocation methodology other than in December we are also adjusting for the distribution stations.

MR. SHEPHERD: And -- well, okay, and the poles and everything else, right?

MR. ANDRE: But the poles and everything else were being adjusted in both the March and December models.

MR. SHEPHERD: Ah. All right. See, the reason I am asking this is because the 46.2 allocates costs to the acquireds on the same basis as all the previous acquireds, right?

MR. ANDRE: No, the 46.2 includes the same adjustment factors for the poles and the transformers and all of those other US of As, and the December one includes those same adjustments plus the adjustment for the distribution station.

MR. SHEPHERD: So actually, for the previous acquireds -- let's just deal with those for now -- the actual costs for them on -- the actual cost to these acquireds on that basis would be even higher, right, because there would be no adjustments for those things, right?

MR. ANDRE: Correct, they would have gone into the normal R1 and R2 classes and would have been allocated costs per the costs allocated to those classes normally.

MR. SHEPHERD: And do you know what that number would be if you were just looking at how much they would have to bear in costs if they had the same deal as the previous acquireds?

MR. ANDRE: Well, our proposal is to create new acquired classes, so if you are asking did we do a run where we moved all of these acquired into the R1 and R2 and our normal classes, no, we didn't do that.

MR. SHEPHERD: So you have no idea what their costs would be if you just treated them like everybody else?

MR. ANDRE: I think you'd have to be more specific about treating them as everyone else. As I said, if you are asking what the costs would have been if they moved into R1 and R2, no, we don't have that run. If you are asking what the costs would be if we didn't apply the adjustment factors, again, we haven't done that run, but that would be simply a matter of removing the adjustment factors from the model.

MR. SHEPHERD: It would certainly be 10- or 20- or $30 million higher, right?

MR. ANDRE: I don't know about the exact quantum, but, yes, it would be notably higher.

MR. SHEPHERD: All right. So here's why I am asking the question. So you have got these 92 acquireds that you have already got in the fold, and then you have got these three new ones. Is it 92? Is that right? Niagara-on-the-Lake said 92, but you said 80 plus --

MR. ANDRE: 89 -- I thought it was 89, and then there was another one -- it's around 90, Mr. Shepherd. I don't know the exact number.

MR. SHEPHERD: Let's say 90 and we will pretend it's right. If -- so those -- the customers in those acquired utilities are paying -- they have a different deal than these ones. This is what you said on Tuesday. They have a different approach to their rates being set. They go into the regular classes, and so the costs that they are bearing are significantly higher than these acquireds; right? It was not just the 46 million, as you say, it's higher than that.

MR. ANDRE: You're correct. The costs are higher, Mr. Shepherd. The proposal around the integration of those 90 acquired utilities was fully explored as part of the 2006 application, and there would have been different circumstances around those 90. I mean, some of those 90 utilities included utilities that had 300 customers, 400 customers. I think it was known at the time that some of those really small utilities hadn't done any kind of upgrade to their assets in a long period of time.

So the circumstances and situation around those 90 utilities would have been very different, very different than what you see here. And unlike in those -- you know, back in 2006 when we integrated them, where we presented the proposal in front of the Board -- in fact, there's initially a proposal presented in 2005 for integrating the acquired utilities that was rejected, and then we came back in 2006 with an alternate proposal, fully discussed with the Board, fully reviewed by intervenors, and that's what we landed on.

For this, we have specific direction on these three acquireds from the MAADs decision from the Board in terms of their expectations with regards to the costs that are going to get allocated to them, so I think the two situations are quite different.

MR. SHEPHERD: Aside from the fact that the Board's given you specific direction, you are not suggesting that Brockville and Lindsay and Owen Sound and Thorold and Trenton are significantly different in terms of acquisitions from Woodstock, are you?

MR. ANDRE: What I am suggesting is that the integration of those utilities and the rate harmonization of those utilities was fully discussed with the Board as part of the 2006 proceeding, reviewed by intervenors, and we followed the Board's direction at that time with respect to integrating those utilities at that time.

MR. SHEPHERD: See, the way I understand this is -- let's say that you would have allocated 60 million to these guys, these three new acquireds. I just want to have a number. I know it's not the right number, but let's say 60 million. And -- if you just followed the same rules as you did the last time around. It seems to me that what you have got here is they would have paid 36.9 or 39 or whatever the number is, and instead they have to pay 60, but the real cost to serve them is only -- the incremental cost to serve them is only 25.6, so you have a savings, but they not only don't get the savings, they have to give more money to subsidize your other customers; isn't that right?

MR. VEGH: If I may, sir, Mr. Shepherd seems to be going back to decisions around 2004, 2005 with respect to cost allocation that have already been addressed by the Board, and the issue in this application is whether the proposed cost allocation and rate design for the new utilities -- sorry, for the new acquireds is consistent with the Board's direction.

And the witness has said this two or three times, so I don't see the value of constantly going back and speculating on what would have happened if the Board made a different direction with respect to the previously-acquired utilities, where the Board has already settled that matter.

MR. QUESNELLE: I took Mr. Shepherd's last comments to be a departure from that line of questions, and basically putting to the witnesses a scenario only talking about the recent acquireds.

MR. SHEPHERD: My question is -- this appears to be unfair to the old ones, the old acquireds, because you are giving this special deal to the new ones. And that may be because the deal for the old acquireds was unfair.

MR. QUESNELLE: Mr. Shepherd, now you are definitely going back to what the Board determined. I think if you pose your questions as to the acquireds -- what's the comparison doing for us, as far as understanding whether or not the direction is involved the issue in this case?

MR. SHEPHERD: Why don't I go there, and then I think you’ll see that the questions I was asking were critical.

Right now, you're proposing to allocate $41.2 million of costs. And the way -- what you did to respond to the Board is you said, okay, first we are going to reduce it from 60 to 46, wait that's not enough because now we’ve got the Orillia decision. Let's reduce it another 5 million because of the distribution stations, ah, that's still not enough. So now we have to reduce it by having those customers at 80 percent, or I think it's 83 percent, revenue to cost ratio just to keep their rates below what they would have paid otherwise.

Isn't that what you ended up doing? Because otherwise, you can't -- Hydro One can't get its costs low enough so that the costs to serve these customers are below what they would have paid. You can't, right?

MR. VEGH: Again, Mr. Shepherd is now creating a narrative around how these costs were allocated. If he has questions around how the costs were actually allocated, he can ask those questions.

But so far it's been a bit of a speech about how he believes what was motivating Hydro One's activities.

MR. SHEPHERD: Well, maybe my friend Mr. Vegh hasn't done as much cross as some other people, because one of the things you do in cross is you put a narrative to the witness and you say isn't that true, and that's what I just did.

MR. ANDRE: I am happy to answer the question. And I would start, Mr. Shepherd, by saying, you know, you went through -- you started here and then I think you mentioned, and then the Orillia decision came along and you thought, okay, the costs were too low.

I believe during the technical conference we had specific discussion around that, and there's an interrogatory where you asked about that. And I specifically responded that the Orillia decision had nothing to do with the move to eliminate the distribution stations.

When we looked closer at the costs that were being allocated to the acquired utilities, what we noticed was that the amount of distribution stations that were being allocated was significantly higher than the actual distribution station asset costs for the acquireds. And we looked at that and said, does that seem right?

And when we looked at the operation of the acquireds, we thought, okay, the distribution stations really do provide more of a local service. I mean, in the future there may be some feeders that go outside the -- outside the acquired utility service territory. But right now, they provide a local service, very similar to the poles and the wires and the transformers that are within those acquired utilities.

So that's the driver for making that change. It had nothing to do with the Orillia decision. And what we arrive at, the 41 million, is a cost that we believe fairly captures two things: It captures the incremental costs. So if you go back to JT3.18-19 and you reference the 25.6 figure, I think you correctly pointed out that figure represents the only the incremental costs associated with acquiring the utilities.

The 41.2 that we end up allocating to them captures not only the incremental cost, it captures the fact that there’s upstream distribution facilities that are now being used to serve the acquired utilities. There are common shared facilities, things like operating centres, service centres, call centres, the meter services shop, our head office building, our IT and billing systems, those are all shared facilities that now we are allocating a share of those costs to the acquired customers per the Board's methodology, and we believe it's appropriate that they share in those costs and that's where you end up with the 41.2 million.

MR. SHEPHERD: And so the bottom line ends up being that your costs go up by 25.6 to serve these people, but you think that they should pay another 15.7 -- 15.6, sorry, as their share of the common costs, which basically reduces the rates for everybody else, right?

MR. ANDRE: Yes, that's right.

MR. SHEPHERD: Because otherwise, everybody else would have to pay.

MR. ANDRE: That's correct. To the extent we don't recover a share of those costs from the acquired customers, we’d be recovering from the other rate classes, that’s right.

MR. SHEPHERD: And the thing that happened between March and December is -- aside from the Orillia decision which you say has no bearing -- is that somebody had the bright idea to go look and see whether this was right?

MR. ANDRE: Yes. I mean, we were looking at those, you know, in preparation for the upcoming interrogatories, in preparation for the hearing. I mean, like we were looking at, you know, are these numbers correct.

MR. SHEPHERD: And so the people in Smiths Falls, for example, they pay the full amount of all these things. There's no adjustment for them, right?

MR. ANDRE: Yes, that's correct.

MR. SHEPHERD: And the people in Trenton, and the people in Thorold, they all pay the full -- I am trying to understand why, aside from the fact that the Board is getting tougher with you about acquireds, I am trying to understand why the cost allocation to these acquireds is fair and the cost allocation markedly different for the old acquireds is also fair. Which one is no longer fair?

MR. QUESNELLE: Mr. Shepherd, I think Mr. Vegh made an objection to that line as to whether or not the original acquired costs are fair. Those are acquired entities now. They are customers of Hydro One, and have been for twelve years.

I recognize -- I think it's valid to have the comparison of the methodology and point to the differences. But at this juncture, I think the evidence that has been given is that there was a conversation and there were Board decisions back in 2006.

MR. SHEPHERD: Mr. Chairman, if Mr. Andre answers my question that the current cost allocation is fair, then that's the end of it. By implication, the old one is unfair, but you're right, there's nothing we can do about it.

But if his answer is neither of them is fair, or there's a balance, or they’re fair in different ways, then I think this Board should hear it because that relates to these acquireds.

MR. QUESNELLE: In that context, Mr. Andre.

MR. ANDRE: I think the allocation to the three acquireds that we have now follows the Board's underlying principles that are in the cost allocation model. There are certain costs that are allocated based on number of customers and weighted number of bills, and that is the same as it always has been.

And then on top of that, we've adjusted -- we have made an adjustment to what the model would normally allocate to be consistent with the direction that the Board has provided with respect to setting rates for these three acquired classes as part of their MAAD decision.

MR. SHEPHERD: I wonder if you could turn to Exhibit K10.8, which is the materials from the Orillia motion. And I am looking at page 31, which is part of the Niagara-on-the-Lake analysis.

I am not going to ask you to agree with the analysis; I know there's lots of things you disagree with in it. But I am going to ask you about one statement in here. It's the last two bullets on page 31 -- does do you want to wait to get it up on the screen?

MR. ANDRE: I have it. It's not up on the screen; I don't know if we want to wait to bring it up on the screen.

MR. SHEPHERD: You can read those two bullets while we are waiting for it to get up on the screen, page 31 of K10.8. Sorry, page 31 of K10.8. There you go. And right at the bottom of the page, you see those last two bullets? So basically they have stated two sort of basic underlying rate principles, and I am going to ask you whether you agree with them. The first is, if ownership changes but the acquired service territory is merged with a lower-cost service territory then rates in the acquired territory should fall.

And then the second -- the last bullet is, if ownership changes but the acquired service territory is merged with a higher cost service territory, then the rates in the acquired territory will rise. This has occurred with the Hydro One acquisitions.

So do you agree that in principle that's correct?

MR. ANDRE: I think that's a very generic statement. And if -- the reference to rates would be if there was a single rate that would apply to a utility that averaged everything in that utility, in generic terms, yes, whenever you merge two things of different values the merged entity will always in principle come out at the average of the two, but that's an average rate for the -- all customers in the utility as a whole. That's not what we have here in terms of the rates of individual classes within the acquired utilities, and it doesn't take into account the cost allocation that happens in terms of allocating costs to individual classes within the utility.

So in terms of a generic statement, I don't disagree, but I don't think that accurately captures what's happening with the three acquired utilities that are part of this application.

MR. SHEPHERD: Well, that's right, right, because you have responded to that, to that problem, if you like, by saying, well, let's be more precise in our cost allocation, because not all of our assets are serving these guys, and let's work within the ranges of revenue-to-cost ratio so we can get their rates below what they would have been. And you have done that on purpose, right? You said so.

MR. ANDRE: I don't believe I said I have done it on purpose. I've talked about the cost allocation quite a bit already. With respect to the rate design, what I have talked about is that with respect to rate design we get them to within the Board-approved range. And to me, being within the Board-approved range is essentially charging them their cost to serve, because it is recognized that cost allocation isn't perfect, and the Board has set up a range from 85 to 115 or from 80 to 120 that it considers to be an acceptable representation of the cost to serve a particular class.

MR. SHEPHERD: So should this Board Panel assume that indefinitely going forward these acquired classes will have low revenue-to-cost ratios?

MR. ANDRE: I think those revenue-to-cost ratios will change as a function of the change in the total revenue requirement that Hydro One as a utility needs and the drivers of the allocation. So I wouldn't say -- like, there is not going to be a conscious attempt, Mr. Shepherd, to keep that ratio at .8. We will let the model do what it does in terms of allocating costs and comparing those to revenues, and then whatever revenue-to-cost ratio falls out of that, if it drops below 80 we will bring it back up to 80. If it climbs above 80 -- if it goes up then that's the ratio that we would leave it at. We wouldn't bring them back down to 80. As long as it's in within the range we would consider it acceptable.

MR. SHEPHERD: But on rate base and all the costs associated with rate base you have said that since you are not going to be keeping separate track of it, you are going to have these same adjustment factors essentially forever; right?

MR. ANDRE: I think we have put on the record that there may be a need to revisit it at some point in time in the far future, certainly not in the next five or ten years, but I wouldn't say forever. I think we have put on the record that there may be a need to review these adjustment factors at some point in the distant future.

MR. SHEPHERD: But the bottom line ends up being that these acquired customers have to bear some of the common costs of Hydro One, which they wouldn't otherwise have to bear, but you are keeping that under control with appropriate techniques, I am not disagreeing, you are keeping how much of the common costs, the non-incremental costs, they share, and only to that extent do your other customers benefit; right? By this acquisition.

MR. ANDRE: Right. And so for the common costs -- so let's be very clear -- the adjustment factors apply to those assets that we believe are local. When it comes to common costs, billing and those general admin costs, they are getting -- these new acquired classes are getting the same share on the same basis as all the classes.

So if it's number of customers, then the number of customers that they represent, if there's a, you know, a customer-service-related US of A that's based on number of customers, they will get the same share as all the other classes based on number of customers. The adjustment factors apply only to those assets that we believe are local and serve the local utilities. The other items, like shared costs, are shared equally among all classes.

MR. SHEPHERD: Well, yeah, except that you were very clear on Tuesday that a large amount of those costs are subject to the adjustment factor; right? Not only the direct costs associated with rate base but also OM&A are directly related to that allocation; right?

MR. ANDRE: Agreed. But I just wanted to make the point that the majority are associated with local assets, the maintaining the poles, the transformers, and the OM&A associated with that, but there is, as the allocation shows, there is not an insignificant amount of costs that are related to shared services, which is driving the number that you see, that is allocated to the acquired classes on the same basis as all other rate classes.

MR. SHEPHERD: Can you go to page 43? I am almost finished, Mr. Chairman, maybe two more minutes. Can you go to page 43 of that same exhibit, K10.8. And if you see on item number 4, the -- what the authors of this report say is the subsidization -- that is, the new customers coming in at lower incremental costs so that they are picking up some of the costs you are already spending -- the subsidization is hiding further inefficiencies of Hydro One. Basically, what I think their point is -- and I am going to ask you whether you agree with this -- is if by acquisitions you are able to get more people to share your costs, that artificially reduces your rates instead of actually controlling the costs; is that right?

MR. ANDRE: So Mr. Shepherd, I mean, we are towards the end of the report, and their reference to subsidization and inefficiencies, I can't comment on how they arrived at their quantification of the subsidization or how they defined efficiencies. I know you did provide this report, and I skimmed through it, but I don't know the underlying data, so I wouldn't hazard -- I wouldn't want to comment on their recommendations, because I don't really understand the basis for this report.

MR. SHEPHERD: I am not actually asking about their recommendation, I am asking about the principle. If you are able to keep rates down to at least some extent by doing acquisitions and therefore having lower incremental costs and having the new customers share some of your existing costs, is that not true that it reduces your need to actually reduce your costs because you are getting an artificial reduction through having more people share them. Isn't that right?

MR. ANDRE: No, I would disagree. I have been following the other panels, and I would think that they have been very clear about the steps that the company's taking to increase productivity and increase efficiencies, and nothing in what I have heard or what I am aware of in what they said relates to, we are relying on acquisitions to drive those productivity efficiencies. I think the evidence is very clear on that.

MR. SHEPHERD: Now, you did one acquisition, Hydro One Brampton, a long time ago, and you kept them in a separate company so that their local costs were actually ring-fenced; right?

MR. ANDRE: Yes, I am aware that we kept them as a separate company, and therefore they had their own rates. The basis and rationale for that, I wasn't privy to that.

MR. SHEPHERD: They actually had -- for all the time they were owned by Hydro One they actually had much lower rates than any of the Hydro One classes; isn't that right?

MR. ANDRE: Yeah, Hydro One Brampton had lower rates at the time that we acquired them. We kept them separate, and therefore, by virtue of the fact that they were kept separate they maintained those lower rates.

MR. SHEPHERD: So in order to achieve the Board's goal of ensuring that the costs for the acquireds reflect the costs to serve them, why wouldn't you just simply put them in a separate company, as you do these acquired, the three you have done, Orillia if it happens, Peterborough if it happens, all these various things? Why wouldn't you just put them in a separate company like Brampton so that you can ring-fence those costs? You will still have some shared costs, but that would do exactly what the Board told you, wouldn't it?

MR. ANDRE: I am not exactly sure that we are the right panel to speak to that. I am aware that trying to do that -- so keeping a different set of books, creating within our financial systems a different structure, requiring our field crews who would be in the field driving through Hydro One's service territory providing their service and then driving into what is an artificial boundary that exists within the financial system to say, okay, now I am in this other jurisdiction and now I've got to track my costs separately because these costs go to a different business, I think there are certain practical realities that would really limit our ability to efficiently integrate these utilities if we created a separate company.

MR. SHEPHERD: The problem is Brampton was big enough that it basically could have its own service centres and everything and be treated separately, whereas you couldn't do with that Norfolk or Haldimand because it's embedded within a whole bunch of other Hydro One territories, right?

MR. VEGH: Again sir, the witness is giving evidence on cost allocation, not the structure. I believe the structure of the acquisitions -- I don't know if they were addressed in the MAADs application; that's a completely different application.

But what they're addressing is how the costs are proposed to be allocated to these new rate classes, and they have given the reasons for taking this approach. And going back to old alternatives like Brampton again I don't think sheds much light on the appropriateness of the cost allocation or rate design for the acquired utilities in light of the Board's direction in applications with respect to those utilities.

MR. SHEPHERD: Mr. Chairman, the problem here is that these three companies are being -- these three service territories are being given a special deal. And what we are trying to explore is what's the solution to that.

Hydro One's proposed a solution. Let's have this special cost allocation deal for them, and let's set their rates in a certain way so that we can achieve the Board's results. We're saying, well, maybe there are other ways to do that. We are going to suggest in our final argument other ways to do that, one of which is to simply tell them don't buy anymore utilities. That will solve the problem.

But I think it's legitimate to ask would you have problems if you went the Brampton route, which did achieve the result that the Board wanted, in these cases.

MR. QUESNELLE: I think, from a cost allocation point of view, Mr. Vegh, this would be the panel that could describe how costs would be captured and used in the modelling, and also in the tracking of costs and I think Mr. Andre is talking about some of the barriers.

So I think that it is a model Mr. Shepherd is exploring, and I think Mr. Andre is well suited to respond.

MR. SHEPHERD: So the practical reality is that Brampton and Norfolk, let's say, are different because Brampton was self contained an Norfolk and Haldimand essentially are not. Maybe Woodstock might be a little bit more, but the others are not.

MR. ANDRE: As I have indicated, I think the assumptions around those acquisitions was that they would be integrated within Hydro One. We would generate efficiencies by having field crews that could service all of the service territory. We'd be able to operationally integrate those utilities.

So, you know, that's the underlying premise of why we acquired those utilities. I think to try to create separate companies like we did for Brampton, yes, that would be -- that would have a lot of attendant costs with that.

MR. SHEPHERD: Mr. Chairman, I have gone over my time and I appreciate your indulgence. Thank you very much.

MR. QUESNELLE: Thank you, Mr. Shepherd. Mr. McLeod?

CROSS-EXAMINATION BY MR. MCLEOD:

MR. McLEOD: Thank you, Mr. Chair. Good morning, panel. My name is Michael McLeod, and I am with the Quinte Manufacturers Association. So that's, I'm sure you, Belleville and Trenton; I like to put that out there all the time.

There's two areas of clarification I'd like to explore with you. The first one is the time study, and the second one is load forecasting and rate design with respect to manufacturing.

So on the time study, and we know that the Energy Board asked for a study of service charges back in EB-2013-0416, and you're undertaking the time study for the miscellaneous charges.

I just wanted to point out here, too, because this becomes important for us, the Board in its handbook to utility rate applications in October 13, 2016 -- I don't think we need to turn this up because I am just going to quote a sentence out of there -- dated October 16, 20167 -- October 13, 2016, I am sorry. In quotes:

"The utilities are expected to demonstrate value for money by delivering genuine benefits to customers in providing services in a manner which is responsive to customer preferences."

So with that in mind, could you just take me through the process you went through in the time study? Because we look at these things as being absolutely critical to the operation -- to manufacturing operations. And I know when I went through the evidence, I could see the six or seven sort of steps you went through in doing it. But could you just take me to how you actually did that to come up with the study results that we see? That would be very helpful.

MR. BOLDT: Yes, certainly. I was the lead on the time study, and just without going into it because it talks about in the back of the study are details and the forms that we created.

What we looked at was the -- we took a bottom-up approach on this study, being we knew the activities that needed to be studied based on the handbook. We brought resources from around the company into the meeting room that had a vision of the work that needed to be done.

We talked about being unbiased, how do you -- you know, you want to cherry-pick, for a lack of better words, the good ones, the bad ones, whatever. So we didn't want that. We wanted a true look at what the whole of the work we do today.

So we developed forms, the very high volume -- if you will, the customer care functions that were very high volume. What we did was we picked two days a week when we were doing those high volume activities, and we recorded all of them on Tuesdays and Thursdays. The worker actually filled in a piece of paper that when they started their work in the morning and they went right to the minute on the travel that it took them to get to the first site, the work during the site that they were there, and they recorded that and they ended when they were going to the next site to work.

And at the end of the day, they PDFed those files and they sent them into a tracking system where we had people track those activities.

The low-volume work, the things that were very -- we don't see many of them, we indicated to our field sources and anybody who was doing it that they were to be done a hundred percent of the time. And basically, they did the contact same thing with those entities; the time it took them to do the work, to travel and do the work, the costs and the travel time, and we added any material, any trucks that were there, whether it was large or small trucks and the appropriate vehicles, whether it was boats, whatever it may be, and that's what -- how we did the study with different forms.

Related to CIAs, which is another one that's been modified again with the five or six different types of CIAs. Different work groups in the organization do the

CIAs and what we did was we divided -- we don't need to go to the forms, but the forms are attached. And whether there were field visits involved in CIAs or different working groups, whether they were engineering people downtown or whether they were people in Barrie, they filled out different forms based on when the form B comes into the -- when a person applies for a generation connection, there were two forms, the administrative work there to get it into the system, and then it went to the appropriate other people who filled out their form, and then at the end of that, it came back to the administrative function and they had a separate form to fill out.

So we basically captured every minute that was being worked by an employee and/or the equipment and any material that they were using in the study.

MR. McLEOD: Was it just for that group -- let me back up a second. Has Hydro One done studies in any other parts of the corporation, or is it sort of -- is this the first time you've kind of done it in your area, for example?

MR. BOLDT: There is a reference, we had some -- I would have to go and check, but I believe it was our railway crossings, pipeline crossings, and -- did I say railway? Water, railway and pipelines, I think is what they were.

MR. McLEOD: Yes, I vaguely remember reading that.

MR. BOLDT: And that study was done in 2015. So in our study, there was -- some of them had no volume. They are very, very rare, and what we did was we looked back at a previous study and the hours that were in that study were accepted, and that's how we compiled the cost in those -- on those things, just updating the labour components and the equipment based on the old study.

MR. McLEOD: So the time study was built in-house, effectively, for your staff. Like, you didn't use an outside consultant to do this.

MR. BOLDT: No, we used an Elenchus consultant to make sure that we were on the right approach. We have an independent consultant that reviewed our material, reviewed our forms, and as we progressed through it at the end of it he gave us recommendations, which we took and we implemented to make sure that, you know -- the truth is when it's an in-house study of time and labour we brought the people in that were knowledgeable of the workers and what they were doing and that's how we did it.

MR. McLEOD: Okay. And just one other question related to that. So it's not a time-in-motion study, it was just a pure time study? So in other words, a time-motion study, for example, would be to say exactly -- there's the time you apply to do the piece of work, but inside that amount of time there's other bits of work that have to be done to build up that time, so it wasn't one of those kinds of studies. It wasn't that in-depth.

MR. BOLDT: I am unclear in what you just said, because of the activities. Like, we captured the true time that it took to do from cradle to grave of those individual jobs.

MR. McLEOD: Okay.

MR. BOLDT: And we captured every person along the way, every resource along the way.

MR. McLEOD: Okay. So I think what I am doing is getting down to that more granular stuff inside that period of time, that one hour that person took. You didn't go in and say, okay, to work my desk I did this, but I had to get up and go over there to get something else to come back and help me do that to help me build up that hour. So it's a very detailed, more granular -- so I am getting a sense that you didn't do that, it was just pure time, which is fine.

MR. BOLDT: No, I would disagree with that in the sense that if a person was getting in their truck and driving, the 10,000 samples that we had for, like, disconnects and reconnects, there would be obstacles in their way in driving, right, there was different weather, there was different locations, which we captured, but at the same time when they got to do the work at the site there would be different obstacles there.

So, you know, one might be very easy to go and do, and the other one, there may be obstacles, like fences. They may have to go back to their truck --

MR. McLEOD: Fair enough.

MR. BOLDT: -- so we had a very detailed look at all the possible things that we feel was in the study to cover their full -- to be able to do their work properly.

MR. McLEOD: Good. Okay. Thank you very much.

Just moving on to the load forecasting and rate design section here. Most of our members are Class B customers, and I have mentioned it in earlier panels. They want a closer relationship with the utility that they are working with, and some feel that they are getting a little bit lost in the general-service category, that the issues that may affect them in terms of service quality, power quality, and things like that are not always getting picked up. It doesn't mean they are not getting service locally. They are they are getting great service, and I have mentioned that before.

Is there a concern that -- and I think it has been touched on a couple times, and Mr. Shepherd was sort of hinting at it here -- as the utility, Hydro One, gets bigger and bigger -- it's becoming a massive utility now -- should we be concerned that our customers are kind of getting lost in the pool of big general-service customers? In other words, the specific issues that would be particular to their manufacturing situation and the things they do and produce -- and typically -- and I have mentioned this before -- they are a manufacturing hub, so they kind of feed each other in in certain circumstances -- are they going to get lost in this? Because the feeling is that they just become an account number and not something that really the utility should start paying attention to because they produce highly specialized products, they are just-in-time businesses, power is an essential service to them, and they are sort of missing that. So that goes to load forecasting so they know what's coming down the pipe, and the rate design, how they are designed.

Can you just respond to that? That would be helpful.

MR. ANDRE: I will offer it up to Mr. Alagheband if he wants to say something with respect to load forecasting. But Mr. McLeod, the one thing that popped to mind when you were speaking is that as a load forecasting and rate design group, the director of that group, we absolutely get lots of interaction with either account executives or customer-service staff. When they hear complaints or issues from customers like the ones that you are referring to, and if they feel that there is an issue there that could potentially be addressed by cost allocation or rate design or want to understand how cost allocation and rate design might be influencing those particular customers, we get inquiries like that all the time, and we respond as a group, as a cost allocation, rate design, and load forecasting group, we respond to those inquiries and look at whether there is something within the load forecasting or the rates that needs to be revisited in order to address those concerns.

So we are getting -- I mean, not directly, but through our account executives and our customer-service folks that deal with your clients.

MR. McLEOD: Okay. I think that's where part of our concern comes, because back in the customer engagement panel I think I mentioned about, the account executives -- there's thought that there'd be account executives assigned to accounts that are at the 2-megawatt level peak and are transmission connectible. Some of ours are and some of ours aren't. And they are looking for something a bit closer to their issues in their geographic area, and it doesn't apply across the entire province, and I am sure you guys know, and you have probably seen it, that manufacturers do different things in different parts of the province, and they have different needs when it comes to power.

So there isn't any thought right now that we need to kind of break this up, and I am using it as a general term, to focus maybe on more regional or zonal cost allocation that fits the geography and the nature of manufacturers or CNI customers in certain geographic areas. So there's no -- I am getting the sense there's no thought about that right now. And you wouldn't see that kind of thing coming, I don't suppose.

MR. ANDRE: If we saw them, if we heard issues, as I said, through our account executives or through our customer service, like, if customers that don't have account executives but they go through our call centre and raise issues through that forum, we would get that information. And if it's something that we as a company feel that needs to be addressed because perhaps the way the rates are set for general service -- large -- general service demand customers, the larger type customers or general service energy customers -- if we feel it's something that needs to be revisited we would typically go to the Board with those and raise those issues with the Board, and in fact, the Board is right now looking at whether there needs to be a change to the rate design for general service customers. They previously looked at residential customers. They are currently looking at whether there's changes required on the general service customers.

And so I think part of what drove that need to revisit it was the kind of issues that you looked at. But in terms of regional rates, no, you know, a utility, we use postage stamp rates, so when we develop rates for a class it applies to all customers in our service territory, and really that provides the benefit of sharing the costs among everybody, and, you know, it's arguable how you characterize what is fair, but, you know, if you didn't do that there would certainly be parts of our service territory that are much harder to reach, have much lower density, whose costs would go substantially up.

So, you know, the Board has adopted postage stamp rates within a utility, and that's the approach that we are taking. But I think your concerns, whether they are raised directly -- if it's something that we feel we can do within the company with respect to rates and load forecasting or if it's something that we feel needs to go through the Ontario Energy Board because it's broader industry-wide issue, those would be the two avenues that we would look at the issue at.

MR. McLEOD: Right. Thank you very much, panel. I appreciate that. And Mr. Chair, I was trying to keep tight to my time.

MR. QUESNELLE: Okay. Thank you, Mr. McLeod. Mr. Pollock.

CROSS-EXAMINATION BY MR. POLLOCK:

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

And good morning, witnesses. I have one line of questions today, and I think they will be for you, Mr. Boldt, and they are about external revenues, so unfortunately I think the questions will be a little bit complicated by the fact that they are updated this morning. Do I understand that correctly? The external revenue amounts were updated?

MR. BOLDT: Yes, that's correct.

MR. POLLOCK: So what I propose to do is if we could just clarify on the basis of the earlier evidence and then we can layer on the impact of the updates. Does that sound like a plan?

MR. BOLDT: Yes, let's try that.

MR. POLLOCK: Okay. So if we could go SEC 4, attachment 2, page 8, please. If we could just scroll down a bit.

So my colleague Ms. Blanchard asked an earlier panel about this figure and as I understand it, the figure is supposed to illustrate all of the factors or the drivers of non-actionable rate increases for 2018; is that correct?

MR. ANDRE: So I will give you the response, because I think the chart that you are pointing to is from a higher-level document. I think I've seen this chart in the context of business planning, which is really not specific to Mr. Boldt's area.

But, yes, this chart illustrates the different components that are driving the increase that's proposed in this rate application at a point in time. I know that there's been changes, but at that point in time, this illustrates the various components, that's correct.

MR. POLLOCK: Right, and we asked you in J1.4 what the teal box that .7 percent of the revenue impacts was. And I understand it, Mr. Boldt, you are co-owner of that undertaking response and essentially, you said it was external revenues, correct?

MR. BOLDT: Yes. The response says to look at external revenues, yes.

MR. POLLOCK: So that I understand the relationship, the figure in the exhibit previous, the reason that it's driving a rates increase would be if external revenues were trending downwards, correct? So the less external revenues you're collecting, the more you would need to collect in rates. That's the relationship, correct?

MR. BOLDT: Yes, external revenue offsets the rates, would reduce them.

MR. ANDRE: And if I could just add. So what you would be seeing there is the difference between other revenue, as was in our previous application and approved by the Board, so as it was currently approved for '17, and then other revenue as it's proposed in the current application.

So it would be the difference between other revenue as approved versus as proposed.

MR. POLLOCK: Okay. So could we go to Exhibit E.1, tab 1, schedule 2, page 2, please?

So, Mr. Boldt, you are also listed as a co-owner of this exhibit, and I note -- sorry, if we could just scroll up a little bit -- sorry, down a little bit. I want the see both, thank you.

So we have the total external revenue and other in the bottom row, and 52.7 is the 2017 approved amount. And then if we go to table 2, the total external revenue and other is 53.6.

So as I understand it, the external revenues are going up, so shouldn't that be driving rates downwards?

MR. BOLDT: Just so I understand your question, table 2 is for the test years 2018 to 2022. And the forecast, the total of this table, is made up of regulated revenues, unregulated revenues, and standard supply service charges.

The individual tables within the revenue exhibit break that out, but the forecasts that we have based on the volume that we see, the total revenue is going up.

MR. POLLOCK: So my question is specific back to the original figure that I brought you to. It seems that in that figure, other revenue impacts, and which I understood to be external revenues, are a factor that's driving rates upwards by .7 percent.

And my question to you is, if external revenues are in fact growing between 2017 and 2018, wouldn't that put a downward pressure on rates rather than requiring a .7 percent increase?

MR. QUESNELLE: Mr. Pollock, would it be okay if we had the original exhibit you requested back up?

MR. POLLOCK: Yes, absolutely; SEC 4, attachment 2, page 8. So while the witnesses are conferring, the teal box, the .7 percent for other revenue impacts, as I understood it was supposed to be driving a rate increase.

MR. QUESNELLE: Thank you.

MR. BOLDT: So I do agree that the external revenues are going up, and there could be other costs or other revenues that are affecting it that isn't seen it drive down.

MR. POLLOCK: Sorry, there's other things within external revenues, or are you saying there's other things in the category of other revenues aside from and apart from external revenues?

MR. ANDRE: If I could clarify, yes, you're right. So in principle, if other external revenues goes up, that should have a downward pressure. So I what I think that points to is that other revenue must include other things, other than external revenues.

And I think the best way to deal with that would be to take an undertaking just to clarify exactly what's in other revenues, because clearly it goes beyond just external revenues. There must be another component that's accounting for that.

MR. POLLOCK: Yes, if we could get an undertaking for that I would appreciate it.

MR. SIDLOFSKY: That will be J11.1.

UNDERTAKING NO. J11.1: TO CLARIFY THE "OTHER REVENUES", WHETHER IT INCLUDES MORE THAN EXTERNAL REVENUES

MR. POLLOCK: And specifically I am looking to -- because we already sort of asked this question once. But if you could break out everything that's in other revenues and if you could show me how they all an add up to .7 percent, I would appreciate it.

And then, to be fair to the witness, if you would like to explain how your updates this is morning might change anything we've just talked about, feel free.

MR. BOLDT: The updates this morning, let me just go here.

So referring to basically the -- before the update, what we had was our external revenues. And you can see those in a previous table, in the previous table.

The late payment charge was modified on Tuesday; we submitted another table there. And it basically in 2018 was reducing the revenue by $2.1 million.

By reducing or removing the rate codes that I spoke of in my opening statement, in 2018 it's reducing it by $341,000. And then by our proposal for rate codes 18, 19, 20 and 21, that we talked about referring back to the $65 and $185, that's reducing it by a further $1.3 million.

So the total difference that we are going to see in revenue is $3.754 million.

MR. POLLOCK: Okay, thank you very much. Those are my questions.

MR. QUESNELLE: Thank you, Mr. Pollock.

MS. GIRVAN: Sorry, can we get that in writing? I am having a hard time following, like an update to the evidence?

MR. QUESNELLE: Mr. Vegh, are we just going to rely on the transcript for the update, or will there be something filed?

MR. VEGH: I thought we would just rely on the transcript because that is in writing now, or it will be in writing when it's published. And there is -- the update to the evidence that was handed out this morning does address the updated figures.

MR. QUESNELLE: Do you have that, Ms. Girvan?

MS. GIRVAN: I guess I heard 341,000 and 1.3 million, but then I think I also heard 3 million and I was trying to reconcile those numbers.

MR. BOLDT: So the late payment charge which we submitted on Tuesday, the adjustment there was $2.1 million for 2018.

MS. GIRVAN: Okay.

MR. BOLDT: Removing the rate codes in my opening statement that I listed, it was $341,000.

MS. GIRVAN: Okay.

MR. BOLDT: And then the modification for our proposed charges for disconnects and reconnects during regular and after-hours, rather than our proposed fees versus reverting back to the now accepted fees at 65 and 185 is a difference of $1.304 million.

MS. GIRVAN: Okay. I see that now. So it's 3 --

MR. BOLDT: And now the total is 3.754.

MS. GIRVAN: Okay, thank you. That's a lot clearer to me now, thank you.

MR. RUBENSTEIN: I'm just wondering if Hydro One could re -- so put up what was up on the screen during Mr. Pollock's questions was the other revenue tables for the forecast of the test period. I was wondering if that could be updated, because I heard with respect to 2018 changes, but -- so I understand the proposal is it's five years of other revenues you're...

MR. BOLDT: Yes, Mr. Rubenstein, it is actually -- if you compare the two tables, the existing and the one we submitted this morning, it does go from 2018 to 2022. I am just stating the 2018 changes.

MR. QUESNELLE: Were you referring to the other exhibit that showed the graph?

MR. RUBENSTEIN: It was just sort of a simple, what the other revenues are. I was wondering if that just could be updated with the --

MR. POLLOCK: I think we are talking about Exhibit E1, tab 1, schedule 2, page 2, to be helpful.

MR. QUESNELLE: If you can put that up so we are all on literally the same page.

MR. BOLDT: Sorry, page 2 or Table 2?

MS. GIBBONS: Table 2.

MR. BOLDT: Yes, page 2, Table 2, right? So that's '18 to 2022.

MR. RUBENSTEIN: And so the information you provided is a sub-category within that.

MR. BOLDT: Yes, correct.

MR. RUBENSTEIN: I was wondering if Hydro One could just provide an update to table 2 so we know the --

MR. BOLDT: Yes, I think we could do that, yes.

MR. QUESNELLE: Mark that as an undertaking.

MR. SIDLOFSKY: J11.2.

UNDERTAKING NO. J11.2: TO PROVIDE AN UPDATE TO TABLE 2.

MR. QUESNELLE: Thank you. Mr. Woon.

MR. WOON: Thank you, Mr. Chair.

MR. QUESNELLE: Do you have a good line of sight there? Are you okay where you are, or --

MR. WOON: I think so. I think the witness panel can see me.

MR. QUESNELLE: Okay.

CROSS-EXAMINATION BY MR. WOON:

MR. WOON: Good morning to the witness panel. My name is Robert Woon. I am representing OSEA. My questions are just going to be focusing on the connection impact assessment charges.

So historically the company's had two rate charges for connection impact assessments, and this year they are proposing to add four more. For reference you can refer to Exhibit H1, schedule 2, tab 1, page 18 to 21.

MR. BOLDT: Sorry, can you repeat that again, please? Is it H1, tab 2, Schedule 3?

MR. WOON: H1, schedule 2, tab 1, page 18. Perfect, thank you.

So what I was saying was the company is now proposing four new rate codes for connection impact assessments. My understanding is that this was -- the key factor of this was a time study that was prepared by the company.

So my question was in terms of the time study, so the rate codes, they're primarily driven by how much staff time is taken by Hydro One; correct?

MR. BOLDT: Correct.

MR. WOON: And the time study indicated is educating what kind of how you develop that rate class; correct?

MR. BOLDT: Sorry, the time --

MR. WOON: So for example, the connection impact assessment for net metering, the time study looked at how long staff took to file that application or process that application. That's what is developing that rate --

MR. BOLDT: Correct, but what we looked at before the time study is the company that does -- the portion of the company that does the time studies -- or, sorry, does the CIAs, there was only two possible codes before, and what they did was they realized through different models and over time that they could break it into different costs because there was different labour components required to do different types of studies.

So what we did originally was we had took the opportunity based on the history and based on what they knew to say, let's break it into different types of CIAs and then study the costs or study the hours that it takes and the individuals to do the work to then compile a cost that reflects the work to do that individual study.

MR. WOON: Understood. So, for example, if we take -- let's stick with the net metering example, so the rate is $3,146.11, so to develop that you looked at how much staff time took to process application, right, and that was based on the time study. My understanding -- or my question is, how did you come across -- how did you develop that rate in terms of the time it took for the application? Was it the average time? Was it, you know, the maximum time staff took? How did you come to the hours taken to process that application?

MR. BOLDT: So like I stated earlier, in the time study there was a set of forms that relate to actually which CIA it's related to, so in this case the net metering, when the requests came into the organization, there's an administrative function, and then from there it's sent into CRM, to which the staff that are required to do the work on the net meter study, the CIA, they then record their time and what level of the organization -- like, what level of the pay scale they are at, and they did it on all the CIAs that came across and -- or came into the system. Those forms were uploaded into a database, and then what we did was we took an average of all the data that was received to do the CIAs based on that net metering study.

MR. WOON: So it's the average time it took to process the --

MR. BOLDT: It is, yes.

MR. WOON: So -- and my understanding -- this is going to be a set fee, so no matter how long the actual application takes, you are always going to charge that set rate; correct?

MR. BOLDT: Yes, that's correct. That's the proposal that we have broken it out into the different styles of CIAs, studied the time, and of these rates, comparable to a previous, the rates that were available, they have all been reduced, they have come down.

MR. WOON: So theoretically even if an application took less time to process, they would -- the person who is applying for the connection impact assessment would still be charged the standard rate of the 3,100 or 3,200.

MR. BOLDT: Yes. All applications will be charged the same fee.

MR. WOON: My next questions refer to the time it takes to actually get the assessments done. So I understand you have the 60 days under the Distribution System Code to get the applications done, and I think you reference in your application that you basically are near 99 to 100 percent meeting that 60-day deadline.

My question is, do you know what the average time it takes to actually process those applications? Is it always near that 60 days or the average time takes 30 or 40 days?

MR. BOLDT: I wouldn't be the right person to ask that.

MR. WOON: That's okay.

Mr. Chair, thank you, that's all my questions.

MR. QUESNELLE: Thank you, Mr. Woon.

Mr. Buonaguro, we will be breaking at about 10:45, so if you want to -- I know you are scheduled for longer than that, obviously, so if you want to find a natural break around that time that would be great.

CROSS-EXAMINATION BY MR. BUONAGURO:

MR. BUONAGURO: Okay. Thank you very much. I will shuffle around my order to try and come up with a discrete issue that we can do in the 15 minutes.

Good morning, panel. My name is Michael Buonaguro. I am counsel for the Balsam Lake Coalition, and I have some questions for you.

I have prepared an electronic version of a compendium to make it easy for whomever it is that's running the video presentation unit to put my references up, so that's -- there it is. BLC compendium for panel 7, and I assume that's need an exhibit number.

MR. SIDLOFSKY: That will be K11.2.

EXHIBIT NO. K11.2: BLC CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 7.

MR. BUONAGURO: And I may referring to some exhibit -- or to some documents that were included in our BLC compendium panel number 3, which was given Exhibit No. K4.5.

So I am going to do, because we're -- just before break, I am going to skip down to -- in BLC compendium number 7 the -- I believe it's the fourth document. It's called Undertaking J4.5. It's the third-last or the fourth-last page in the document. So I think it's page 8. That's right. Got a full page view, and then just scroll down. I'm not looking at that one. I'm looking at J4.5, which is further down in the document, I believe it's page 8 or page 9. There you go, thank you very much.

So this was an undertaking that panel 3 gave me in response to some questions about how the company put -- how the company formulated its proposal to the provincial government in support of what turned out to be the distribution rate protection plan.

And I was wondering if you could help me with what this means, and specifically I am looking at lines 16 to 20. It says:

> "Based on an analysis of overdue receivables for residential customers at 2016 year-end ..."

I can stop there. In relation to the total number which is further on of $88 million, can somebody explain to me what that means?

I can sort of put propositions to you, but it might be simpler if someone just explains to me what that represents.

MR. ANDRE: Mr. Buonaguro, I note that the undertaking response was provided by Mr. Merali, and I don't think anybody on this panel would have been involved in pulling that information.

On the face of it, it suggests that it's the information available for customers as of 2016 year-end. But beyond that, I don't think I can help you.

MR. BUONAGURO: So I am in a bit of a pickle, because if you don't understand it, I am definitely not going to understand it.

MR. ANDRE: I'm sorry. Like, I would take that on the face of it, that they've pulled information on overdue receivables as of 2016 year-end. But in terms of what overdue receivables are, that's -- you know, nobody in my group deals with the collection of overdue receivables, so we wouldn't have information on the details of that.

MR. BUONAGURO: Right. So what I am looking for is a way to understand this undertaking response, and I am looking to the Board Panel if there's something we can do here.

I note that this panel, for example, was given a series of written questions by VECC on Tuesday to provide answers to, rather than taking up Board time. Given how this undertaking came to me, I would humbly ask the Board for a similar concession in order to understand what this means.

I can speak more about how this came -- how this undertaking came about, if you like. But maybe if the company is agreeable, then we can just agree that I will provide some written questions about this undertaking. Otherwise, I can explain more why I think it's appropriate.

MR. QUESNELLE: Mr. Vegh?

MR. VEGH: Just to clarify, I think with respect to VECC's questions, it wasn't so much a concession but a way to more efficiently deal with a number of technical questions. It could have been objected that these questions looked a lot more like interrogatories than what we would proceed with in the oral hearing.

But I think that if Mr. Buonaguro puts his clarification -- if he can state the clarification requests on the record, we can see if the previous panel can provide that clarification. But I don't really see the value in another stage of interrogatories with respect to undertaking responses.

MR. QUESNELLE: Could you simply state it on the record, Mr. Buonaguro?

MR. BUONAGURO: Well, I could ...

MR. QUESNELLE: Do you have a series of questions?

MR. BRETT: I could try. I mean the way -- if I can give an example. It says here:

> "Based on analysis of overdue receivables for residential customers at 2016 year end."

If I had a witness here, I would put to them so what does that mean? Does that mean as of December 31st, 2016, you were owed $84 million from customers from outstanding bills? Presumably, the answer would be yes or no.

And then I would go on, well, what billing cycle is that based on, for example, for R1 and R2 and urban customers that would be their -- presumably from their December bill, whereas for the seasonal customers, they're on a quarterly billing cycle, as I understand it, and therefore their bill would have been from September; so we are talking about three months versus one month overdue.

I would be wanting to understand how many customers in each class were overdue, because if what they are talking about is a point in time billing overdue or accounts receivable for everybody, that could mean customers who were three months overdue on their bills, but actually only have a handful of customers, or it could be more than that. It would have been much, much easier to have done this with a panel.

MR. QUESNELLE: Understood. Perhaps you could go back and -- how is it you came about being in receipt of this?

MR. BUONAGURO: So I asked -- if you look at the question at the top of the undertaking, it says to provide an analysis that was done in 2017 in support of the proposal with respect to prioritization of customers between R1 and R2 class and resulting in the conclusion by Hydro One to exclude seasonal customers.

And if you recall panel 3, I included the full transcript of my tech conference exchange with this particular witness, Mr. Merali, where I asked several times in several different ways to explain to me how it is that they decided to exclude seasonal customers from that particular proposal.

MR. QUESNELLE: I recall the exchange, yes.

MR. BUONAGURO: Yes, and in the tech conference I got -- if you look at lines 25 and 26, I got that answer in slightly different ways. I never got anything close to the answer that's from 16 to 20.

So, I mean, it obviously would have been appropriate in the technical conference to follow-up on this type of answer. But I didn't get that opportunity, because I never got this answer.

And then we had the oral hearing on panel 3 and I pursued it again several times, and there was an objection by Mr. Nettleton to the whole line of questioning, and the Board ruled on that, if I can call it that, and I finally got the suggestion that there was this type of analysis for the first time, and I got it on Monday, this analysis, and I don't understand what it means and I there's -- if it comes close to being what I think it is, I think there are major holes on it, but I can't follow-up without asking questions.

MR. QUESNELLE: Do you have any proposals, Mr. Vegh?

MR. VEGH: Well, we do want to be helpful to the Panel, and if the Panel from that introduction would find value in some questions being put in writing with respect -- factual questions, not argumentative, with respect to the facts underlying undertaking J4.5, that may be an effective way to then provide this information to Mr. Merali, that request.

I'd have to have more context from the transcript, et cetera. But if it is a factual clarification of what's being requested, perhaps we could forward to that Mr. Merali, and we can provide an answer in writing.

MR. QUESNELLE: That would be appreciated. I recognize your concern, and we certainly don't want to make this routine. But I think Mr. Buonaguro has certainly convinced me he has made attempts to get this level of detail, and it's come after the opportunity has gone to put it to the witnesses.

So I think that if that could be facilitated in writing, that would be appreciated.

MR. VEGH: Thank you, sir.

MR. BUONAGURO: Thank you very much, I appreciate it. So I'll just -- I think we're about 5 minutes before the break, so I'll just start briefly with sort of an overview question.

MR. SIDLOFSKY: Sorry to interrupt you, Mr. Buonaguro, but it sounds like that was an undertaking.

MR. BUONAGURO: Sure, thank you.

MR. SIDLOFSKY: J11.3.

MR. BUONAGURO: I am too trusting.

MR. SIDLOFSKY: I will help you with that. J11.3.

UNDERTAKING NO. J11.3: TO PROVIDE AN ANALYSIS THAT WAS DONE IN 2017 IN SUPPORT OF THE PROPOSAL WITH RESPECT TO PRIORITIZATION OF CUSTOMERS BETWEEN R1 AND R2 CLASS AND RESULTING IN THE CONCLUSION BY HYDRO ONE TO EXCLUDE SEASONAL CUSTOMERS.

MR. QUESNELLE: Mr. Buonaguro, I take it you will be providing written questions and also, I guess, Mr. Merali can obviously rely on the conversation on the transcript as well, thank you.

MR. BUONAGURO: Thank you very much. So just to kick off before the break, if you go to the compendium for panel 7 and the first document, so that's the document you have on the screen, and this is from Exhibit H1, tab 1, schedule 1, page 9.

And I did read the transcript from Tuesday, and I did get here in time to hear some of Mr. Andre's responses to Mr. Shepherd's questions. And I think -- so part of what I was going to ask has been covered off, but I just wanted to confirm.

What are included here at table 5 from the evidence are the revenue to cost ratios and class revenue recovery from 2017 to 2018, and I have highlighted in my compendium the Board ranges.

I am assuming this is for Mr. Andre. You spoke several times about the acceptable ranges of revenue cost ratios for rates from a cost allocation perspective. And as I understood your conversation with Mr. Shepherd, both on Tuesday and today, my understanding is that from a purely cost allocation point of view, if the company charges a class in rates in revenue -- a rate that recovers anywhere between -- in this case, residential cost is between 85 per cent and 115 of the costs that have been allocated to them through the model.

From a cost allocation point of view, that means that they are being charged an appropriate amount?

MR. ANDRE: Yes, that would be our position that, you know, as long as the revenue-to-cost ratio falls within that range the Board doesn't require any adjustments to be made in terms of shifting revenue from one class to the other.

MR. BUONAGURO: From the point of view of an appropriate allocation of costs?

MR. ANDRE: Again, yeah, the cost allocation model is not an exact science, as I have said before, and so if it's within that range the Board, as I have said, doesn't require a utility to make any adjustment. It considers that to be an acceptable range of revenue-to-cost ratios for, in this case, the residential classes that you've highlighted.

MR. BUONAGURO: And then on Tuesday -- and I will give you a reference just from page 150 of the transcript, so I guess that's Volume 10 -- you went on to say when you're making delivered changes to the revenue-to-cost ratio, so when you are adjusting rates to increase or degrees the revenue-to-cost ratios, you call that -- those are changes that are made at the rate design phase.

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: And that the Board might have various reasons for that -- for doing that, one of the reasons being that a particular rate falls outside the acceptable range, and I put acceptable in air quotes.

MR. ANDRE: Yeah, the Board -- I mean, the Board has specified the ranges, so the utility would then propose if it's, you know -- to follow the Board's guidelines it would propose moving the revenue-to-cost ratios to within the range, you know, for review by the Board. And -- yeah.

MR. BUONAGURO: Right. And then I am assuming one of the concerns when you are moving -- at the rate design phase, when you are moving revenue-to-cost ratios around, one of the things you are looking at are rate impacts, because anytime you move somebody up in revenue-to-cost ratios there could be an impact, and same thing when you are moving people down.

MR. ANDRE: Yes, so we would, you know -- an adjustment to move revenue-to-cost ratios up would mean that there's revenue available to reduce the revenue-to-cost ratio for those classes who is have the highest revenue-to-cost ratios, and then we would calculate the bill impacts for all classes at the resulting revenue-to-cost ratio that is being proposed.

MR. BUONAGURO: Thank you. That's an opportune time to break.

MR. QUESNELLE: Thank you, Mr. Buonaguro. Let's break until five after 11:00

--- Recess taken at 10:48 a.m.

--- On resuming at 11:09 a.m.

MR. QUESNELLE: Thank you, please be seated. Okay, Mr. Buonaguro, you can resume at your will.

MR. BUONAGURO: Thank you very much. I should apologize to the witness panel. I am usually not this far to the left, so don't take anything from it. I am usually much more central.

MR. QUESNELLE: We were all talking about it at the break.

MR. BUONAGURO: That's what I get for coming in late.

So I am going to take you to the second document in compendium 7, it's undertaking JT3.23. And by way of background, this is -- it refers to an undertaking. So we had originally asked for this type of analysis in Exhibit I, tab 49, schedule BLC.5, part B. So this originated in an interrogatory, and the interrogatory response, the company refused because of the effort that was involved in it, if I can summarize.

I followed up in the tech conference and asked the company to reconsider, and the company was able to provide this undertaking sometime after most of the undertakings were in to try and help out, so I appreciate that.

The original undertaking -- so basically, the undertaking was to run a cost allocation run where, from the seasonal class, the seasonal members that would be classified as urban would be moved to the urban class, the seasonal customers that were labelled R1 would be moved into the R1 class, and the seasonal customers that were in R2 would be left in the seasonal class, and how does that look like.

Now, when I asked the original question, I had asked you to keep all of the allocation factors for the seasonal class constant and to keep the proposed fixed and variable charges constant to see what happens.

And in your response, you say that that -- part of that was inappropriate. Basically, you said we weren't going to keep the seasonal weightings and allocation factors and so on constant; we were going to redo it to reflect the characteristics of the remaining seasonal R2 customers, correct?

MR. ANDRE: Yes, that's correct. That's -- we provided that response in the updated undertaking response.

MR. BUONAGURO: And my understanding would be that because I asked you to freeze, if I can call it that, the fixed and variable charges that you're proposing for that class, changing the allocation factors in the way that you describe in the interrogatory, the effect would be to change the resulting revenue to cost ratio, assuming there was a material difference in the cost to be allocated to that class, but it doesn't change -- it obviously doesn't change the rates since I asked you to freeze them, right?

So instead of -- and if we go to the actual answer, you get a resulting revenue to cost ratio of 86 percent based on the parameters that you put in. That 86 percent would be something different if you had done what I asked you to do, but that would be the major effect?

MR. ANDRE: Sorry, let me just have a look, I am not exactly sure with respect to what you're asking, because I don't know that -- just give us a sec.

So, Mr. Buonaguro, I agreed with what you were saying in terms of for cost allocation purposes. I mean, for cost allocation a class that consisted of R1 and R2 customers take a simple thing like their density, the density of customers would have been one thing.

And if you take out the higher density R1, the customers that are remaining in the seasonal class, in this case the R2 seasonal customers, would obviously not have the same density.

So from a cost allocation perspective, there were a number of cost allocation weighting factors where we would have said, no, the weighting factors for a new season until class that included just the R2 customers would be different than a seasonal class that included R2 and R1 and a very small amount of UR. So I agree with that point.

I don't recall any commitment with respect to the rate design, and that's what I was just trying to confirm. I think from a rate design perspective, we just followed the normal rate design.

MR. BUONAGURO: Oh, okay.

MR. ANDRE: We didn't -- I can't recall now if the approach was to keep the same fixed to revenue -- fixed to variable revenue split, or whether we kept the same fixed charge. But there was no, you know, with respect to revenue to cost ratios, that's completely flexible.

MR. BUONAGURO: I can you tell you that in the original IR, which was never answered until after the tech conference, I had asked to keep the fixed and variable charges in the same amounts. And the only reason I did that was I wanted to see what kind of shortfalls were created when you moved everybody out, and I was going to ask you why you didn't do that in your answer. But now I understand that you knew you didn't do it in the answer, so that's a slight difference from what I asked.

That's fair enough. Now I understand what you have done here is you've ...

MR. ANDRE: Kept the same ratio.

MR. BUONAGURO: You kept the same fixed variable ratio.

MR. ANDRE: Right.

MR. BUONAGURO: Okay, fair enough, thank you very much.

Now, as an example, what I -- the way I asked you to do it would have maintained a density factor of 3.6 for the seasonal class, and instead you say you used all the R2 factors except for one, which I'll ask you about in a second. Instead you would have used the R2 factor of 4.8 for the density factor.

MR. ANDRE: Right, that's correct.

MR. BUONAGURO: Okay.

MR. ANDRE: So a seasonal class that includes some, you know, some higher density seasonal customers and some lower density seasonal customers would have had the -- the blended density factor would have been 3.4.

But if you take out those higher density customers, then the density weight that most closely approximates a seasonal class that consists just of R2 customers would be the same weight as the R2 class.

MR. BUONAGURO: Thank you, thank you. And then you did make -- you said you made one change. So there's one -- from a cost allocation weightings factor and density factors and so on, there's one material difference, as I understand it, between the R2 class and the seasonal class with only R2 customers in it, and that was the meter weightings, correct -- sorry the meter reading?

MR. ANDRE: Correct.

MR. BUONAGURO: And I just wanted to confirm. Did you use the factor that is already in the seasonal class, or did you create some new factor? I wasn't sure from what you wrote.

MR. ANDRE: Your first assumption. We used the meter reading weighting factor that currently exists for seasonal class.

MR. BUONAGURO: I apologize these are somewhat technical questions that would have been better for a technical conference. But again, it's the way the interrogatory came in front of me that I have to ask the questions now, so I apologize.

Now, if we take a look at that - the actual allocation, I actually compared it. So if you go to the next, the next one is the most -- as I understand it, the most up to date version from the filing. And you'll see I highlighted the total revenue requirement as sort of a sanity check to make sure that it's like for like.

So what's -- the answer to the undertaking is based on the same revenue requirement and other factors that are in your application as filed, the current application, notwithstanding any changes that have been proposed today and I think there has been some.

So they are like for like, though?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: Okay, thank you. And if we look at the original one, this is the one from the evidence and I have a printout for me to help myself, but even I can't read it.

MR. ANDRE: Perhaps we can zoom up the version that's on the screen.

MR. BUONAGURO: Yes. So the one from the evidence is Exhibit H1, tab 1, schedule 2, and I just have a few questions on that.

If we go down to the box at the bottom that's sort of a summary of the fixed charges and the movement of fixed charges -- yes, there it is. Am I right that -- just a couple questions. Am I right that when we look at the 2018 all fixed charge, that's essentially -- that's what the fixed charge would be if you went to an all fixed charge, obviously, right?

MR. ANDRE: Yes, that's correct. So if instead of having a fixed and variable component in 2018, if it was all fixed, that's the numbers that you would see there.

MR. BUONAGURO: And as a -- I think it also serves as a proxy for an average rate impact because of -- I mean, if you were to collect from the average consumer in a particular rate class, in those rate classes, so the average are two customers having the average consumption would have a bill of $130.02, notwithstanding DRP and RRRPS funding?

MR. ANDRE: Yes.

MR. BUONAGURO: That's generally true. It's a proxy.

MR. ANDRE: Yes, the average consumption for the class. So if you divided the consumption of the class by the number of customers and that's what we call the average, then, yes, that would be the amount --

MR. BUONAGURO: It may not be the typical customer, may not be the median --

MR. ANDRE: Correct.

MR. BUONAGURO: -- but it's the average. Just for comparison, thank you.

Now, looking over at the 2018 proposed fixed charges -- and I ask about this because in an interrogatory to us, so at I.5.1.BLC.7 I asked what the consequences would be to R1 and R2 customers if the revenue-to-cost ratios were increased. I made the assumption that they would have no rate impact because of the DRP, the distribution rate protection plan, and the answer was, well, some of the low-volume would, and that confused me, because my understanding is that the -- if you can confirm subject to check -- that the DRP cap for this rate filing is $36.43. Does that sound right?

MR. ANDRE: That was the amount at the time the application was filed, yes.

MR. BUONAGURO: Right. And it will go up. It will go up sometime this year. It probably goes up.

MR. ANDRE: There was -- that was recently issued, like, a couple weeks ago, and it has gone up by a margin amount, 43 cents, so the minimum amount is available --

MR. BUONAGURO: Oh. Okay. Sorry.

MR. ANDRE: -- and it is a small increase, yes.

MR. BUONAGURO: Okay. So -- but if you look at the 2018 proposed fixed charges for the R1 and R2 classes, which are the classes that get the distribution rate protection, both of the fixed charges for those -- proposed fixed charges for those classes are above the DRP cap, so wouldn't that -- isn't it true then that if you increase the revenue-to-cost ratios for R1 and R2 anybody in those classes that's eligible for rate protection would see no effect on their bill, because the fixed charge is already over the DRP cap.

MR. ANDRE: Yes, I see what you are referring to, so you are saying that the fixed charge that's proposed in 2018 for the R1 classes is $37.56, and that is above the DRP protection amount, and therefore regardless of the volume they are consuming they would be lowered down to 36.43, so, yes, I would agree with your statement.

MR. BUONAGURO: Right, thank you.

Now, you had already answered part of this question, but if you go back to the original -- sorry, the answer to the undertaking, which was -- yes -- no, that was it. Thank you.

You had already answered my question in part, where you actually didn't hold the fixed charge in volumetric charges for the new -- I will call it the new seasonal class at the rate at which you are proposing. There are some slight changes in there; right? A slight increase, I think.

MR. ANDRE: Sorry, Mr. Buonaguro, could you ask your question again?

MR. BUONAGURO: Sorry. So if you look at the fixed charge, I have highlighted the column, fixed charge dollars per month for the new seasonal class 40.77, and you compare that to the original -- the original proposal. So if you go down to the original, the original was 40.52. So you have slightly increased the fixed charge by about 20 cents?

MR. ANDRE: Yes, so the increase required to the revenue requirement when you move the R1 customers -- sorry, the seasonal customers to the R1 class, it changes the revenue that's collected from each class, and so we would have -- we wouldn't have been, like I said, attempting to hold the fixed charge constant, we would have been applying whatever the fixed to variable split was to the new revenue that's to be collected from this scenario where it says "seasonal R2 group of customers."

MR. BUONAGURO: All right. I think I am starting to understand as you're talking what happened then, so notwithstanding the fact that you didn't do precisely what I asked you to do, I am not faulting you for it, I understand, so -- not intentional. But the reason that you end up -- I'm assuming that the reason you come up with an

86 percent revenue-to-cost ratio for the new seasonal class is that you're -- it's a function of escalating from the revenue we're collecting from those customers in 2017 and doing sort of your normal escalation, and that just pops out at 86 percent revenue-to-cost ratio.

MR. ANDRE: Yes, that's exactly right --

MR. BUONAGURO: All right.

MR. ANDRE: -- you take the revenue that would have been collected from the seasonal R2 customers at the rates that they were paying in '17 and then you escalate it based on the revenue deficiency, and that same increase across all classes per the Board's model when there is a revenue deficiency, it gets applied equally to all rate classes. So this number, this 85, is a -- falls out of the cost allocation model.

MR. BUONAGURO: Right. So from a cost allocation perspective -- well, first, as we talked about, you actually went in and fixed the new seasonal rate class, as I proposed it, only including seasonal R2s, so that it has proper allocators and weightings and such from your perspective?

MR. ANDRE: Yes, so we would have adjusted -- Mr. Alagheband's group would have provided the load forecast for just the R2 seasonal, and we would have moved the load associated with R1 seasonal and the UR, the very small amount of UR seasonal to the other classes, and we would have developed a new coincident peak allocation factor. So, yes, that's what we did.

MR. BUONAGURO: And the second part of that, from a -- and I didn't ask you to do it this way, but as it turns out, the way you have done it, you ended up with an 86 percent revenue-cost ratio which falls within the acceptable ranges for residential rate classes?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: Now, if you're looking at the box -- and I guess we should look at the box for the undertaking, so we are already there -- just -- and this won't be precise, but if we are looking at what's happening to the customers that under this scenario are moving out of the seasonal class and are moving to in this case UR and R1, the average under 2018 all fixed charge -- and we assume that's an average customer -- the average UR customer, if they were using an average amount of volumetric -- an average throughput per month, would be going from a charge of $63.23 per month to just under $34 per month? It will be slightly different, because I am using the seasonal R2 as the -- we could go back to the other seasonal class and get the more precise number, but it's a significant decrease in their rates.

MR. ANDRE: Yes, if -- a seasonal customer that's in UR -- and just to be clear, that's only about 300 out of our 160-some-odd-thousand seasonal customers. There's only about 300 that would go to the UR class, so we're talking about a very small number.

MR. BUONAGURO: Right.

MR. ANDRE: But, yes, their fixed charge would drop considerably in moving to the UR class.

MR. BUONAGURO: And the actual -- what they would actually experience depends on their actual throughput, so some of the customers that are high-volume might actually get more of a drop, because they are going from a very high variable charge in the seasonal class to a much lower one in the UR class.

MR. ANDRE: Yes, that would be correct.

MR. BUONAGURO: Right. And then again, the customers that would be moving from the seasonal class to the R1 class, the average would be a drop of $6 per month or so? And that's more. There's about 70- or 80,000 customers in that class --

MR. ANDRE: Yes, yes.

MR. BUONAGURO: -- that would have that experience? And again, the customers that are moving from high-volume -- they're high-volume and moving from seasonal to R2 -- would get -- the gap would be more, they would be saving more money in the initial stages as long as there is still a volumetric charge?

MR. ANDRE: Right. And so -- you are correct, Mr. Buonaguro. But if I could just add, of course, so these, when we have been talking about these reductions in the revenue that's collected from these seasonal customers when they move to the R1, I just wanted to make it clear that that less revenue that you get from the seasonal customers has to be made up by other classes. So when you look at the cost allocation rate design, I am sure you have noticed, Mr. Buonaguro, all of the other classes, everybody pays 1.1 percent more in their rates to accommodate, to make up for the fact that lower rates are being paid for by the group of seasonal customers that move to R1 and those very small amount of seasonal customers that move to UR. Everybody else pays 1.1 percent more under the scenario that we ran for you, Mr. Buonaguro.

MR. BUONAGURO: Right. So instead of -- let me put it this way. Instead of the seasonal R2s, the shortfall, as it's currently proposed, is being paid for by seasonal R1s and seasonal URs and under this second proposal is being paid for by everybody. Is that what happens?

MR. ANDRE: What do you mean, under --

MR. BUONAGURO: To the extent that there is a shortfall in the revenue collected from R2 seasonal customers under the existing seasonal class, it's picked up for by -- it's picked up by the UR seasonals and the R1 seasonals that are in the same rate class with them. And when you move the UR seasonals and the R1 seasonals out of the rate class and you have to make up the revenue shortfall it gets spread out over all the classes. I think that's all you just said.

MR. ANDRE: Yeah, I don't know if it's so much UR and R1. When they are together as a group, there's a large portion of revenue because, as you pointed out, there's a fairly high variable charge, so when they are all together in one seasonal class, that additional revenue is really being made up more by, I would say, the higher-volume seasonal customers, as opposed to saying it's the R1 and R2. It would be the higher-volume seasonal customers, even if they are in the R2 class.

MR. BUONAGURO: Fair enough.

MR. ANDRE: Those are the ones that are currently...

MR. BUONAGURO: But it includes UR and R1 customers.

MR. ANDRE: It would include those, yes, high volume customers.

MR. BUONAGURO: And I think if you go over to -- if you go over to the, I think it's the last page of the compendium -- yes, that's it.

So if you look at the table there and look at density factors -- so this is Exhibit I, tab 49, schedule BLC.6, page 2 of 2, and I am looking at the answer to part A.

When you look at under density factors, density factor 1 for UR, density factor 1.9 for R1, and density factor 4.8 for R2, those are the actual density factors for those classes, correct?

MR. ANDRE: Yes, those were the values determined per the study that was done.

MR. BUONAGURO: Right. And the seasonal density factor in the table, which is 3.47, isn't the actual density factor that you used for the seasonal class. That actual factor is 3.6, right?

MR. ANDRE: Yes, that's correct. The study that looked at developing the density factor for all of our rate classes had points on the chart for UR, R1 and R2, and then there was a graph that interpolated the value for the seasonal class based on a curve, a best-fit curve.

MR. BUONAGURO: Thank you. And the reason I brought you here, because of the conversation we just had, was to point out that when you moved -- I assume that when you moved, for example, R1 seasonal customers out of the seasonal class and into R1, they went from attracting costs at a 3.6 density factor to a 1.9 density factor, right?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: So those customers are attracting less costs when they go to R1?

MR. ANDRE: That's correct.

MR. BUONAGURO: And that factors into how much they pay as an R1 customer?

MR. ANDRE: That factors into how much the class pays as an R1 class, yes.

MR. BUONAGURO: And the same thing goes for UR?

MR. ANDRE: Correct.

MR. BUONAGURO: And also -- I think we already talked about it, when you moved -- sorry, when you reconstructed the seasonal class to reflect the characteristics of the R2 seasonal customers that were left in it, you used a factor of 4.8?

MR. ANDRE: That's correct.

MR. BUONAGURO: And then what I've proposed here is a different way of arriving at the density factor for the seasonal class for how ever long it remains intact, so if you are keeping all these customers in -- I have suggested as a possibility and I wanted to see what happened if you weighted the cost, what would the effect be.

So what you've done here is you've taken the density factors that each of these groups of customers would experience in their -- if I could call it their true rate classes if the seasonal class was eliminated, and weighted them, you've come up with a factor of 3.47, right?

MR. ANDRE: Yes, that's if we weighted the -- if the density factor for the seasonal class was calculated on the basis that you had suggested, which was just weighting based on the number of customers that are in R1 and R2, but as I indicated the original study didn't use a linear interpolation between R1 and R2. It had a non-linear trend line that was developed from the study that derived the density factors.

So in effect, you are saying if you did a linear interpolation but the 3.6 was based on a non-linear interpretation per the study.

MR. BUONAGURO: Right.

MR. ANDRE: So that's the one thing. The other thing I would point out is that even with the adjustment that you're suggesting there, that would change the cost that would get allocated to the class, but it wouldn't change the revenue to cost ratio such that it would fall out of the range.

So it would have no impact on the rates that you ultimately charged to the class. It would just show that, you know, from a revenue to cost ratio perspective, they have a slightly different number. But it wouldn't impact the rates that the seasonal class would pay, even if we made the change that you are suggesting.

MR. BRETT: Thank you. I think what you are saying there is -- we can use the actual numbers. Right now, you are proposing a revenue cost ratio of 1.09 for the seasonal rate class, I think that's right. I will below it up myself.

MR. ANDRE: Yes, I think that sounds correct.

MR. BUONAGURO: Right. And if you were to -- what you are saying is if you were to change the methodology for determining the density factor for the seasonal class by mapping, on a weighted basis, the density factors that those customers would experience in the UR, R1 and R2 classes, and that brought the density factor down to 3.47, that would allocate fewer costs to the seasonal class, and that would change the 1.09 revenue cost ratio. It would move it up, and I think it moves up to 1.01, or 1.11 or 1.12, something in that range. It moved it up, and that's the point -- yes.

MR. ANDRE: So it would definitely be below 1.15.

MR. BUONAGURO: So you are saying that in the normal course, if somebody's over 1.15 in the residential classes, you would then almost automatically take steps to reduce it, right?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: There's a flip side to that, which is that if other classes are moving up and there's excess revenue to bring other rate classes down, you start with the rate classes that are the furthest from 1, right?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: So if that happens in this case, if there's movement from classes that are below 1 moving up, and you've now increased the revenue to cost ratio for this class in theory from 1.09 to 1.12, or 1.11, whatever it is, it would experience -- it would actually attract more of the excess revenue in reducing its rates.

MR. ANDRE: Yes. Yes, I understand what you are saying and I would agree with that. If there's revenue to be shifted, the classes that have the highest revenue to cost ratios would benefit from that revenue shifting.

So using a linear interpretation, which is not consistent with how the density factor -- I just want to stress that because there was a study that was put together, and density factors were developed and proposed as part of that study and as I have said before, the 3.6 reflects a non-linear interpolation which was the best-fit curve for how the density factors change among the different classes.

MR. BUONAGURO: I think you mis-spoke. You said 1.6; I think you meant 3.6.

MR. ANDRE: Yes, I did.

MR. BUONAGURO: Is there anything fundamentally wrong with the weighting proposal, other than the fact that you did it different way?

MR. ANDRE: It would be inconsistent with the study that was used to derive the original factors.

MR. BUONAGURO: Okay. I want to take you briefly to -- I have got papers all over my desk here. I get a little confused because of where I am sitting.

I want to take you to compendium 3 briefly. So this is the compendium that -- the BLC compendium for panel 3, I should say.

MR. VEGH: I am not sure the panel has that compendium.

MR. ANDRE: It's on the screen.

MR. BUONAGURO: I want to start with just one cite that will be on the screen. I highlighted and we talked about it briefly, and I think panel 3 actually referred this panel to it.

So this is -- if you go to the bookmarks, this is the third document, the last -- your bookmark doesn't show up there, I'm sorry.

If you go to the third document, page 13, this is the updated report on the elimination of the seasonal class in EB-2013-0416 and EB-2016-0315. So past this document, so next, past this document, thank you. My apologies, there used to be bookmarks.

And then page 13 of the attached document to this report. There it is, thank you very much.

So I think I gave the full cite; this is the third document in the BLC compendium for panel 3. So this is an excerpt from the updated report on the elimination of the seasonal class and I think, Mr. Andre, you were involved in the preparation of this.

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: So I put this quote here that's been highlighted, and I'll read it again. It says:

> "During stakeholdering, some participants noted that total bill increases of the magnitude driven by the elimination of the seasonal class combined with the move to all-fixed residential rates raises customer affordability issues, which could possibly lead to customers choosing to disconnect from the grid. This would result in the stranding of assets and negatively impact all remaining customers."

I put to panel 3 whether they agreed that this was a concern, and they eventually did give me a form of answer, but also referred it to -- I think they referred it to you or to people involved in the preparation, because you or people that you worked with on this would have been the ones interacting with the stakeholders.

Does Hydro One agree that that's a concern, that once there's elimination of the seasonal rate class the impact on the R2 customers, if I think I can -- specifically the R2 customers in the seasonal class that the concern is raised with respect to, that that's -- there's affordability issues and possibly disconnection from the grid and stranding of assets and so on?

MR. ANDRE: Yes, so the -- you can see the paragraph starts with "during the stakeholdering", so this actually refers to comments that were made by the OFA, Ontario

Federation of Agriculture, and the comments that led to this is actually in the feedback summary document which is part of this report, and you're correct, Mr. Buonaguro, they were referring to R2. And I think what they were pointing to was this proposal of eliminating the seasonal class has very significant impacts on the amount that customers that would -- seasonal customers that would move to the R2 class, it has very significant impacts on the amounts that they would pay on their bill and the bill increases that they would see, and certainly that is something that's highlighted in the -- in the report, you know, and it's highlighted that 54 percent of seasonal customers roughly are R2, so you would have very large impacts on 54 percent, negative impacts on 54 percent of seasonal customers, and the 46 percent of seasonal customers that would move to R1, they would see a slight benefit. So this was referring to what would happen to R2 customers and the large impact that they would see.

Now, with respect to whether that large impact would drive them to disconnect from the grid, I think that's very much an individual decision. It depends on, you know, the extent to which they use their cottage, the extent to which individual customers can live with a sustained outage through their electricity, the extent to which they have solar panels and batteries and other steps that maybe make them self-sufficient.

So I think the, you know, the extent to whether they would disconnect from the grid, there's lot of factors that go into it, but the affordability issue is definitely relating to the increase that would -- that the seasonal customers moving to the R2 class would see.

MR. BUONAGURO: Thank you. So I think at least with at least to affordability issues you are agreeing that there is an issue with respect to these R2 customers you have just been talking about? I don't want to mischaracterize --

MR. ANDRE: Yes, that was a key element of what we highlighted in this report. And you know what? Just so -- because I think it's one page -- is this from your compendium? Okay. So you wouldn't have it. I was going to take you to the actual seasonal report that had a table below that, that had a table in the report that showed for a low-volume seasonal customer moving to the R2 class -- and by "low-volume" I mean a customer consuming 50 kilowatt hours per month on average, which may sound low, but which actually there is about 15,000 seasonal customers that are down at that level on average across the year, that they would see a combined impact of 177 percent on their monthly bill as a result of eliminating the seasonal class and moving to all fixed charges.

The component of just eliminating the seasonal classes, that on its own adds 126 percent to their bill. So, yes, I would agree that that could potentially pose an affordability issue.

MR. BUONAGURO: So this report was prepared in Q4 2016? I think that's when this -- I don't -- sorry, you are right, the compendium that I prepared for panel 3 only had the one page. I did distribute the entire document when I highlighted it --

MR. ANDRE: Yes, so there was an original report in August of 2015, and then there was an updated report that was submitted to the Ontario Energy Board in December of 2016.

MR. BUONAGURO: Right. And so if we go back to the proposal by Hydro One to the provincial government that included proposal for what turned out to be -- turned into the distribution rate protection plan, this was known by at least part of Hydro One, this affordability issue, you knew -- or Hydro One knew that eventually by Board order the R2 class was -- R2 seasonal customers were going to end up in the R2 class and experience major rate increases and possibly affordability issues?

MR. ANDRE: I don't know if it would have been known to the individuals putting together the proposal that went to the government, but, yes, it would have been -- I knew about it, for example.

MR. BUONAGURO: Thank you. And had the DRP been extended to include -- or, sorry, not exclude seasonal customers, they would have been afforded the same protection -- I don't know how to put it, but rates would have been -- the affordability issues that are raised here probably would be avoided; is that fair? If DRP funding was extended to seasonal customers?

MR. ANDRE: If the funding was extended to seasonal customers. As I said, I wasn't involved in the document that made the proposals, but I was involved in the working group that the Ministry staff put together to implement the Fair Hydro Plan and work out the details of the Fair Hydro Plan, and in that working group, certainly the direction when I attended the group came from the government as far as wanting to extend the rate protection to just year-round residential customers who had an affordability issue with respect to, you know, making a choice between paying the bill -- you know, paying the food bills or paying the monthly rent versus paying electricity, and those were the affordability issues that were highlighted as part of this working group.

MR. BUONAGURO: Thank you for that.

Perhaps I can take you to in this same compendium the beginning of the first document, which is Exhibit I, tab 5, Schedule BLC.4. Yes. So the actual -- you are at the attachment, that's it, thank you, and if I look at the answer to part (d), starting at line 21, it says here:

> "Hydro One informed Ministry staff of the OEB's decisions with respect to the elimination of the seasonal class and potential for seasonal customers being included in Hydro One's R1 and R2 year-round resident rate classes."

It sounds from that that Hydro One -- and I am assuming this may involve you because you were involved in working with Ministry staff -- Hydro One made sure that seasonal class -- seasonal customers weren't included in the DRP as a result of the elimination of the seasonal class.

MR. ANDRE: No, I -- Mr. Buonaguro, that characterization that we made sure that it wouldn't be -- what we made sure was that Ministry staff was aware that R1 and R2 -- sorry, seasonal customers could potentially or would be moving to the R1 and R2 classes, and made them aware with respect to, if you're writing the regulations you need to be aware of this fact. So if you want to accurately reflect your intent of what this DRP is -- or who is to benefit from the DRP protection, we just wanted them to be aware that the seasonal customers would be part of the R1 and R2 residential classes going forward, subject to the Board's review of the seasonal report that we've put forward, and subject to their final decisions with respect to that report.

MR. BUONAGURO: Thank you. Those are my questions, and I point out that I am bang on time.

MR. QUESNELLE: Perfect, thank you, Mr. Buonaguro.

Ms. Girvan? Oh, Mr. McGillivray, sorry, skipping over.

CROSS-EXAMINATION BY MR. MCGILLIVRAY:

MR. McGILLIVRAY: Thank you, Mr. Chair. My name is Jonathan McGillivray. I am co-counsel with Lisa DeMarco in this proceeding, and we are here today on behalf of Energy Storage Canada. Energy Storage Canada has a compendium, and I wonder if we could have that marked as an exhibit.

MR. SIDLOFSKY: That will be K11.3.

EXHIBIT NO. K11.3: ENERGY STORAGE CANADA CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 7.

MR. McGILLIVRAY: Thank you.

Witnesses, I would like to ask you today about the system benefits of general storage as they relate to rate design and load forecasting, and to do that I would like to address three areas: Connection impact assessment charges, rate classes, and the Anwaatin settlement proposal.

I'd like to start with page 4 of my compendium if we could go there. This is an attachment to undertaking response JT3.15 summarizing the EPRI Hydro One energy storage project, and I'd like to discuss with you some of the key elements of that project as they relate specifically to rate design and load forecasting. And I see on this page some of the key elements of the project.

Would you agree with me that they include developing a distribution needs assessment to identify, define, and quantify the value of services that energy storage can provide?

MR. BOLDT: Yes, I see that.

MR. McGILLIVRAY: Identifying energy storage system requirements to adequately address distribution needs?

MR. BOLDT: I am sorry, where is that?

MR. McGILLIVRAY: It's the second bullet under key elements, and developing energy storage deployment scenarios for insulation in relation to distribution feeders.

MR. BOLDT: Yes, I see that.

MR. McGILLIVRAY: Would you agree that these is part of the scope of this EPRI-Hydro One project?

MR. VEGH: The panel can speak for themselves, but I am not sure they are fully aware -- this is not one of their exhibits. They're addressing cost allocation and rate design, so I am not sure if they can shed a lot of light on this EPRI project.

But I will have the panel speak for itself.

MR. BOLDT: Yes, I am not familiar with this as far as the evidence that I am giving, speaking of the evidence.

MR. McGILLIVRAY: Thank you. I am hoping to address the system benefits of energy storage as they relate to rate design and load forecasting ultimately. This document is helpful because on the second page, it addresses some of the system benefits of energy storage which are also discussed elsewhere in the evidence in particular.

So we could move down to that second page, if that would be helpful. If we just scroll up a little bit from that figure, there's a list of -- this list is titled benefits, if you go up a little bit further on the bottom of the previous page.

So we can run through these, if that is okay?

MR. BOLDT: Sure.

MR. McGILLIVRAY: Looking at that page, some of the benefits of energy storage are that it has potential benefits to increase reliability and reduce the cost of electricity. You'd agree that's a potential benefit of energy storage?

MR. BOLDT: Yes. It says potential benefit, yes.

MR. McGILLIVRAY: Continuing on that page, applications of energy storage include frequency regulation, energy, security and outage management, power quality, voltage VAR management and peak shaving. Would you agree that's a potential benefit?

MR. BOLDT: Yes.

MR. McGILLIVRAY: And energy storage may be especially important as a flexibility asset to address the integration of variable generation, such as wind and solar. Yes?

MR. BOLDT: Yes.

MR. McGILLIVRAY: And has the potential as solution for remote communities.

MR. BOLDT: Yes.

MR. McGILLIVRAY: And energy storage may be a tool to improve asset utilization at the distribution level, and potentially for diurnal energy arbitrage.

MR. BOLDT: Yes.

MR. McGILLIVRAY: I see at the bottom of page 4, if we go back up a little bit, that Hydro One estimated in March that the project would be completed and ready for use in September 2018. I know you are not responsible for this project, but do you have any idea of the status of the report?

MR. BOLDT: No, I don't.

MR. McGILLIVRAY: Would you undertake to find out what the status of the project is?

MR. VEGH: Sorry, I think that really is for a different panel. My friend has had the opportunity to go through these issues with the assets panel, and the panels previous.

Again, he is reading a number of statements to this panel on cost allocation rate design external revenues, and they are agreeing that the statements are what they are. But this is really not their area, and I don't think it's appropriate to try to provide undertakings from this panel on issues that are really not relevant to their evidence.

MR. QUESNELLE: Mr. McGillivray, what's the purpose of your --

MR. McGILLIVRAY: I am happy to move on to topics that are directly relevant to rate design and load forecasting, if that's okay.

MR. QUESNELLE: Fine, thank you.

MR. McGILLIVRAY: If we could go to page 8 of my compendium, this is interrogatory response to ESC.2. And my understanding from this response is that connection impact assessment charges for generators, including energy storage customers, are derived by the time and TWE required to perform the studies and there are, I think, four rate codes discussed in this interrogatory response in relation to energy storage connection impact charges.

I think this question is for Mr. Boldt. Could you tell me what TWE refers to in that response, because I wasn't sure if it was transportation and work equipment or total work effort.

MR. BOLDT: Correct, it is transport work equipment.

MR. McGILLIVRAY: Okay, thank you. And my further understanding from this response is that Hydro One's view is that an energy storage facility acts as a load while charging from the grid, and as an generator while injecting energy back into the grid, and that the effort and time required to complete a CIA study for an energy storage facility is the same as any other generation facility. Do I have that right?

MR. BOLDT: Yes, that's correct.

MR. McGILLIVRAY: And this is part of the specific service charges which Hydro One is seeking to have approved in this proceeding, is that right?

MR. BOLDT: Yes.

MR. McGILLIVRAY: Would you agree with me that the revenue requirement does not account for the benefits savings and avoided costs of energy storage based on these charges?

MR. BOLDT: I'd just like -- I spoke to the manager of protection and control around your concern of the benefit of the energy storage device, and he indicated that energy storage may have a system benefit at a grid level, but it may actually be detrimental to the local feeder level.

And the reason that the study is done -- or the CIA as what we refer to it as -- is to evaluate the impact to the system, also to the neighbouring customers, and the quality of the power when this happens.

We, through the CIAs, are looking to recover the costs from the energy storage application, basically as per the distribution system code which, in section 6.2.11 -- I don't know if you that to bring up. Could you bring that up, 6.2.11?

Where it says -- at the beginning, it says:

"A distributor shall require a person who applies for the connection of a generation facility to the distributor's distribution system to, upon making the application, pay their impact assessment costs."

And as I've stated, or what you stated or read back to me is that during the time that the storage device is charging it's a load, and then when it's injecting, it's being treated as a generator.

So the CIA is being -- we are recovering the cost to do the study to make sure that the system at the distribution level is held whole and not being changed.

MR. McGILLIVRAY: So section 6.2.11 here refers to the connection of a generation facility, but that could be any kind of generation facility, not just an energy storage facility. Is that correct?

MR. BOLDT: Yes, that's correct. And the other thing I spoke to the manager of protection and control about was the benefits to the storage, there is also benefits to distributed generation, and that being if you have a solar farm or something, a wind turbine, or something close to the load where the consumer is using it, then there's a benefit because we don't have to build new generators, increase the size of our wires.

So there's an advantage to them as well, and that's why our manager of protection and control is saying we treat the storage device exactly the same as the generator.

MR. McGILLIVRAY: So to skip ahead a little bit to the sub-transition rate class, in that context, there's a discrepancy when it comes to renewable generation versus energy storage in relation to the application of gross load billing, is that right, in that renewable generation customers in the sub-transmission rate class have ceiling room up to 2 megawatts before they are subjected to gross load billing. You would agree with me on that?

MR. BOLDT: I am not familiar. Henry?

MR. ANDRE: Yes, the gross load billing applies to customers with renewable generation greater than 2 megawatts.

MR. McGILLIVRAY: Whereas energy storage customers in the sub-transmission rate class can only go up to potentially one megawatt before they are subjected to that gross load billing, is that right?

MR. LI: Yes, that's correct.

MR. McGILLIVRAY: So energy storage customers are at a disadvantage relative to renewable generation customers in that rate class?

MR. LI: Well, the reason there's a difference is basically energy storage is not classified as renewable generation, so there's a difference between 1 megawatt, where 2 megawatt is applicable only if the generation is renewable.

MR. McGILLIVRAY: So renewable generation and energy storage are not treated identically?

MR. LI: That's correct.

MR. McGILLIVRAY: Okay, and Mr. Boldt, you referred to that as well when you discuss the benefits and detriments that the manager of protection -- was it manager of protection and control had discussed this?

MR. BOLDT: Yes.

MR. McGILLIVRAY: Did you undertake any quantification of those benefits and detriments in order to understand how energy storage might work into the charges?

MR. BOLDT: Sorry, I don't understand your question.

MR. McGILLIVRAY: Well, if you're recognizing that there's benefits and detriments to energy storage, are those quantified so that you can use that information?

MR. BOLDT: Just give me a second, please.

MR. McGILLIVRAY: Thank you.

[Witness panel confers]

MR. BOLDT: So I am not aware of any studies that have been done to quantify it. But I will also like to go back to the Distribution System Code. And you stated earlier the statement of an energy storage unit is to form a generating facility when it's discharging but it's a load when it's charging.

If you look at -- if you can bring up 6.2.14, please. I just want to point to this, because what the study's entailed to or what it's doing underneath the distribution system code is it says:

"The distributor's impact assessment shall set out the impact of the proposed embedded generation facility on the distributor's distribution system and any customers of the distribution -- of the distributor, including, (a), any voltage impacts, impacts on current loading settings, and impacts on pole currents; (b), the connection feasibility; (c), the need for any line or equipment upgrades; (d), the need for transmission system protection modifications and any metering requirements."

It also states in 6.2.25, please -- there you go. Right there:

"A distributor shall ensure that the safety, reliability, and efficiency of the distribution system is not materially adversely affected by the connection of a generation facility in the distribution system."

In the development of our costs or the fees we are following the Distribution System Code in treating everyone that comes in the same equally. We have to do the studies to make sure for the reasons noted above that the system is not impacted, and there's no explicit -- or nothing explicit in the code that describes how the CIA shall be determined or the cost of the CIA, but we did use the time study of our actual estimates of time and to perform the study to come up with the costs, which have been reduced in this application.

MR. McGILLIVRAY: Okay, thank you. And just so I am clear, there's no section of the distribution code that applies to an asset that's both generation and load? These are generation?

MR. BOLDT: That's correct. And it has not been -- my understanding is energy storage is relatively new and the code hasn't been updated to reflect and specifically discuss energy storage versus generation, but it still has an adverse effect on the system or the potential on this distribution system.

MR. McGILLIVRAY: Technology is not so new, so perhaps an update is required. Would you agree with that?

MR. BOLDT: I guess I could agree to that. That would be up to the writer of the code.

MR. QUESNELLE: Note taken.

MR. ANDRE: If I could just take a minute to confer with the witness on this.

[Witness panel confers]

MR. ANDRE: And through my other work with our compliance group, I wonder, is this the full Distribution System Code that's on the screen? And I don't know what section refers to the definitions, but I just wanted to confirm since it just came up, I wanted to -- if we could go to the section that talks about definitions, and I just wanted to confirm the definition of a generator for the purposes of the Distribution System Code, because I think it might be helpful, if my memory serves me. That was definitions. Can we scroll down to generator? And I may be all wet, but I just didn't want to miss this opportunity if in fact it's covered. Oh, keep going. Generation...

All right. I had discussion with -- because you're right, energy storage is very new, and so we have been having discussion with our compliance group and our customer-service group about the treatment of generators, and I seem to recall our compliance folks saying that generation facility actually -- that the definition had been refreshed, but I don't see it here on the screen. So I can't confirm exactly where that is. But my apologies. I thought that the definition had been refreshed for the purpose of the Distribution System Code to include -- to specifically refer to energy storage, but I'd have -- if it may be helpful I can confirm if that's the case. I don't know if we are going to be back --

MR. QUESNELLE: But while we are there, is there one under storage or energy storage, or -- if we just confirm while we have got it up.

MR. ANDRE: Same place. Could you look for -- yeah, could you look for energy storage in the definition?

MR. McGILLIVRAY: Energy storage does not appear? Thank you.

MR. ANDRE: Sorry for taking you down the garden path there.

MR. QUESNELLE: All right.

MR. McGILLIVRAY: Just to be clear, I was suggesting that energy storage is not a new technology, and I understand that the Board has had a specific licence class for energy storage for approximately three years. Would you take that subject to check?

MR. ANDRE: Subject to check, yes.

MR. McGILLIVRAY: Thank you.

I'd now like to take you to page 37 of my compendium, which is an excerpt from the technical conference transcript in this proceeding. And there in lines 4 through 19 or so, Mr. Andre, you are speaking about how the rate class is applicable to energy storage, whether energy storage is treated as generation or load, do not account for the system benefits of energy storage, the savings, or the avoided costs; do I have that right?

MR. ANDRE: Yes, you have that right in terms of, you know, the costs are the -- is there any adjustment to the costs that are allocated for the benefits provided, and I would note that when you went through that list of five or six benefits from the EPRI study, you know, there were benefits with respect to reliability and voltage support, et cetera.

I would note that none of those five bullets referred to benefits associated with reducing the costs of the distribution system, and I think that's part of the reason why to this point at least when we look at allocating the costs associated with providing distribution service, yes, we don't reflect that in the setting of rates.

MR. McGILLIVRAY: Thank you, and that conversation continued as well, I think it's page 39 of the compendium, you indicated there that at lines 3 and 4 that there's a lack of clarity on how energy storage customers should be treated, and I think that's a direct quote?

MR. ANDRE: Yes, and I reaffirm that, I can reaffirm that, yes, we are in discussions with energy storage customers to confirm exactly the treatment, and we expect to reach out to the Board at some point when we have some clarity on what we propose to do.

MR. McGILLIVRAY: You are in discussions presently?

MR. ANDRE: We have some energy storage customers that we are in discussions with, yes.

MR. McGILLIVRAY: So none of these -- I think it's clear that none of these rate classes are specific to energy storage, and so there's no specific energy storage rate class that Hydro One uses for energy storage facilities, that's right?

MR. ANDRE: Yes, that's correct.

MR. McGILLIVRAY: And based on what you've just said, have you considered the possibility that a separate rate class for energy storage could be appropriate?

MR. ANDRE: That would be something that -- you know, certainly Hydro One is not unique in having to potentially connect energy storage customers. So I think that's something that may need to be addressed from an industry-wide perspective.

But from a Hydro One, our own utility's perspective, we have the rates that that are currently approved by the Board. We have the rates that we are asking the Board to approve in this application and no, at this point, no consideration has been given to how you would allocate costs to a separate energy storage class.

MR. McGILLIVRAY: Would you consider it?

MR. ANDRE: As I said, I think it's -- I think it's an industry-wide issue that would best be addressed with guidance and direction by the Ontario Energy Board.

MR. McGILLIVRAY: Thank you. If we can now go to page 45 of my compendium, and this is my last area. This is Anwaatin's settlement proposal, which I think has been discussed previously.

In light of this settlement proposal, would you agree me that Hydro One views energy storage as a viable distribution asset?

MR. ANDRE: I don't know if Mr. Boldt is familiar with this settlement proposal. I am not.

MR. VEGH: Again, this panel's really dealing with cost allocation and rate design, and not assets. So I would imagine -- I wasn't here, but I imagine my friend's client had the opportunity to ask questions about this with the appropriate panel.

MR. QUESNELLE: Mr. McGillivray, I see the question as being one if it's -- from in the context of what this panel's here to consider, is that the load forecasting and the cost allocation is that -- is there a context to your question that includes this panel, or is based on the subject matter of this panel?

MR. McGILLIVRAY: Well, I was hoping -- thank you, Mr. Chair -- that if Hydro One did, or on the basis of this settlement proposal does view energy storage as a distribution asset and that it may be looking to do further deployment of energy storage, that ultimately that would bear on load forecasting and rate design. And I was wanting to understand the assumptions that the people on this panel may make when it comes to considering the implications of energy storage for load forecasting, system productivity and rate design. That's the direction I was headed.

MR. QUESNELLE: Thank you, I think you have asked specifically in relation to the Anwaatin settlement, but that's very much the same question as you asked in general, I think, earlier.

Mr. Andre, do you have anything else to add?

MR. ANDRE: My colleague, Mr. Alagheband, indicates that yes, from a load forecast perspective, the extent to which the energy storage provides generation impacts, that would be taken account in the load forecast.

MR. ALAGHEBAND: What we have as a rate class for generator is the amount of load that generator would take as a customer, and then this amount is normally really low compared to what they generate.

So suppose if there is -- I don't know, if there's a facility that they generate during the day and at night time, they may have some lights they want to turn on and at that time, perhaps they are not generating. So when they take the load in, we calculate that. You know, we have a meter on that one, so our meters are two-sided. One is when the load goes in and another one for when the load comes out.

We don't include when the load comes out because it's a generator, but when it goes in, it is as a customer. And on that basis for distributor generation, we have a rate class and for that one we have a load forecast. Yes, we are including that one.

So if your facility includes taking loads from Hydro One distribution it's already included in our forecast.

MR. McGILLIVRAY: Are there any assumptions in that analysis that are particular to the fact that it's energy storage rather than another kind of distributed generation?

MR. ALAGHEBAND: At this point in time, we have one class called distributor generation and it includes every generator. So it includes, for example, wind turbines, it includes whatever facility is there which takes -- which is a generator.

If somehow at some future point or at some future point in time injects to the system, once they do that we say, okay, this is a generator and then at some point -- other points in time, they may take load from Hydro One distribution. That is what we call a generator as a customer.

So we are looking at the generator as a customer in our load forecast, not as a generator. Generator is a different story. This comes into total processes that we have from embedded generators inside the Hydro One territory.

MR. McGILLIVRAY: So fair to say that you don't
consider energy storage and its impact on peak load, for
example?

MR. ALAGHEBAND: Yes that's correct, that is a system
planning issue; it's not load forecast issue.

MR. McGILLIVRAY: Thank you, witnesses, Panel. Those
are my questions.

MR. QUESNELLE: Thank you, Mr. McGillivray. Ms.
Girvan?

CROSS-EXAMINATION BY MS. GIRVAN:

MS. GIRVAN: Thank you. Good afternoon, panel. My
questions are certainly a lot shorter given the opening
statements made today about the specific service charges.

So just briefly, there's a few things I want to
clarify. Could you please turn to Exhibit CCC, number 68?
So it's 53.CCC.68, and this is -- if you could scroll down,
please?

This is setting out the bill impacts for the acquired
utilities, and I just wanted to confirm that these are the
most updated rate and bill impacts.

MR. ANDRE: Ms. Girvan, they will be very close to the
final rates. It doesn't include the adjustment to revenue
requirement that was part of the Q11 exhibit, so this is in
reference to the -- it includes the changes that were made
in Q1.1 with respect to the allocation of costs to the
acquireds, so it reflects that.

But there was also a revenue requirement change, which
I think by 2021 was fairly small. I know the change in '18

was more significant, but in 2021 the change in revenue requirement was very small, so it wouldn't reflect that small change.

But other than that, it would be the most current, and then obviously it wouldn't reflect any of the discussions we have had since this interrogatory was filed.

MS. GIRVAN: What do you mean, discussions?

MR. ANDRE: Well, I mean the changes to external revenues, the updates that have been provided by the various panels.

MS. GIRVAN: So we won't see the final impacts of this until you do your final rate order?

MR. ANDRE: Rate order. You said the final impacts of this.

MS. GIRVAN: Of everything, yes

MR. ANDRE: Yes, that's correct. The impacts of the changes to external revenues and any other revenue requirement adjustments, which was also made -- I think on panel 1, we made some adjustments there.

So all of those there be reflected in the draft rate order, as well as whatever decisions the Board makes with respect to revenue requirement.

MS. GIRVAN: Okay. But you don't imagine these are going to change significantly?

MR. ANDRE: I wouldn't --

MS. GIRVAN: I'm just trying to get an update, you know, the most updated that we have on the record to date.

MR. ANDRE: I think there this is -- there may be small changes, especially if you are looking at the total bill impact, I think there would be fairly minor changes, I would think.

But without running through, there have been a number of updates to revenue requirement and we heard the impacts today or the updates today around external revenue, so there may be some changes, but I can't really --

MR. QUESNELLE: Mr. Vegh, I am wondering rather than going through all the exhibits and try to do an update based on a new revenue requirement, if there was a percentage difference based on the updates to the overall revenue requirement, perhaps that would give a comfort level as to what the outflow of that would be.

Like if we are talking less than a percent, people can look at this and say okay, in that context I don't need an update of this particular chart.

MR. ANDRE: You are absolutely right, Mr. Quesnelle. I mean, if we had a sense of what happens to the revenue requirement, that percentage change effectively flows down to the rates. So I would agree that if we had that number we could comment on what it would mean for rates.

MR. QUESNELLE: And if that could be worked on quickly just to get a sense of it, and then -- and I don't know if you can do a back-of-an-envelope over the lunch sort of thing as to what -- you know, kind of a -- add some context to this, and perhaps that would be helpful.

MS. GIRVAN: Yeah, that would be helpful.

MR. ANDRE: We can do something, I am sure.

MR. QUESNELLE: Okay, thanks.

MS. GIRVAN: Okay, thank you.

Mr. Andre, I just wanted to ask you this, and I have asked you this before, but is Hydro One doing anything regarding the elimination of the seasonal class at this time? Or are you waiting for OEB direction?

MR. ANDRE: Yes, the report's in front of the Board. The Board's initiated a proceeding to look at the details of that report, and we are waiting for the direction.

MS. GIRVAN: Okay, all right, thank you.

Now, with respect to the amounts that you discussed this morning, panel, the 341,000, the 1.3 million, and the 2.1 million, how are those amounts going to be reallocated? To what rate classes?

MR. ANDRE: I can speak to that. So the reduction in external revenues applies across -- the way the cost allocation works, it would apply across all classes. So any reductions gets spread across the classes in proportion to the revenue that's generated by each class.

MS. GIRVAN: Okay. And is that in part because these charges aren't class-specific; right?

MR. ANDRE: That's just the principle that the Board has adopted. I mean, there is an opportunity, for example, for sentinel light revenue to be specifically allocated or associated with the sentinel light class, but all of the other external revenues are treated as a common bucket and shared among all rate classes because they are not specifically associated, as you say, Ms. Girvan.

MS. GIRVAN: And that's why you are saying the impact isn't significant.

MR. ANDRE: That's correct, yeah.

MS. GIRVAN: Okay, thank you.

Could you turn to the list of the specific service charges, please, and that's found in H1, tab 2, schedule 3. And I just had a few questions. If you look at the codes 22 and 23. And I think you are proposing to increase those services -- the charges to $320 and $850; is that correct?

MR. BOLDT: Yes, that's correct for 2018, yes.

MS. GIRVAN: Okay, can you give me an example of when this would be the case, when would these charges be enacted or be charged to the customers? Under what circumstances?

MR. BOLDT: So this is, sorry, 22 and 23. 22 is a disconnection and/or reconnection. Actually, I will wait for the screen to catch up, maybe.

MS. GIRVAN: Yeah, thanks.

MR. BOLDT: It's page 5. There we go.

So as you can see in 22, which is a disconnection and reconnection at the pole during regular hours, the charge is currently $185. And it's billed once for the disconnection, and then when the customer pays it's billed again for the reconnection. And the one below that, it's the -- it's at a pole. The key is that it's at a pole and it's after regular hours, so currently it's $415.

The time study looked at both of these, and in this particular case we are sending a large truck with two workers to do this disconnection, and it's something that, there's physical labour to actually disconnect wires when this happens, and -- as opposed to the meter that is much easier to do the work.

MS. GIRVAN: So under what circumstances? Would it be someone's renovating their house or is that the type of circumstance that this would be charged?

MR. BOLDT: No, like, if this was for maintenance, if you were changing your panel in your home or upgrading your panel or doing something. Every customer gets a free disconnect and reconnect once per year. This would be -- basically in these categories here it's for collection, so non-payment of account.

MS. GIRVAN: Sorry, non-payment of account?

MR. BOLDT: See, it's -- and the category is collections.

MS. GIRVAN: Yeah.

MR. BOLDT: So it's in arrears of paying your bill.

MS. GIRVAN: Oh, I see. So you're -- but I thought you said it was if you are changing out your panel.

MR. BOLDT: No, no, if you're changing your panel, so you would call in and ask for a disconnection and a reconnection, and that is free once per year during regular hours.

MS. GIRVAN: Okay.

MR. BOLDT: This is if there is a collection of a service for non-payment, and through the process where we actually get to do the disconnection to the point where there is a disconnection notice issued, this is rolling a truck for non-payment to disconnect the service.

MS. GIRVAN: Okay. And what's the difference -- under what circumstances would you disconnect at the pole versus disconnect at the meter?

MR. BOLDT: There's some things. Lots of times it might be a farm situation. An example would be where they have a CM service or what they call a central metering service, and what that does is the power comes in from the road to a transformer, and the metering is not -- like, the current doesn't run through the meter. The meter has what's called a current transformer, and it -- and potential on it, which causes it to turn. So the only way to do this disconnect would be to disconnect it at the road.

There's other disconnections that may happen where the meter may be inaccessible, may be locked, it could be in a building where they are not giving us access, and in those cases you would be forced to do it at the source somewhere else.

MS. GIRVAN: Okay, thank you.

And down under 25 and 26, again, can you give me some examples of this category of service call?

MR. BOLDT: Yes, so a service call, lots of times what -- this is referred to as a service call, where there's customer-owned equipment, and it's regular hours and also overtime hours.

Typically where this effect would come in and -- is that when they call in and they are out of power, let's say, and what would happen is the trouble crew, or when they call the OGCC, or control centre, the customer is asked to make sure that it's not their equipment that is causing the outage. And the -- like, something that can happen is that there is power at the meter outside their home, and maybe they have got a defective breaker in their house and -- which causes their power to go out at their main panel, and instead of checking with a neighbour -- and we help to assist them on this when they call us -- check with a neighbour, do you have someone, is there power.

The other thing is our new meters today that are electronic meters, if the power's out at the meter the face will not be lit. Like, if the system is out as opposed to that, and what would happen here is that we roll a truck, whether it's regular time or after regular hours, and we arrive there to determine that it's the customer's equipment that has caused the outage, their own outage. And we are just looking to recover the costs rather than putting it against a trouble call when it's really their equipment that has caused their own problem.

MS. GIRVAN: Okay, all right. Thank you, those are my questions.

MR. QUESNELLE: Thank you, Ms. Girvan.

Mr. Brett?

CROSS-EXAMINATION BY MR. BRETT:

MR. BRETT: Thank you, Mr. Chair. My name is Tom Brett. I represent BOMA. I'd like to start by asking you if you could turn up Exhibit G1, tab 2, schedule 1. I just have a few questions on cost allocation and one question on rate impacts. So that's page 5 of 8, G1, tab 2, schedule 1, page 5. Yes, that's it.

I wanted to ask you, on this table, I notice that the -- that the acquired utilities do not seem to have a distribution -- distributed generation rate class, so that you've essentially assigned them the -- Hydro One's distributed generation rates; is that right? I am looking down under Norfolk, Haldimand, Woodstock existing classes. And if you go through those classes, there doesn't seem to be a class for distributed generation; is that right?

MR. LI: Just give me a second here.

MR. BRETT: Sure.

[Witness panel confers]

MR. LI: Yes, if you look at Norfolk embedded distributor ...

MR. BRETT: Yes.

MR. LI: When they come to -- I am sorry, just give me a second here.

Sorry, yes, I got a little bit confused there, I am sorry. There is no DGen customer to move into the Hydro One class. They don't have any DGen customers.

What you are referring to, embedded distributor, that's a different class.

MR. BRETT: I am referring to generators.

MR. LI: No, no, there's no generators, sorry.

MR. BRETT: So if there is one in the future, what is the intent? That they will use your distributed generation rate?

MR. LI: If there is one in the future, yes, it will go into the DGen class, the Hydro One class, yes.

MR. BRETT: The second thing in this table I wanted to check with you is I notice, looking again at the Norfolk column and Woodstock, they don't appear to have a microFIT rate class, but you do.

So is that the same answer, that you don't have any microFIT facilities at the time being?

MR. LI: No, microFIT, I think we are just talking about the five -- was it $5 and -- can you let me double-check? Just give me a second.

MR. QUESNELLE: Mr. Brett, from this chart you are looking at, microFIT is listed at the bottom of the list of those service customers. There is a microFIT on the bottom of each line under Norfolk, Haldimand and Woodstock.

MR. LI: Yes, I'm sorry, it is the same thing. It's basically a fixed charge every month. I believe it's $5.40, but I could be wrong; that's why I wanted to double-check.

But it's exactly the same. All LDC, I believe, pay the same charge every month, so there's no difference there.

MR. BRETT: So nothing would change there?

MR. LI: There's no change at all.

MR. ANDRE: And to clarify further, it shows that -- what this chart is showing is that from 2018 to 2020, right, which is the first column, the charges that will apply are the rate classes, the existing rate classes that exist for Norfolk, Haldimand and Woodstock.

And then the second column says that for the period '21 to '22, you will see there's NAs for the individual acquired utilities because those classes cease to exist. And what the top part of the chart shows was that for '21 and '22, there will be separate classes -- well, it shows the -- it shows the new classes that are being created and it shows the rate classes where existing Norfolk and Haldimand and Woodstock customers are being merged with.

So they are being merged with the street light class, the sentinel light class, the USL class. As you point out, it doesn't show for DGen because there are no current DGen customers. But if there had been, it would show that they would be -- the acquired customers in that class would be moving to Hydro One's DGen class and then microFIT, they're moving to Hydro One's microFIT class.

MR. BRETT: Thank you. Could you turn up page 35 of SEC's compendium for this panel? I don't have the K number, what's the ... Mr. Shepherd's compendium?

MR. SIDLOFSKY: It was Exhibit K10.7 from Tuesday.

MR. BRETT: Okay. So at page 35 of that exhibit, that's the page that had the three tables on it with the very small numbers. I don't mean small in magnitude, but small in print size, at least for me.

Do you have that? Yes, you do, okay.

I wanted to ask you about the differential, if we look at the -- and this is really a follow-up to a question you received this morning. But if we look at the top table, the top chart, it talks about total GBV on the left-hand side that should be allocated to the acquired utilities. And on the right-hand side, it's GBV that's being allocated under the existing cost allocation system.

And GBV, I am assuming, gross book value is the same as -- that's to be considered a synonym for gross fixed assets?

MR. ANDRE: Yes.

MR. BRETT: The numbers -- you talked about this this morning, but the number under your existing -- the numbers of assets that would be allocated, these are the capital-driven assets, the various classes of fixed assets including stations, I guess.

In any event, the 531, as I understand it, is what your existing cost allocation system would allocate and then over on the left-hand side, the 271 million is what should be allocated and what you did allocate following the Board's directions; is that right? That's directly from --

MR. ANDRE: Yes, so the column on the right, or the right side of the table, you see it says total GBV that is being allocated and then in brackets non-adjustment, so before the adjustment.

MR. BRETT: Right.

MR. ANDRE: And then the column on the left-hand side is post the adjustment and that is the actual assets for those particular categories of US of A accounts that are being allocated and are reflected in the 42 million in total costs that get allocated to the total acquired classes.

MR. BRETT: Right. Now the -- perhaps just while we are on this, I will just reverse the order of my question for a moment. If you look down a little further below -- well, let me go back to the sequence I was going to use.

The differential between those two numbers, as you can see, is somewhere around 260 million. I hope I have got this right -- no 240 million, maybe. In any event, it's a large amount. So you have 532 comes down to 271. So you have a differential there of about 261 million, roughly; is that right, give or take?

MR. ANDRE: Yes, give or take, that's right.

MR. BRETT: Now, the question's sort of an open-ended one, but what -- that's a large differential in the sense that one number is about half the other. What accounts for that, broadly? What accounts for the size of that differential?

MR. ANDRE: I think -- so we are looking at the US of A accounts related to poles, transformers, wires, and so I think what you are seeing there is a reflection that Hydro One in total serves a widely dispersed customer base. And so the number of poles, the kilometres of line that it requires to serve its customers is on average greater than other utilities. You know, where other utilities have a certain number of customers per pole, Hydro One has a certain number of poles per customer. It's quite disparate, and so I think that's what you are seeing there.

So if you only looked at the peak loading and said based on the peak loading, let's give them a share of Hydro One's total service territory that includes serving all of this low density area, it would attract a bigger share. Then you say, no, no, if you look at just the Norfolk area and just the Haldimand area, the amount of assets required to serve those customers is much lower than the average number of assets required to serve Hydro One customers in general.

MR. BRETT: More homogeneity in terms of, more homogeneity in terms of the assets and lesser distances.

MR. ANDRE: Yes, more homogeneity and more density packed, yes.

MR. BRETT: And if you go down on the same page to a little -- on the third of these -- well, no, I guess let's go the second chart, the second block, it's the same -- I just want to check if it's the same numbers.

This is net book value, which I guess is essentially rate base. And you've got over at the right in terms of what your normal -- what your existing cost allocation would allocate is the 371 -- I think I am reading that right. I hope I am.

MR. ANDRE: 321, I think.

MR. BRETT: Okay. 321. And then on the left side -- under the left side of the chart it's down to about 178. Now, what -- I understand the -- why I think the disparity between the two. That would be a similar answer to what you just gave me for gross fixed assets; in other words, the difference between the 321 and the 195. Why are the -- I guess the question that came to my mind is why are the relative -- why is the ratio different for net fixed assets relative to gross fixed assets? What's sort of happening in the middle there to make that a different ratio?

MR. ANDRE: And I guess it would be the treatment of the accumulated depreciation. So we used the relationship between gross book value of assets and net book value of assets that exists in the cost allocation model, and we used that relationship to translate gross book value down to net book value. And --

MR. BRETT: Right.

MR. ANDRE: -- the difference is associated with the different amount of accumulated depreciation.

MR. BRETT: Right.

MR. ANDRE: Yeah, the details are -- so this is a summary.

MR. BRETT: Right.

MR. ANDRE: And if you go to the actual spreadsheet where these tables are pulled from you will see that derivation and you will see the impact of accumulated depreciation, but we use that ratio between gross book value and net book value, which -- the difference being accumulated depreciation, and we use that ratio to derive the numbers that you see in this chart.

MR. BRETT: Right, and -- now, just starting from that, the -- you touched a little bit on this earlier this morning, so I just wanted to make sure I have kind of got this correct directionally. If you continued to make acquisitions of other utilities, you would have a set of numbers -- well, let me go back. I am missing a step there. But just the difference between the -- your cost allocation, the amount that would be allocated on your existing cost allocation and the amount that you actually allocated, the difference between those two, as I understand it, is allocated to the other Hydro One customers, essentially.

MR. ANDRE: Yes, that's correct.

MR. BRETT: And so if you made other acquisitions would it be a fair assumption that -- directionally that you would have similar results, you'd have similar tables to this, coming out of -- you'd have a similar cost allocation adjustment that would be necessary, not the exact same numbers, of course, but that you are going to -- you would find that you would need to -- after you made your adjustments to make you compliant with the Board direction, you'd have to reallocate some of that, some of those accounts, those poles, the physical accounts, you'd have to reallocate some of those to the other ratepayers; is that fair? I mean...

MR. ANDRE: I think that's a fair statement with respect to the US of A accounts that are on this chart.

MR. BRETT: Right.

MR. ANDRE: But then there would be the common assets and the shared assets that I discussed with --

MR. BRETT: You would have reverse flows.

MR. ANDRE: Yeah, so for those items they would be shared among the acquired classes, so they would attract some of those costs, and I think when you look at the total dollars that are being allocated the, you know, numbers show that the acquired classes are in fact attracting a fair amount of common and shared assets so that that flow would offset -- some might argue that the flow is too much one way versus too much the other way, but there is absolutely an offsetting flow from the numbers that you see here versus the allocation of common assets and shared services.

MR. BRETT: But it would be fair to say -- I mean, we discussed earlier in the hearing a bit the sort of the overriding size of those physical assets and their impact that they that drive on the revenue requirement and on rates.

Would it be fair to say that the reverse flow, as I'm putting it -- or you're putting it or I am putting it -- that comes the other way by way of the acquired assets absorbing a share of common costs, it would not typically offset the first effect, would it, because it would be considerably smaller? I mean, we don't have the numbers in front of us, but I got the sense from listening to you that those -- and from reading the evidence that that flow would be smaller in magnitude.

MR. ANDRE: Well, I think what the evidence has shown in the undertaking in -- perhaps I could take you there, the undertaking that we visited quite a bit this morning.

So that would be JT3.18-19, and if we could bring that up just to refresh people's memories, but -- so JT3.18-19. And page 2.

So what this chart shows is that in terms of the costs that are added to Hydro One's revenue requirement as a result of integrating the utilities, that's $25.6 million in additional costs, in additional revenue requirement. But in terms of the status quo -- and actually, sorry, I mean, status quo is the number, but in terms of the allocated costs, which we have talked about this morning as well, which is 42 million, so there is -- that is the amount of costs that we are allocating to the acquired utilities versus the 25 million in incremental costs.

So we are definitely allocating to the acquired utilities some of those shared services, so based on a comparison between the 25.6 and the 42 million that actually gets allocated to the acquired utilities, I would say the flow tends to be -- the acquired utilities are absorbing some of those shared-services costs, more so than flowing the other way.

MR. BRETT: All right. It's -- that's your answer. I can't -- but in just going back to the question, the amounts of money that I was quoting, the differentials that I was quoting between the -- on the physical asset costs, I mean, are we comparing apples and apples here or is this -- this is a different way of looking at it?

MR. ANDRE: I would say this is a different way of looking at it. I mean, what you were looking at before shows that could more have been allocated to the acquired classes and provided more of a benefit to the existing legacy customers? I think those are the tables that you had started that shows that there's quite a bit of reduction in terms of what the model would allocate versus what we end up allocating after the adjustment factors.

MR. BRETT: Yeah, I was actually trying to get at the amount of extra asset cost that's loaded on to the existing customers.

MR. ANDRE: Right. And so I think for that purpose, Mr. Brett, it's exactly the table that you're seeing here. The amount of costs that are getting loaded on, as you say, or added to the revenue requirement that Hydro One needs to recover is 25.6 million. So to the extent that anything over and above 25.6 million gets allocated to the acquired utilities, it means they are sharing in some of those costs that would normally have flowed, and like right now, before the integration, are normally flowing to the other classes, so to the extent that it's over and above 25.6, that represents a reduction to the revenue requirement that's being collected from Hydro One's legacy classes.

MR. BRETT: Okay. One other question. If you could turn up -- this is just on a more -- a question on rates, really, rate design, rate impact. If you could turn up, please, Exhibit Q, and this is my last area, just a couple of questions in this area. Exhibit Q, tab 1, Schedule 1. That's your updated -- page 3 of 25, and that's your -- this is your updated evidence in December. And so that's

Q, Exhibit Q, tab 1, Schedule 1, page 3. And that's from your December 21st filing. And it's --

MR. ANDRE: I have it, but let's just wait for it to come up on the screen.

MR. BRETT: Yeah, I will just wait a moment. Yes, here we go. Could you just scroll down a little bit to the paragraph below -- that's it right there, thank you.

Now, I just want to go over this with you. The updated 2018 revenue requirement reflects an increase of 3.1 percent over 2017, OEB-approved levels after adjustment for reduced load forecast 3 percent, the resulting average impact on distribution rates is an increase of 6.1 percent in 2018, and an average of 3.4 percent per annum over the term.

And my first question is, are these -- I know we've had a number of updates and there was talk yesterday about a Board Staff IR, I think 84 or 94. But are these numbers pretty much the most current numbers? I mean, the most current numbers don't vary materially from these numbers; is that fair?

MR. ANDRE: And I think this was part of what Mr. Quesnelle was asking about --

MR. BRETT: Yes, it is.

MR. ANDRE: -- to get the most current numbers on the record. So I believe that the statement made at the beginning of panel 1, in terms of revenue requirement changes, would impact the numbers that you see here that we announced. And then the changes to external revenue that we talked about today would be the second impact that I am aware of.

I don't know if in between panel 1 and what I heard today on external revenue, I don't know if there were other items. I am sure our team will know, but those are the two that I am aware that would change what you see in this table.

MR. BRETT: My purposes for this, it's sort of -- if it's approximately in the ballpark, so I think I will just proceed. My question's a general one, so if we get another document that fine-tunes this, it wouldn't change the impact of my -- it wouldn't change my question at all.

My question really is would you agree with me that the rate impacts and the distribution rate and the increases to the distribution rate, those are the matters -- it's the distribution rate that reflects your costs as a distributor. In other words, that's the cost that you, in a sense, are accountable for? Or that's the rate increase, if you like, that you are accountable for or that you can control.

Would you agree with me on that? In other words, the other components, just to -- the other components of the bill, whether it be commodity, or transmission rates, or global adjustment, or IESO fees or what have you, you can't do anything about that; that's a given for you.

What you can control and work on and try and make more efficient is your distribution operation, which gets reflected in these percentages of distribution rates; fair enough?

MR. ANDRE: Mr. Brett, I think that's a fair statement, that it's the distribution component of rates that we have control over, with one refinement.

If you look at this paragraph, what it indicates is that distribution rates are also being impacted by the resetting or rebasing of load from what was approved in the rates that we currently have versus the updated load forecast that reflects significant reduction in the actual load that we have seen in our system.

So when we talk about distribution rate increase -- and like I said, I agree with your statement -- to the extent that the distribution rate increase includes a component that's driven by the reduction in load, I would put that in the similar category in terms of really being beyond Hydro One's ability to control.

MR. BRETT: That component is slowly disappearing; is it not? If I have the rate sort of -- at least for the residential classes, you're almost at a straight per customer basis?

MR. ANDRE: Yeah, I think going forward, the differences in load forecasts from one application to when you reset it at a subsequent application, you will see less of that impact on revenue requirement because the number of customers is a much easier figure to forecast.

MR. BRETT: Fair enough. My question really is -- my second question there is, I mean, it's a corollary to the first question. If something were to happen, you know, steps were to be taken by a government or whomever, the Board, to reduce other elements of the bill, you know, not the distribution rate, but the other elements of the bill so that your -- so that these numbers here, these three-and-a-half percent annual increases in rates were no longer 1 percent of the bill, but were 2 percent or 1 and a half percent, you would not feel in any way that that was a failure on your part? I mean, you would -- you are working to make your own piece of this as efficient as possible. So the fact that the number jumped from, you know, to 1 and a half percent of the bill from 1 percent of the bill, that's not on your -- that's not to your account, so to speak; fair enough?

MR. ANDRE: I think we still want to show the bill impacts so that the Board understands what it means to the customer's total bill. I think I have said before that, you know, what's happening to a customer’s total bill is really ultimately what they are concerned about.

But I do take your point that if distribution -- because other portions of the bill decrease and then the distribution component becomes a bigger share of the bill, and therefore any increase in that component represent as bigger increase in the total bill, that is, to a large extent, outside the control of Hydro One.

But I think you heard our panels that the focus is on trying to reduce the costs and get more productive and more efficient in that component of the bill that we have a hundred percent control over.

MR. BRETT: Thank you, those are my questions.

MR. QUESNELLE: Thank you, Mr. Brett. With that we will adjourn for lunch and we will return at 5 to 2:00. Thank you.

--- Luncheon recess taken at 12:57 p.m.

--- On resuming at 2:07 p.m.

MR. QUESNELLE: Please be seated.

Mr. Vegh, any preliminary matters this afternoon?

PRELIMINARY MATTERS:

MR. VEGH: Just one for the applicant to speak to the issue raised this morning by Mr. Rubenstein, with respect to the memorandum of agreement that was entered into last night between the Power Workers and Hydro One. So we have made inquiries, and I could tell the Board that the memorandum of agreement is for two years, 2018 to 2020. They are still months away from finalizing a collective bargaining agreement and will continue in negotiations, and I am advised that the people I spoke to at least are still reviewing the document.

And in terms of the contents, I can also advise that the wage increase escalator in the ratified memorandum of agreement is higher than what is assumed in the application, but Hydro One is not seeking any change to what is requested in the application to address that higher wage escalator, so it has no impact on what's being requested for rates in this case.

MR. QUESNELLE: Okay. So I understand the process -- so that I do understand the process, Mr. Vegh, so there's a memo of understanding, and that memo of understanding lays out the parameters, but there is no finalized collective agreement at this point and there won't be, so --

MR. VEGH: That's correct.

MR. QUESNELLE: -- so the memorandum has the, I suppose the -- I'd say the force, it's not a force, I suppose the collective -- the bargaining is still going on, but at this point there is a strong indication that the driver to the salary will result in an amount higher than what's embedded in the application as it stands now.

MR. VEGH: Yes, that's correct.

MR. QUESNELLE: All right. Thank you for that. Mr. Rubenstein?

MR. RUBENSTEIN: Well, I would still like to see the information that I originally sought. I know my friend was saying that the collective agreement -- as I understand a memorandum of agreement has been signed and now ratified by the PWU, and what is left, in my understanding, generally is translating that into existing -- amending the existing collective agreement, but it's more of a formality.

With respect to the specific areas, I think they are relevant. Even if my friend is not seeking an adjustment to the application I think it is still relevant for many of the issues that were raised on panel 2 about, you know, the trajectory of wage increases. It's important, as well, what my friend is talking about that the wage increase is higher than embedded, I still am unclear if there is -- was there changes to a pension contribution, ratios -- I know that's been an issue that's been, I believe, discussed with the panel and was discussed during cross-examination on panel 2, as well as discussed in previous Board decisions. There are the changes to overtime rules. I mean, usually these things are covering a lot more than just simply the wage increase.

MR. QUESNELLE: Mr. Vegh, you mentioned that there's still conversation going on. Have you received final direction from your client as to whether or not they would be supplying the memorandum?

MR. VEGH: No, so I wouldn't take this as an objection, sir. I would say that my -- as currently advised, they are still reviewing it, and they are not in a position right now to agree to provide it, because they are still reviewing it and still reviewing it, frankly, with the PWU, so we are not in a position to agree to provide that information today, but I wouldn't take this as a refusal, and of course we are in the Board's hands as to what should be the next step.

MR. QUESNELLE: I suppose from a timing perspective obviously the provision of it in advance of argument would be, you know, obviously preferred. And so -- and we haven't discussed the schedule on that, but maybe when we get to that conversation we can revisit this and get some assurance that we could have it, the caveat that -- the argument schedule around the provision of it, assuming that it will be provided, but I recognize you haven't got final direction on that as well.

MR. VEGH: Yes, it would be helpful when we talk about the "it" that's being provided -- as I say, it's not a refusal, but I think there is still some concern about putting it out in the public as opposed to, say, a summary of what's in the memorandum of agreement.

MR. QUESNELLE: Well, and I suppose if your client wants to apply for a confidential treatment at this point, Mr. Rubenstein, would that be preferred to a summary? Or both, I suppose.

MR. RUBENSTEIN: Well, sure. I mean, I am somewhat unclear of why at this point there should be any confidentiality, since it's been ratified, but putting that aside, I don't fully understand, and maybe I don't fully understand this at all, so that's fine.

That's fine, but just to be clear of what we are seeking, it's in addition to the memorandum of agreements, understanding the impacts on the distribution business. So this is a PWU contract that -- for the entire company, and we are interested in understanding that but also understanding what those impacts may look like for the revenue requirement in either direction. I know they are not seeking relief, but to understand just -- even with the increase being above, what actually does that look like in the revenue requirement, as well if there are other implications that just are not simple flow-throughs or pension adjust -- if there's a contribution change or a lump-sum payment, or those things that don't easily map, that we would understand that.

MR. QUESNELLE: Thank you, Mr. Rubenstein.

So Mr. Vegh, if you just want to take that under advisement when you are having conversation with your client, then you know what the request is for anyway and see what your client is willing to provide.

MR. VEGH: Thank you. And I think the -- I think that's fair. Why don't I take that away then.

MR. QUESNELLE: All right.

MR. VEGH: That's -- we do have some -- the witnesses were going to provide some information requested, but I think there are a couple of other preliminary matters that we can address first, and then we will hand it back.

MR. QUESNELLE: Great. Okay. Thank you.

Ms. DeMarco?

MS. DeMARCO: Mr. Chair, I do have a preliminary matter, and it pertains to the Anwaatin panel that's scheduled to appear on direct and cross-examination tomorrow, and if it pleases the Panel, we undertake to determine who wishes to cross-examine, and it appears as though, subject to a few qualifications of Board Staff, which may be achieved through undertaking, there is no one who wishes to cross-examine, so we may be in a position to stand down that panel if it's convenient for you.

MR. QUESNELLE: All right. Well, we are prepared to just receive the evidence as filed, and any undertakings that you are willing to take, I believe it's Board Staff that had some clarifications that we could -- that you would undertake to respond to?

MS. DeMARCO: It's my understanding that they may wish to file those as undertakings with the court reporter and we will undertake to respond to them promptly.

MR. QUESNELLE: Okay. Mr. Sidlofsky, do you want to do it that way? Do you want to read it into the record or --

MR. SIDLOFSKY: I could do it either way. I do have a paper copy here, but I'd be happy to read it into the record and simply have my friend Ms. DeMarco undertake to provide responses.

MR. QUESNELLE: Is that satisfactory?

MS. DeMARCO: Sure.

MR. QUESNELLE: Okay, let's do that.

MR. SIDLOFSKY: Okay. Board Staff had two questions for Anwaatin. First, on June 15th, 2018 a settlement proposal was filed between Anwaatin Inc. and Hydro One with respect to the "Motion to review and vary the Ontario Energy Board's decision on Hydro One Networks Inc.'s transmission rates in EB-2016-0160." This has been filed as Exhibit K4.4 in this proceeding. The question is: Please discuss what impact, if any, Anwaatin believes the filing of this settlement proposal would have on this proceeding.

The second question refers to Anwaatin's response to Board Staff Interrogatory No.8, and in that interrogatory Board Staff had asked Anwaatin to state what it is requesting that the OEB direct Hydro One to do in its decision on the application. In that response Anwaatin said that it hoped to be in a position to provide the Board with further information in short order. The question now is: Is Anwaatin now in a position to do this, given the filing of the settlement agreement on June 15th?

MR. QUESNELLE: Okay, thank you. And so undertaking number?

MR. SIDLOFSKY: And that will be Undertaking J11.4.

UNDERTAKING NO. J11.4: WITH REFERENCE TO EXHIBIT K4.4 IN THIS PROCEEDING, (1) PLEASE DISCUSS WHAT IMPACT, IF ANY, ANWAATIN BELIEVES THE FILING OF THIS SETTLEMENT PROPOSAL WOULD HAVE ON THIS PROCEEDING; (2) WITH REFERENCE TO ANWAATIN'S RESPONSE TO BOARD STAFF IR NO. 8, AND IN THAT INTERROGATORY BOARD STAFF HAD ASKED ANWAATIN TO STATE WHAT IT IS REQUESTING THAT THE OEB DIRECT HYDRO ONE TO DO IN ITS DECISION ON THE APPLICATION; IN THAT RESPONSE ANWAATIN SAID THAT IT HOPED TO BE IN A POSITION TO PROVIDE THE BOARD WITH FURTHER INFORMATION IN SHORT ORDER. THE QUESTION NOW IS: IS ANWAATIN NOW IN A POSITION TO DO THIS, GIVEN THE FILING OF THE SETTLEMENT AGREEMENT ON JUNE 15TH?

MR. QUESNELLE: Great, thank you Ms. DeMarco.

Okay, Mr. Vegh. Updates or new information?

MR. VEGH: Yes, thank you, so Mr. Andre would like to address a request from this morning's discussion.

MR. ANDRE: So Ms. Girvan had asked about whether the impacts -- bill impacts shown in Interrogatory I.53.CCC.68 are still accurate. And as, Mr. Quesnelle, you pointed out, understanding the impact on the revenue requirement --

the changes to revenue requirement that Hydro One has made over the course of this application would be helpful, and so I did that over lunch.

So the impacts that are shown in CCC 68 are relative to what was filed in June. I know the response references Exhibit Q, but that's with respect to the changes in the allocation to the acquired utilities that was factored in. But in terms of a revenue requirement, it's still referred to the June revenue requirement.

So with respect to June, we had in Exhibit Q made some changes to revenue requirement and those are detailed in the evidence. And then panel 1 laid out some changes in revenue requirement related to the Fair hydro Plan, the impact on bad debt. Panel 1 also talked about changes to revenue requirements related to updating for the 2017 actuals, and then the fourth item is the changes in external revenue that we discussed on this panel this morning.

So when you look at the combined impact of all of those items, the impact on all rate classes in 2021 would be a .3 percent, a .3 impact on distribution rates and for a typical residential customer, that's about a .1 percent impact on total bill. That would be for all classes.

Now, because of the adjustment factors, the acquired utilities or these new acquired classes would share in less than that. So in terms of the impact on -- the bill impacts shown on this interrogatory response, we are actually looking at a total bill impact of less than

.1 percent is what we would estimate.

MR. QUESNELLE: Okay, that's helpful. Thank you very much. Okay, anything else Mr. Vegh?

MR. VEGH: No, thank you.

MR. QUESNELLE: That's fine. Mr. Sidlofsky?

CROSS-EXAMINATION BY MR. SIDLOFSKY:

MR. SIDLOFSKY: Thank you, sir. Good afternoon, my name is James Sidlofsky and I am counsel with OEB Staff, and I think I am scheduled for 30 minutes this afternoon with you, I think I will be briefer than that. I have a small number of questions for you.

In your responses to both Staff interrogatories 242 -- sorry. Staff have a compendium and members of the panel have a copy of that. I apologize. I should have entered that as an exhibit and it will be K11.5 (sic).

EXHIBIT NO. K11.4: BOARD STAFF CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 7

MR. QUESNELLE: It's hard to drive the limousine and sit in the back seat at the same time, Mr. Sidlofsky.

MR. SIDLOFSKY: I am doing it all, sir. If I could take you to page 2 of the compendium, you'll find copies of OEB Staff Interrogatory No. 242. That's Exhibit I, tab 49, schedule Staff 242, followed by a copy of Exhibit I, tab 49, schedule Staff 243, your response to OEB Staff Interrogatory No. 243.

And in the responses to both of those interrogatories, it happens to relate to part C of both of those interrogatories, Hydro One said that once the rate freeze period ends for the acquired utilities and their rates are harmonized into Hydro One's rate structure, Hydro One will no longer separately track the costs associated with the acquired utilities.

MR. ANDRE: Yes, that's correct.

MR. SIDLOFSKY: Now, just a question about that. When you say harmonized into Hydro One's rate structure, are you talking about merging the acquired utility rate classes into Hydro One's existing rate classes, or simply about completing cost allocation and rate design with the new classes included?

MR. ANDRE: Absolutely the second one. We are not merging them -- well, the street lights and sentinel lights, there are some of smaller classes that are getting merged with Hydro One classes.

But I am referring to 2021, the year that we create those new rate classes, the six new acquired rate classes.

MR. SIDLOFSKY: Just as an example then, when you are looking at moving Woodstock residential customers into new acquired urban residential rate class, you wouldn't be transitioning those at some point into the existing urban residential rate class. Is that correct?

MR. ANDRE: That's correct, we would not be doing that.

MR. SIDLOFSKY: So they will remain in the acquired urban residential class?

MR. ANDRE: That's correct.

MR. SIDLOFSKY: And is it still your intention to not separately track the costs associated with the acquired utilities?

MR. ANDRE: Yes, that's correct. You are not able to generate the efficiencies that you are counting on within your business structure if you need to continue to separately track, from a work tracking perspective as well as financial tracking perspective, if you need to keep those separate.

So yes, we are still planning to integrate them.

MR. SIDLOFSKY: If I could take you to page 7 of the compendium -- well, really what you will find there is the word no. But to be fair, I should take you to page 6 of the compendium.

And the question in OEB staff Interrogatory No. 265, Exhibit I, tab 56, schedule Staff 265 is -- sorry, in part (b) of that, the question is: Does Hydro One plan to eventually harmonize rates for acquired utilities with the rates for the legacy customer base?

Your answer to that question is no, and you go on to say that you use the -- you plan to use the proposed adjustment factors included in the cost allocation in all future cost allocation runs, so that existing acquired utilities will attract a share of any growth or decline in the total investments Hydro One requires to serve all of its customer base. That's your plan?

MR. ANDRE: Yes, and I think the only refinement to that is both at the technical conference and I think in a subsequent technical conference undertaking, we clarified that perhaps way down the road that there may be a need to revisit the quantum of those adjustments, but certainly not in the next five to ten years.

So this, as I say, was slightly tweaked in that undertaking response.

MR. SIDLOFSKY: Okay. And if we move to page 9 of the compendium, and this is part of your answer to undertaking JT3.26-3, so this was an undertaking from the technical conference, you say that Hydro One's total new capital spending, both within and outside the acquired utility's service territories, will be shared by all Hydro One customer classes. This includes the acquired rate classes who will attract a share of all new capital spending as a result of the cost allocation model's underlying methodology and the use of the proposed GFA adjustment factors. Therefore, there's no need to separately track the costs associated with the acquired utilities.

And that remains your position, correct?

MR. ANDRE: Yes.

MR. SIDLOFSKY: If, for example, Hydro One determined a significant amount of capital upgrades were required in Woodstock, just to name one of the acquired utilities, and those upgrades were much more than the average requirement across Hydro One's service territory, would that increase the costs that feed into the adjustment factors?

MR. ANDRE: No, it would not. So the adjustment factors are developed based on the capital additions that have been made up to 2021, so it reflects the relationship between assets required by the acquired utilities versus Hydro One's total asset base, and those adjustment factors would stay.

I mean, I think people could argue that perhaps, you know, in this case in the example that you just gave, Mr. Sidlofsky, yes, there are -- there would be investments in Woodstock, and so people might argue is it fair that they get just the adjusted share of those investments going to them?

I think other people would argue is it fair that they are getting share of the common costs and shared services per the methodology that we have?

So, you know, I think there is an allocation process that's going on, and that allocation process ties back to the total costs that Hydro One incurs to provide service to all of its customers, and that means that the acquired utilities get a share of things like investments and they share in the investments that are outside their service territory. But by the same token, customers outside that service territory share in the investments that are made within the acquired utility service territory.

So it's essentially the same concept as postage stamps. You then share those costs just as you share the common and shared service-type assets equally among the legacy and acquired customers.

So, yes, there is a sharing and that is our proposal.

MR. SIDLOFSKY: But once you -- once you establish the adjustment factors, you are not contemplating changing them.

MR. ANDRE: No. So investments, investments that are made will -- you know, Woodstock and -- Woodstock -- all of the six new acquired classes will get a share of any new investments that Hydro One makes, whether that new investment is, you know, outside the acquired service territories or inside the acquired service territories, and really it's the only practical way that we could see that you could do that without tracking, you know, without continuing to track the acquired utilities separately, which I think would have large implications that the other panels probably would have been in a better position to speak to. But I know it would have big implications on Hydro One's business if we needed to continue doing that.

MR. SIDLOFSKY: So if I can just take you up a paragraph to part (c) of your response to that undertaking, so also on page 9 of the compendium, you seem to be acknowledging the possibility of an update to the adjustment factors, and I will read a portion of this paragraph. You state in there that:

> "In the long-term, as more of the original assets are replaced at Hydro One's installed capital costs, Hydro One will assess the need to update the currently proposed adjustment factors."

So in part (d) of that response you have said that you are not planning to separately track the costs associated with the acquired utilities, so the question becomes if costs aren't being separately tracked how can you update the adjustment factors at a later date?

MR. ANDRE: So we haven't thought through the precise methodology that would be used, but it would relate to -- and I think I mentioned this before -- it would relate to the end of life of the assets. So, you know, all of the wood poles and transformers and conductor all have an end of life, and as the assets approach the end of life, the expectation would be that they would need to be replaced within the service territory that the acquireds are in, and so understanding how much time has passed and how much of the assets are likely to have been replaced since the time that they were integrated, I think that would be the basis, and it would be something that would need to be proposed to the Board at the time that we suggest a change to the adjustment factors. We would have to defend the methodology, rationalize the methodology. But at this point in time what I think would happen is you would have to defend that methodology based on the length of time that has passed and the likelihood of the assets within those acquired utilities having been replaced and now being at Hydro One's installed costs, as opposed to the original installed cost.

MR. SIDLOFSKY: Okay, thanks, Mr. Andre.

A few questions -- a very few questions about specific service charges. Could I take you to page 15 of the compendium. This is an extract from Exhibit E1, tab 1, schedule 2, and specifically it's page 9 of 20. There was some discussion earlier today about an updated approach to some of the specific service charges, but what I am going to touch on here is Hydro One's statement in Exhibit E1, tab 1, schedule 2 that it expects the volume of many specific service charges to decline as more customers move to online self-service tools. That's your expectation; correct?

MR. BOLDT: Yes.

MR. SIDLOFSKY: Could you tell me what Hydro One is doing to promote the use of those self-help options and, I guess, in relation to that, what you are doing to assist customers in avoiding the use of services where they can?

MR. BOLDT: Well, I think my colleague Imran Merali spoke of this earlier in the week. It's more under his shop, if you will, but it's my understanding that when customers do call looking for services, they do direct them to the web portal to try to allow them to go and get their own information. I do believe that there's bill stuffers. I think there's notices as well that they are doing to try to just notify people of the options that are available.

MR. SIDLOFSKY: So it's bill stuffers that --

MR. BOLDT: I believe it's more than that, but it's certainly not my -- it would be better directed to Imran Merali, this question.

MR. SIDLOFSKY: Okay. Is it fair to say that you are taking steps to let customers know about their self-service options?

MR. BOLDT: Yes, I believe they are even from earlier discussions earlier this week that I heard Imran say that they are actively notifying people, yes.

MR. SIDLOFSKY: Okay, I am going to ask just a couple of questions to conclude about rate code 16. And that is -- that's the collection of account charge with no disconnection. And you're proposing that that charge would go from $30 -- and, sorry, I will take you to page 19 of the compendium. And that's an extract from Exhibit H1, tab 2, schedule 3. And we see that rate code 16 is proposed to increase from $30 to approximately $96, $95.65.

At what point in the arrears or disconnection timeline would that charge apply? So if I take you to the last page of the compendium, page 23, this is your response to OEB Staff Interrogatory No. 4, Exhibit I, tab 2, schedule Staff 4.

So we have a timeline, and I think I actually had a bit of a discussion with Mr. Merali, or one of the parties did, about this lengthier process before you actually get to disconnection, the timeline that's at the top of the page.

So my first question would be, where on that timeline would that charge be imposed?

MR. BOLDT: Okay, first off, on the -- on page 13 that you directed me to, these are 2016 costs from the time study. The 2018 charge for this same code is found in H1, tab 2, schedule 3, page 5 of 112. And it's actually going -- for 2018 it's going to $100.

Based on what's on the screen right now, the charge does not get charged until after the disconnection. So when it's physically disconnected is when this -- oh, I am sorry, no, let me back up. This is a collection, no disconnection.

MR. SIDLOFSKY: That's right.

MR. BOLDT: So at the point that they go to the disconnection, so all the way through where there is a door hanger hung, disconnect letter done, live call made, then what happens is the disconnect order is issued to our field staff. At that point they will roll a truck today if there is not a disconnect meter on their remote disconnect meter, and it's when the person arrives in the yard to discuss to the customer that they are going to disconnect them that day, and the payment is made, then that is when this gets -- there's a physical trip to the yard where the collection's paid on that day, and that's where this would be applied.

MR. SIDLOFSKY: So the charge -- sorry, so the charge is only applied when there's a truck roll?

MR. BOLDT: Currently, yes. Our cost on this study that we did, it was for truck rolls, as I mentioned earlier today. And like Mr. Merali has said earlier, what they are doing is if there is a physical disconnection of the service at a meter they are deploying remote disconnect meters, so that when the reconnection happens they don't have to roll a truck again.

So this would be in a situation where we actually physically do a truck roll and get to the site and the customer pays us or makes arrangements and we don't physically do the disconnection on that day.

MR. SIDLOFSKY: Okay. So just so I am clear on that, if I get to -- if I am your customer and I get to the disconnect letter stage or the live call stage I won't be charged that $100?

MR. BOLDT: No, it's not until someone comes to the site.

MR. SIDLOFSKY: Okay. If you can just bear with me for a moment, Mr. Quesnelle.

MR. QUESNELLE: Okay.

MR. SIDLOFSKY: In the conversation this morning about certain rates not going up, the question is why is this particular rate going up based on the study where you're not proposing to change other rates?

MR. BOLDT: So if you were to follow this process in a situation like we spoke of this morning or earlier today with the remote disconnect meter, what will happen -- and it's forecast that upwards half of the meters at some point will have remote disconnects or more than that on them. After the 48-hour call, the live call, the disconnection's going to happen automatically from our central call centre, or wherever it will be.

The proposal here is that it would still go up because if you are in a location where the remote meter isn't located, or basically there's no remote disconnect meter on the service, we are physically now driving to this location to actually do the work. And at this point, that's why we are proposing that you would have to still charge that cost, to recover the cost of that roll of the truck.

MR. SIDLOFSKY: Because you are actually signing assets and going out there and doing it.

MR. BOLDT: Correct.

MR. SIDLOFSKY: As opposed to doing everything remotely or from your call central or a central location.

MR. BOLDT: Correct. So this would only take effect if there wasn't a remote ability to disconnect that service.

MR. SIDLOFSKY: Okay, thank you. Those are my questions, thank you, panel.

MR. QUESNELLE: Thank you, Mr. Sidlofsky. Ms. Keon?

CROSS-EXAMINATION BY MS. CHIDICHIMO KEON:

MS. CHIDICHIMO KEON: Yes, thank you, and good afternoon. My name is Ada Keon and I am here on behalf of the City of Hamilton. I just have a few questions about street lights.

I have a compendium. Can I ask that it be made an exhibit at this timer?

MR. QUESNELLE: Mr. Sidlofsky?

MR. SIDLOFSKY: Sorry, that allows me to correct my other numbering. K11.4 was the Staff compendium. K11.5 will now be the City of Hamilton compendium.

MR. QUESNELLE: Thank you.

EXHIBIT NO. K11.5: CITY OF HAMILTON CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 7

MS. CHIDICHIMO KEON: So to begin, I would like you to turn to tab 1, page 1, and at the top of the page, you will see table E4 which is from the pre-filed evidence.

I take it that this table is intended to show the number of customers, historical and forecast, that contributed to Hydro One's load forecast.

MR. ALAGHEBAND: That is correct.

MS. CHIDICHIMO KEON: And would you agree, subject to check, that for the period between 2017 and 2020, the forecast is that the number of customers will grow by only about 2 percent for the street light rate class?

MR. ALAGHEBAND: I should mention that the 2021 and '22 includes the acquired street lights.

MS. CHIDICHIMO KEON: Yes.

MR. ALAGHEBAND: It looks correct, yes, approximately.

MS. CHIDICHIMO KEON: And so if we turn to page 2, then, I understand that this is table E6 and it shows Hydro One's actual sales and forecasted sales in gigawatt-hours for its various rate classes.

MR. ALAGHEBAND: That is correct.

MS. CHIDICHIMO KEON: And would you agree with me that the values for the period up to 2022 are essentially flat, with the exception of the acquired utilities in 2021 and 2022?

MR. ALAGHEBAND: That is correct, yes.

MS. CHIDICHIMO KEON: And then turning one more page to page 3, at the bottom half of the page on table E9, this is from the pre-filed evidence and it shows Hydro One's calculations of the CDM impacts by rate class.

MR. ALAGHEBAND: That is correct.

MS. CHIDICHIMO KEON: And this calculation is done because CDM programs impact the rate class?

MR. ALAGHEBAND: These are standard CDM rate class impacts. Yes, we had -- for all these categories we had a CDM amount, so it's shown here. For example, for distributor generation, it doesn't apply so it doesn't show up.

MS. CHIDICHIMO KEON: But in general, these figures are here because the assumption is that CDM programs have the effect of reducing consumption and reducing sales?

MR. ALAGHEBAND: That is correct, yes.

MS. CHIDICHIMO KEON: And you have acknowledged in the evidence that the City of Hamilton has a CDM program in the form of an LED conversion for street lights?

MR. ALAGHEBAND: That is correct. We had a CDM program there and we are continuing having that one. And then there is -- as I mentioned earlier, in CDM fields that you see here, these are the standard CDM categories which were identified in things like LTEP, things like Ontario Power Outlook -- planning outlook. But we didn't have a standard category for street lights. The street lights were always -- there was nothing assigned to that.

And as I mentioned in many responses before, that CDM is taking into account in terms of implicit CDM in that historical views.

MS. CHIDICHIMO KEON: So going to that notion of implicit calculation which you have mentioned before in the undertakings --

MR. ALAGHEBAND: Yes.

MS. CHIDICHIMO KEON: -- could you explain what that means, an implicit calculation?

MR. ALAGHEBAND: If you go back to response to undertaking JT1.1...

MS. CHIDICHIMO KEON: Yes, I believe I have that in the compendium on page 4.

MR. ALAGHEBAND: Oh, yes, okay. So if you go back to that one, the answer is that in response to undertaking number 4(c), we see that there are two components related to street lighting. One is how much load is increasing, and the other one is how much number of customers or number of street lights are increasing.

So during this period, during the historical and forecast period, of course we are forecasting that the number of street light customers will increase, and that increase would imply new load coming to the system. But at the same time we have efficiency improvements, like what we did in City of Hamilton, that would has a negative impact on the load. So we have a negative impact on the load because of the efficiency improvements, and we have a positive impact because of the increase in number of customers.

So to figure out that how much implicitly was saving there, we need to do a little further calculations, and I did some already, so that we can save time on this hearing. If I get your attention back to Exhibit E1, tab 2, schedule 1, which is the main forecast document, and we go to page

39 -- I think these tables are also shown in your compendium, but I did my calculations on that basis. So you can refer to your compendium on this one if you refer us to where is the corresponding table for E4, or we can look at it here, yes.

Table E4 is on page 39. You can see, for example, on this table, for the period that we had all these improvements, efficiency improvements, the number of street light customers went up from 4,724 in 2012 to 5,286 in 2017. That reflects almost a 12 percent increase in the number of customers.

I should make one more qualification here and it's that this number of customers doesn't -- this 12 percent doesn't really reflect total number of increase in street lights, because some of -- when we call a street light customer we are referring to contracts. For example, the township may have only one contract, and within that township if the increased number of street lights, the number of contract doesn't change, so it has no impact on number of customers. So the 12 percent increase that you see is the minimum increase in the number of customers that we observe for street lights.

MS. CHIDICHIMO KEON: So just to clarify for myself, then, so you are saying that the 12 percent increase in Table E4 is a calculation which has already taken into account the efficiencies of, I believe 22 gigawatt-hours that have been identified previously?

MR. ALAGHEBAND: Well, let me explain more. This is

-- in Table E4, we are just only showing the total increase in number of customers. So my conclusion is that if you were going to have same efficiency for our street lights, the gigawatt-hour, the sales in the street light should also -- would have been increased by 12 percent, whereas it didn't. If you go to table, just a little, scrolling down to Table E6, for example, we see that from 2012 to 2017 the load actually went down from 127 to 121, reflecting 5 percent drop in the load.

So on one hand number of customers are increasing by 12 percent, but the load is going down by 5 percent. So if we see what is happening to consumption per number of street customers, per street customer, the actual efficiency improvement has been 12 plus 5, which is 19 percent increasing efficiency.

So that is what you call implicit efficiency improvement. You see number of customers going down, but load going down. It means that there has been efficiency improvement.

Now, if you multiply that 19 percent improvement times 127 gigawatt-hours, it's about 22 gigawatt-hours, this is the 22 gigawatt-hours that we were actually mentioning, and you were actually mentioning that as being the savings during that period. So actually, the numbers match, and we believe that there has been more efficiencies actually going on. It's not reflected here, all of that, and that is compensated by, as I mentioned earlier, the number of customers grow, actually doesn't reflect the total increase in number of the street lights, but anyways, we have the 22 gigawatt-hour efficiency that we're improving, that we were talking about is already there implicitly.

MS. CHIDICHIMO KEON: Implicitly, okay.

MR. ALAGHEBAND: Yes, that's --

MR. QUESNELLE: Can I just interject for a second. Mr. Alagheband, you -- did I catch you right that you are looking at the street lights at the Table E4?

MR. ALAGHEBAND: Yes.

MR. QUESNELLE: That that's the number of contracts?

MR. ALAGHEBAND: Yes, a customer for us is number of contracts that we have, so we count number of contracts. For example, I am aware that for City of -- for Haldimand we have only two contracts.

MR. QUESNELLE: So --

MR. ALAGHEBAND: It --

MR. QUESNELLE: So there isn't a -- you are saying 12 percent at a minimum because the number of contracts have gone up, so that assumes that each contract had one street light, or 1 percent rather --

MR. ALAGHEBAND: Well, if you had -- sorry, my point was the other way around. I am saying that for the township we had one contract, and number of street lights in that township goes up, that one stays one, so it doesn't show any growth --

MR. QUESNELLE: I'm just asking --

MR. ALAGHEBAND: -- street lights are going off, actually.

MR. QUESNELLE: That does confirm my understanding of what you said.

MR. ALAGHEBAND: Oh, okay.

MR. QUESNELLE: So to correlate this properly, do you have another layer of granularity? Did you have a total street light population?

MR. ANDRE: Yes, we do, and so the cost allocation model actually references the number of street lights. That number is what's used in the -- well, we use both. We use number of contracts for the purpose of bills that are sent out, but for the other allocation we use the number of street lights, so it is in there.

MR. QUESNELLE: Okay, thank you.

MS. CHIDICHIMO KEON: And so just to confirm then, although, you know, you have the 22 gigawatt-hour savings that you have calculated, that number isn't going to be reflected in Table E9 because it is not a standard rate class that you include in that chart?

MR. ALAGHEBAND: Yeah, that's the problem, you know, that when we are allocating the CDM into different rate classes we have to have a category, a standard category for that, based on things like LTEP, things like Ontario Planning Outlook, and we don't have that category there, we have a special program, and we got the approval from IESO to do the street lighting savings, but they still don't show that as a separate category of CDM, whatever you may call it, as a CDM.

MS. CHIDICHIMO KEON: Okay. And so -- so this data is what we have, because you will understand that from my perspective or from the client's perspective when you look at these tables together, when you see the flat load growth, what essentially looks fairly flat plus flat sales growth, and not seeing any CDM accounted for in Table E9, it's hard to understand the impact of a CDM program.

MR. ALAGHEBAND: I completely understand that, yes, I understand.

MS. CHIDICHIMO KEON: So in the technical conference undertaking response that is on page 6 -- I believe we have referred to it already -- you say that you do not forecast specific CDM amounts, although there is the 13 gigawatt-hours of savings from 2018 to 2022, and this appears to be a forecast. What data was used as the basis for this 13 gigawatt-hour figure?

MR. ALAGHEBAND: Okay, for -- again, we are looking at the trends in number of customers and the sales. We were looking at those figures just a minute ago.

So we look at those trends and test the dynamics of that over time and come up with a forecast of number of customers and load in the future. So again, we have a kind of implicit method of forecasting those future, say, gigawatt-hours of street lighting.

MS. CHIDICHIMO KEON: And is this data available or could it be produced?

MR. ALAGHEBAND: It is already there. You already see that, what is the gigawatt-hour load, and you see how much is the share of the street lighting in total load, so we have it, and we take that into account going forward.

MS. CHIDICHIMO KEON: Mr. Chair, I know that we are getting close to the scheduled break time. I can stop here and take back up on another subject once we come back if that's --

MR. QUESNELLE: No, carry on if that --

MS. CHIDICHIMO KEON: I don't have much longer.

MR. QUESNELLE: Okay, thank you.

MS. CHIDICHIMO KEON: So I take it that the rates for the street light rate class, they are not just the rates for the city of Hamilton, you have other street light customers?

MR. ALAGHEBAND: That is correct.

MS. CHIDICHIMO KEON: And how many other customers do you have?

MR. ANDRE: That figure, the 5,000, represents the number of contracts. You know, some contracts, like Mr. Alagheband said, are with the city that have many lights, other contracts are with customers who maybe just have a few lights.

So in terms of the number of customers' contracts, that 5,000 figure would be the best estimate of a customer, a street light customer.

MS. CHIDICHIMO KEON: Okay. And when you're developing the rates for the street light class, do you consider whether each of those customers or contracts have CDM programs associated with them?

MR. ALAGHEBAND: Again, the method that we are using is the implicit method, because for the ones that we have a control on, and I think that is the one which is already reflected in the savings that we were talking about, those things are implicitly taken into account. And that is the only way we can do it. We cannot, based on -- we have the actual number coming out of our billing system, and we cannot change those figures, saying that, oh, well, what would have happened if it was otherwise or something.

So we take that into -- those billing numbers are already reflecting the trends in that, and we take that into account going forward.

MS. CHIDICHIMO KEON: So my question is that when you are calculating these rates for the street class, presumably there are different customers that have different CDM programs in place, and these are being bundled together; is that correct?

MR. ALAGHEBAND: As long as Hydro One street lighting load is concerned, these are all Hydro One customers, so all the efficiency improvements is something that is reflected already in Hydro One data, so we don't need to actually go and ask each of these customers what is happening, so these are all Hydro One load, actually.

MR. ANDRE: Yeah, what I would actually add, though, is -- so with street lights we rely -- and we now have a process to contact street light customers on an annual basis, and we rely on them to advise us of efficiencies that have been implemented, so that then gets reflected in our actual billing. And then as Mr. Alagheband said, once it's reflected in the actual billing, the historical data will show whether there's a trend in, you know, a decreasing trend in the consumption.

So when it comes to street lights, we do rely on our customers to advise us of changes to their consumption from efficiency or whatever other purposes.

MS. CHIDICHIMO KEON: Right, and as you said, there is hopefully an a net efficiency. But my question is -– presumably, there are some customer who is do not have any types of CDM programs in place, and so they might not be achieving any efficiencies; is that fair to say?

MR. ALAGHEBAND: It is possible.

MR. ANDRE: Yes.

MS. CHIDICHIMO KEON: So a customer who does have a CDM program in place, but who is -- the effect of that could be diluted by other customers who do not have similar programs in effect; is that fair to say?

MR. ANDRE: Yeah, I mean, I think those customers who have those efficiency programs, what they will see the benefit of is once they communicate that change in load, the street lighting load to our billing services, what they will see is the rates remain as they were set on the assumption of whatever street light consumption was built in at that point in time when the rates were set.

If now, over the period of the application, if they generate efficiencies and they communicate those efficiencies to our billing group, they would actually see the benefit of lower rates because their lower consumption would then be applied to the rates that have been fixed at a certain point in time.

MS. CHIDICHIMO KEON: Right. I understand they would benefit from the lower consumption rate. But I am wondering how a customer can evaluate the effect that their CDM program has on the actual structure of the rates, not just the volumetric charge.

MR. ALAGHEBAND: Let's put it this way. When there is only one, say, single customer out of those 5,000 does something, it would barely have any effect on the rate. It would be a little -- it would have some effect, but it would be very unnoticeable, okay. But the main benefit that they get is first of all, they pay less for commodity charge, they pay less for the volumetric charge of the distribution charges.

But one customer at a time, I mean, it is a little bit, you know, different -- I mean, it's difficult to configure that one township, for example, would make, for example, a 10 percent efficiency, so then all the Hydro One rates would chain.

No, it would have some effect, but it would be a small change.

MR. ANDRE: From a cost allocation perspective, you know, until that volume of street light customers become significant enough, which would be picked up in the trends of the historical data that Mr. Alagheband uses for his forecast, at that point you would start to see a potential impact on cost allocation and rate design. But any one individual customer, it wouldn't have a material impact on cost allocation or rate design.

MS. CHIDICHIMO KEON: But would the data be available for that one individual customer to see even a very marginal effect of their CDM program on the cost allocation rate design? Is that data available at that level of granularity?

MR. ANDRE: So the inputs to the cost allocation model are the total consumption based on historical data, forecast forward per Mr. Alagheband's methodology, and that would be the input into the cost allocation model. You wouldn't have it at the granularity of an individual customer, no.

MS. CHIDICHIMO KEON: Just one moment. So could Hydro One report for each year of the IR regime -- I believe the answer is no, but the IR regime the actual and forecast CDM savings for each member of the street light class?

MR. ALAGHEBAND: Actually no, no we cannot.

MS. CHIDICHIMO KEON: And can Hydro One report, for each year of the IR regime, the forecast CDM savings for each member of the street light class for the remaining years of the IR regime?

MR. ANDRE: Not unless they have specifically advised our customer service centre that their consumption is changing. So it would be reflected in the historical data or -- sorry, in the actual billing data, billing determinants for an individual customer. But the customer would be aware of that, because they would have been the ones communicating to us about their change.

MS. CHIDICHIMO KEON: And can Hydro One report, for each year of the IR regime, the impact on the proposed rates for the street light class of the actual and forecast CDM savings?

MR. ALAGHEBAND: I believe we did that --

MS. CHIDICHIMO KEON: We spoke act that already, actually, so that's okay.

MR. ALAGHEBAND: They're based on figures that were provided before -- let's go back. I think it was asked in one of the -- okay here it is.

So if you go back to Exhibit JT1.1, on page 8, actually this question was asked and we provided that if you go to the table which is shown on that table on the response -- oh, you haven't got it yet.

Yes, this is the table and as you can see, we are showing sales net of CDM in the first column, and just beside that, we are showing sales gross of CDM. The difference is the CDM impact.

MS. CHIDICHIMO KEON: Yes, but that's not broken out by individual customer.

MR. ALAGHEBAND: It cannot be by individual customer, no, sorry.

MS. CHIDICHIMO KEON: Okay. And, again, we touched on this already, so just to conclude, can Hydro One report, for each year of the IR regime, the impact on the street light rates the city pays of the savings actual and forecast from its LED conversion program?

My understanding based on your earlier responses is that these are bundled and so for an individual program, it's not possible to tell the impact on the rate design; is that correct?

MR. ANDRE: The impact on the rate design, no. I mean, the impact on the rate design wouldn't be felt until the next opportunity to reset rates as part of the next application, and at which point we would again use the actual total street lighting load plus the forecast for that period of the application, and set rates on that basis.

So the impact on rates wouldn't be impacted during the period of the application by any changes to a particular customer's use of street lights, or efficiency programs on that street light.

But what they could calculate, as I have indicated before, is to the extent that they have efficiency, they would know the rates that are in place and would be in place for the period of the application, and they would be able to apply those fixed rates to whatever savings they forecast and then be able to calculate the savings both on distribution rates, commodity and all of the other bill components.

MS. CHIDICHIMO KEON: Right. We are primarily focussing on the volumetric charge.

MR. ALAGHEBAND: May I also add that -- actually, you can do all this calculation, so you can measure how much savings, for example, are there per lamp and multiply that by the savings that you make in terms of volumetric charge, commodity charge, to see how much savings you are making.

But in terms of how much of how much you were affected by that efficiency improvement program, how much you affected the street light overall rates, that would be a very minimal amount. So I don't think that would be actually something that would be of use to you.

The thing which is of use to you would be how much savings you are making; isn't that correct?

MS. CHIDICHIMO KEON: Well, I think it's to see the savings in terms of how the rate is structured. You would hope that by implementing an LED conversion program, you would benefit from lower rates.

And I am still having trouble following the example you gave in table E6, because -- and correct me if I am wrong, but would these numbers be higher if you had not already taken into account the effect of the CDM savings?

So we have these under table E6, just for example, the actual sales and the forecast gigawatt-hours, and we have spoken about them. They're 125, 127, 125; would those numbers have been higher but for the implicit calculation that had been done?

MR. ALAGHEBAND: We already went through that. I already was showing that if sales -- we consider sales growth of CDM, the numbers will have been much higher.

MS. CHIDICHIMO KEON: Right, and would those numbers be available, just so we could follow?

MR. ALAGHEBAND: I already gave you the numbers.

These are in Exhibit JT1.1. These are CDM sales. If we didn't have any CDM savings -- I mean, the gross sales that we are showing here is what would have been the load in the absence of CDM. We cannot say what the -- on the other hand sales for net of CDM is the correct version. This is based on historical trends. We believe that this is correct.

MR. ANDRE: And it would be those values net of CDM that would actually be used to establish the rates for that class.

MS. CHIDICHIMO KEON: Right, and -- okay. I see. And as you already said before, they are done on an aggregate amount.

MR. ANDRE: On aggregate amount and at the time of rate application, correct.

MS. CHIDICHIMO KEON: Okay. All right. Thank you very much. Those are all my questions.

MR. QUESNELLE: Thank you, Ms. Keon.

QUESTIONS BY THE BOARD:

MS. ANDERSON: Sorry, just a few follow-ups so I'm clear on how we deal with street lighting. So in your rate design tables I think you show again the number of customers for street lighting, but I believe on your tariff it would be per connection that the service charge would apply; is that correct?

MR. ANDRE: Yeah, the service charge applies per contract.

MS. ANDERSON: Per contract?

MR. ANDRE: Yeah, per contract.

MS. ANDERSON: Are you sure that's what's on your current tariff?

MR. ANDRE: Well, the -- because the -- and as you know, I think there were standardized language applied to all of the tariffs, and I know that for -- well, let's have a look. But we don't have the ability to levy by connection, because we don't have information from each customer on the number of connections they have. And certainly when we calculate the fixed charge, we take the fixed charged revenue to be collected and we divide it by the number of contracts. So we divide it by the number that we are going to bill on.

So I can tell you that it's billed on contract, and it may refer -- does it refer to connection? Yeah, we are on the same -- I think you were asking does the language -- and if it says this would be the opportunity, I think, to clarify that and make sure it refers to -- I just want to see...

So the service charge, it simply says service charge, and a dollar, 4.07 (sic) is our proposed charge. There is no reference to per connection.

MS. ANDERSON: Right. That's your proposed. I guess I was -- I was seeking clarification on your existing, just to see whether that -- you know, if that's some typographical error or -- but you are saying it's based on contract, because you don't have connections --

MR. ANDRE: Yes, it's consistent with the way the rate is calculated.

MS. ANDERSON: Okay, I will let you finish that --

MR. ANDRE: Yeah, the rate is calculated on a per contract basis, so we apply the charge on a per contract basis.

MR. LI: I can confirm that the existing -- or the current approved rate schedule has the same wording.

MR. ANDRE: Just service charge --

MR. LI: Service charge, and it's $4.25 is the same definition.

MS. ANDERSON: Okay. My favourite topic of LRAM. In Exhibit E I see the CDM savings. There's a table for those, but they are on a total basis. Do you have that broken down by class for the purposes of the LRAM VA? Because if so, then you would have the CDM adjustment for street lighting, because that would be with the classes, right --

MR. ALAGHEBAND: Yeah -- okay. For LRAM VA, for E9, in Table E9, on the main application, we had by rate class, so it's simply -- by rate class it's standard rate classes, so we don't have, actually, any CDM category, official CDM category, for street lights. It's something like, you know, it is implicit in the forecast already for the --

MS. ANDERSON: I -- so this -- sorry, just so I am clear, then the purpose of E9, those are your are CDM targets for the LRAM.

MR. ALAGHEBAND: Yes, yes.

MS. ANDERSON: So you don't have a -- okay. That's what you mean by you don't have an implicit one for a street light --

MR. ALAGHEBAND: Yes.

MS. ANDERSON: Okay.

MR. ALAGHEBAND: Yeah, these are actually -- okay. Clarification also. These are total CDM amounts. So CDM reflects the code and standards reflect and also energy efficiency effects, so these are not really for the -- these are not really used for the purpose of LRAM. For purpose of LRAM for rate category is given another -- another exhibit for Exhibit JT3.18-4.

And if we go to page -- if we go to page 3 -- yeah, that's -- these are the rate classes that would be -- is proposed to be in the LRAM VA threshold by rate class.

MS. ANDERSON: Okay. I apologize -- ask you to repeat what I am sure you have answered, is why is there not one for street lighting?

MR. ALAGHEBAND: The street lighting is implicit in the forecast already. It's not an explicit calculation of that one, it is implicit in the forecast.

MS. ANDERSON: Okay, thank you.

DR. ELSAYED: I just have one question. Mr. Andre, you said that you do not track the cost of the acquired utilities separately. Did I understand that correctly?

MR. ANDRE: Currently we do. Up to the time of harmonization as per -- or up to the time of the first application I think was the direction from the Board that we were to track the costs separately so that we could identify the savings and identify the specific OM&A and capital spend associated with the acquireds.

But past that first application filing there is no requirement to track the acquired utility cost separately, no.

DR. ELSAYED: So you would have no way beyond that point of demonstrating that those savings and efficiencies continue to occur?

MR. ANDRE: Yes, that's correct. There's a certain period per the MAADs process where the rebasing is deferred, but then once rebasing occurs then it's all one integrated utility and there is no need to continue tracking those differences, including any savings differences.

DR. ELSAYED: But you do expect those benefits to the ratepayers to continue to happen beyond that point?

MR. ANDRE: Absolutely. The benefits to the ratepayers have built in -- have been built in by virtue of the adjustment factors that are part of the model, and those adjustment factors would continue, yes.

DR. ELSAYED: Okay, thank you.

MR. QUESNELLE: Just continuing on with that line, in the associated -- the acquired associated MAADs applications, the creation of Hydro One's evidence, I am just interested in the methodology and how that methodology compares to the use of the cost allocation model because, as I recall, the analysis that led the Board to conclude that the no-harm test had been met was based on an analysis of cost to serve on density levels, comparable density levels.

So if there was an analysis available to determine what the similar density levels would be in a Hydro One area and that was used as a comparison to the existing cost in the proposed acquired entity, how does that differ now and why can't that be used to determine a rate, as opposed to the cost allocation model, the feed-ins, which, as you have described, is Hydro One as a whole, and then you are backing out certain assets to recognize the local asset requirements versus Hydro One as a whole.

So I am just interested in the cost structures that were used to determine whether or not the no-harm test had been met. What's the utility of those -- of that analysis today when we are setting rates?

MR. ANDRE: So Mr. Quesnelle, I am not as familiar with what was included in the MAAD applications. I do recall, though, and I think this is what you are referring to, that in that application we would have given a per-customer cost for an R1 customer, and we compare that to the per-customer cost for an average acquired utility customer at the time. Is that what you are referring to?

MR. QUESNELLE: I forget it if it was R1, but it was about density.

MR. ANDRE: Or I think for Woodstock, we might have used a UR customer.

MR. QUESNELLE: Correct.

MR. ANDRE: I have a hard time without looking at the details of what was submitted with the MAAD application. I know that information was provided. I had thought the basis for deciding, you know, is there no harm, I thought it related more to the total costs of Hydro One.

But I do recall -- and I think we have talked about those costs have gone down, but I do recall the reference to specific utility, specific classes. The reality is that allocating it to -- allocating it to the acquireds to one of those classes would result in higher rates than the keeping them as a separate acquired class.

MR. QUESNELLE: I guess my point is more to the analysis that informed the Board on what it would expect in future reflection of those cost structures in rates. And I think that's what the Board said, was that there was an expectation that the underpinning costs that were demonstrated to be lower in the MAADs applications would be reflected in the rates. And I am not seeing any analysis that goes back to that same analysis that led the Board to that conclusion.

MR. ANDRE: I would agree there isn't analysis to that. There is an analysis -- I mean, the data on the cost to serve for a typical R1 customer, or any typical customer in any of the classes, can be extracted from the cost allocation results that have been filed.

But there is in comparison to what Hydro One is proposing to charge the acquired customers. What is provided is a comparison of the rates that these customers in these new acquired classes will face, and I have gone over that and I think it demonstrates that, you know, whether you are comparing to their current frozen rates or what their rates would have been if they had not been acquired, and I think that comparison of rates clearly shows that there is a benefit to customers.

But I take your point about the comparison on a cost basis isn't there.

MR. QUESNELLE: And Dr. Elsayed just asked if you were tracking costs now and, as you've suggested, that as the Board required, that there is a tracking of costs separately as was now, and that was to inform the Board as to whether or not those cost savings had occurred, and also to inform the setting of future rates.

And yet I don't see any of that analysis.

MR. ANDRE: The tracking of costs, the incremental costs to serve each of the acquired classes is provided in evidence.

MR. QUESNELLE: It's not going into your rate-making methodology.

MR. ANDRE: Right, the actual costs, because the only costs that are tracked, Mr. Quesnelle, would be the incremental costs. There is no -- there is no tracking of how much of our shared costs are attributable to the acquireds, because they are part of our integrated -- Hydro One's integrated costs until such time as the acquireds come in.

And at that point in time, we have to have a way to say, okay, how much of those shared costs that you provide

-- whether it's billing, or your back office functions, your HR, your finance functions, how much of that should be attributed to the acquired utilities, that happens at the cost allocation stage.

The only costs that are tracked per the Board direction until such time as they are integrated is the incremental costs, and those costs are provided in evidence.

MR. QUESNELLE: And is there any way to combine those two exercises? Wouldn't it just be a cost much like you would have a -- and I am thinking of a comparison to the gas utilities, where they have zonal pricing. You've got a cost to deliver in a certain area and those costs are tracked, and the then there is the overlay of the corporate costs that goes across on a cost allocation basis that would have those common costs shared, but the local costs are tracked separately.

MR. ANDRE: Right, right. So as I say, in the cost allocation model -- I mean, it hasn't come up in evidence so far, but it is in the evidence and certainly we can deal with that in argument, if it's helpful.

But what is in evidence is the amount of OM&A cost. So in the cost allocation model, there's three lines of OM&A: distribution OM&A costs, customer service OM&A costs, and admin in general OM&A costs. And if you look at distribution and customer service, those really represent the incremental -- the equivalent of the incremental OM&A costs.

So we could do a comparison of that, but there would with no way -- as I say, because we don't track the OM&A costs associated with admin and back office-type costs, so there's no way to break that out of those -- out of those OM&A costs that are allocated by the model.

But we can certainly do a comparison, and I think if we did that, what we would see is the cost allocation model is actually allocating slightly less than what we say are the costs to serve the acquired utilities.

Mr. Quesnelle, we won't have those costs going forward and that's part of the problem. Unless we are willing -- unless we commit to tracking those costs forever more on a separate basis, come the next application, how would we identify the OM&A costs specifically associated with serving the acquireds.

The approach that we have proposed using the adjustment factors lets us do that. As Hydro One's overall costs go forward, we have rebased at this point in time, trued it up at this point in time, and if what you are suggesting is could it be trued-up even better -- in other words, look at the OM&A costs assigned by the model and actually true that up to the OM&A costs that you've been tracking and you've identified as being associated with the acquired utilities, that could be done. But there is a bit of a mismatch because all we are tracking is incremental versus what you really need to charge them is the incremental plus a share of the common.

MR. QUESNELLE: So the methodology used to track the costs that the Board requested then doesn't allow you to project -- not project, create rates for acquired on an ongoing basis. Your proposal is to do away with that and have it on an adjusted global cost allocation model results.

MR. ANDRE: Yes. The methodology that's now -- and I don't know how a utility could do that, how we could even estimate how much of your shared costs -- you know, five or ten years down the road, how much of your shared costs would flow to the acquired utility.

You might have an handle on the incremental cost to serve that acquired utility, but I don't know that -- essentially, what you would have to do is do some form of allocation of the shared costs at the time you are putting your acquired application together.

MR. QUESNELLE: I am not asking you to, if you have no knowledge of how they go about it. But I'm making the comparison to zonal cost in gas, where you have a company -- Mr. Shepherd took you earlier to the example, I suppose, of a holding a company separate in Brampton. But would you agree that you need not have a separate company to have separate books and records.

And you have spoken to the loss of efficiency having ring fenced financing around a particular area. So is that the barrier that would stop you from moving to one that reflects local costs using the analysis, or the projected savings that were provided in the MAADs applications to begin with?

MR. ANDRE: I think that's part of it. And I think you'd also run into issues in terms of -- so you'd no longer have the Board's cost allocation model with the embedded principles that are part of that model as the basis for allocating those shared costs.

MR. QUESNELLE: Unless you had a cost allocation model for the acquired, and a global one that would have the common costs spread across but then cost allocation within the acquired class.

MR. ANDRE: Right. So there would have to be an initial step to say how much of your common costs get put into the specific model that applies to the acquireds. And so what would be the basis for saying how much of those common costs should be part of the acquired-specific -- the acquired stand-alone model.

MR. QUESNELLE: Right. So it would be the same methodology, a customer account or whatever.

MR. ANDRE: Exactly.

MR. QUESNELLE: Understood. Okay, thank you. One for Mr. Boldt and this is just a minor one, but I just want to better understand the time study that was done.

Using Board Staff compendium from today, that's K11.5 and if we could just go to page 13 of 14.

MR. SIDLOFSKY: Sorry, sir, K11.4 is the Staff.

MR. QUESNELLE: Yes, sorry, there was correction there, thank you. Okay.

If we start on page 13, and just rate code 18. We have collection -- under the heading "collection", "disconnect/reconnect at meter during regular hours", and looking at the underlying cost study of 2016 of $114.54. You see that? And then go over to rate code on page 14, 31(a), and just the "vacant premise move-in with reconnect at electric service at meter".

From a truck-roll perspective those look to be the same thing to me. What -- could you describe why you would arrive at different -- in different amounts for those two, reconnect due to disconnection at a pole or a reconnect at a vacant building on a pole?

MR. BOLDT: Sorry, just for clarity, you are saying it's at the pole, so is it 31(b)?

MR. QUESNELLE: I'm sorry. You know what? My comparison is actually with the meter.

MR. BOLDT: Oh, the meter. Okay --

MR. QUESNELLE: Yeah, number 18 at the meter. I think it holds true for both. If you look at both of them -- I brought you to the meter one first, so the number 18 and number 31(a).

MR. BOLDT: Yes. So if we actually go to the study itself -- and I will just take a second. I will get you a reference. Okay. So first we will go to, sorry, this study, which is -- it's Exhibit H1.02.03, attachment 1. And in particular we will start at table 13 on page 44. Sorry, what's that? Yes. Okay. And in particular, if you go to page 45, please, table 15. Okay.

So in our study -- and there was some minor differences that we did see in this, but it was what we found and it's how we recorded it. So in table -- in the underlying cost description under table 15, it's covering both the collection disconnect at the meter during regular hours, as well as the installation and removal of the load control device, which is something that we are not using any more, but it was being used at the time in 15 during regular hours.

You'll notice that the time for the work itself there is very minor differences, one of them being that you'll see the inside staff is for this particular case, which is the collection of the account, is 0.43 hours, and the -- what it ends up doing is you end up having the field staff for .62 of an hour, which is also the same as the travel or the vehicle time down below. You will see 0.62 hours, and there's a $1 charge for -- or, sorry, an 80-cent charge for material.

Now, if we can just remember the .43 hours of inside staff, and this is a collection activity, and also .62, if you now go to 31(b) -- sorry, the table 25, which is on page 55. Yes, thank you. That's the correct one. You will see that there's more inside staff time -- or, sorry, less inside staff time to do just strictly the cut-in of the device rather than the collection cut-in, and the driving time has changed as well, or the staff time, to do the work, as well as the work in the field.

So -- oh, I am sorry, I am looking at the wrong one. That's on a pole. I apologize. So let's go to -- sorry, it's 31(a) I am looking for. I am looking at 31(b). So, sorry, Table 24, I apologize.

Okay. So again, so there was, in the first table, for '18/'19 for the collections, there was the inside staff time, which was .43 of an hour, and on this one it's .29 of an hour, and the breakdown for the field staff straight time in the first table was .62, and on this one now it's .57.

So in our study what we found was that the travel time was less and the work time was less.

MR. QUESNELLE: So it's pure happenstance?

MR. BOLDT: Pardon?

MR. QUESNELLE: It's pure happenstance then.

MR. BOLDT: Yes.

MR. QUESNELLE: Yeah, okay. All right. And you're tracking them different -- what I hadn't appreciated was the calculation of the inside staff's activities, which would be different for the different activities.

MR. BOLDT: Different activities, yes.

MR. QUESNELLE: And the outside staff it's pure happenstance as to what the geography just happened to capture one side versus the other?

MR. BOLDT: Yes.

MR. QUESNELLE: Okay, thank you. Okay. That's all I had for questions. Mr. Vegh, any re-examination?

MR. VEGH: No re-examination, thank you.

MR. QUESNELLE: Okay. Well, thank you very much, thank you very much, panel. And I guess this is the last Hydro One panel. Why don't we take a break, and we will resume with -- Board Staff, you will have your witness up after the break. Thank you. Oh, let's return at ten to 4:00.

--- Recess taken at 3:35 p.m.

--- On resuming at 3:56 p.m.

MR. QUESNELLE: Thank you, please be seated. Mr. Sidlofsky, do you want to introduce your witness?

ONTARIO ENERGY BOARD STAFF - PANEL 1

MR. SIDLOFSKY: Thank you, sir. I am going to be seeking to have Dr. Mark Lowry qualified as an expert in regulatory economics and incentive regulation plans and, particular, total factor productivity.

I will take Dr. Lowry to his CV, but my understanding is that there is no objection to Dr. Lowry being qualified as an expert.

MR. VEGH: That's correct.

MR. QUESNELLE: That's correct? Thank you.

EXAMINATION-IN-CHIEF BY MR. SIDLOFSKY:

MR. SIDLOFSKY: Dr. Lowry, on April 13th of this year, a report bearing your name was filed with the OEB as Exhibit M11, and I'd like you to I'd like to take you to your CV which is ...

MR. QUESNELLE: Mr. Sidlofsky, would you like the witness affirmed?

MR. SIDLOFSKY: Sorry, yes, thank you. Sorry about that.

Mark Lowry, Affirmed

MR. SIDLOFSKY: Thank you, Ms. Anderson. It's still a bit of a challenge to drive the bus and...

So Dr. Lowry, back to the April 13th, 2018, report. That was filed with the OEB as Exhibit M1, and I will take you to your CV which is appended to that report at page 53.

Sir, you are the president of Pacific Economics Research Group LLC?

DR. LOWRY: That's correct.

MR. SIDLOFSKY: And I understand that you have held that position since 2009.

DR. LOWRY: That's right.

MR. SIDLOFSKY: And I will be referring to your firm as PEG. Could you just give me a very brief outline of what PEG's work involves?

DR. LOWRY: Yes. PEG is an economic consulting firm that largely focuses in the area of regulatory economics, and more specifically the economics of energy utility regulation.

We have kind of a specialty in new approaches to regulation, broadly defined as alternative regulation. Here in Canada in particular, performance-based regulation or incentive regulation is very popular, and so we have been active in many proceedings here.

MR. SIDLOFSKY: And, sir, more particularly, can you describe your responsibilities at PEG?

DR. LOWRY: Well, I own the company and so I -- and I manage it, and additionally I do most of our expert witness testimony and serve as principal investigator for most, though not all of our projects.

MR. SIDLOFSKY: And I see that prior to becoming president of PEG, you were a partner at the firm from 1998 to 2009.

DR. LOWRY: That's correct.

MR. SIDLOFSKY: And prior to that, you held a variety of positions, including vice president and senior economist at Christenson Associates, and you were an assistant professor in the department of mineral economics at Pennsylvania State University.

DR. LOWRY: Yes.

MR. SIDLOFSKY: You hold both a B.A. and Ph.D. from the University of Wisconsin, Madison, and your Ph.D. is in applied economics.

DR. LOWRY: That's correct.

MR. SIDLOFSKY: Now, the report filed by OEB staff as Exhibit M1 in this proceeding is titled "IRM design for Hydro One Networks Inc." Did you write that report?

DR. LOWRY: Yes, I did.

MR. SIDLOFSKY: And on May 11, 2018, I expect you're aware that OEB Staff filed a letter in responses to interrogatories filed by parties on your April 13th report. Did you prepare those interrogatory responses?

DR. LOWRY: I wrote most of them, and supervised a few of them.

MR. SIDLOFSKY: Sir, in reference to both your report and the interrogatory report -- the interrogatory responses, are there any corrections you'd like to make to any of those documents?

DR. LOWRY: Yes, there are a few small, but not exactly typographical changes that I think I should correct the record for. The first one appears on page 12 of my report, where it says in the middle of the larger paragraph:

> "PSE found that the addition of reliability and safety variables to the scale index accelerated the TFP trend of Hydro One over a full sample period by a substantial 90 basis points."

Actually it's 50 basis points.

Secondly, on page 34 of the same report, the very last sentence, it says, "the impact" --

MR. SIDLOFSKY: If I can just have you hold on until we can get to that page, thank you.

DR. LOWRY: Of course.

MR. SIDLOFSKY: And, sir, is that page 34 of the report, or page 34 of 67 in the exhibit?

DR. LOWRY: It's the one that's on this page here, but down at the very last sentence. There you go, okay.

So it says the impact on the C factor would be much less if the centre were finished in 2019 or 2022; actually it meant to say 2018 or 2022.

And finally, in response to -- in PEG's or Staff's response to interrogatory 23, there is a table called HONI 23 -- I will wait until you find that. It's the table HONI 23.

Okay. So you will notice that it talks about -- this is about -- well, one of the issues in the proceeding is the appropriate asset price deflators, so I was asked, well, which asset price deflator did you use in this study or that study; particularly Canadian studies were pertinent.

So for the year 2008, there was a misstatement. There was a report prepared by Dr. Kaufmann of PEG for electric productivity, and the Canadian index that was used was the EUCPI, or Electric Utility Construction Price Index.

And those are the only problems that I thought were worth mentioning.

MR. SIDLOFSKY: And, sir, do you adopt the report that's Exhibit M1, the interrogatory responses, and any corrections to those items as your evidence in this proceeding?

DR. LOWRY: Yes, I do.

MR. SIDLOFSKY: And I see that at the end of exhibit M1, you've included a copy of your signed form of acknowledgement of an expert's duty required by the OEB. I take it that you understand the obligations set out in that document?

DR. LOWRY: Yes, I do.

MR. SIDLOFSKY: Okay, thank you, sir. I believe the Board may already have qualified you as an expert in regulatory economics and incentive regulation plans and, in particular, total factor productivity. I would simply ask you to take a few minutes, if you would, and describe your retainer in this matter and perhaps the highlights of your report.

DR. LOWRY: Okay. Well, I was retained by Board Staff to appraise the empirical research undertaken by Power Systems Engineering in support of the company's proposed X factor. And I also took a look at some of the other plan provisions -- provisions of the plan proposed by the company.

And so what I would like to do here, given the brevity of time available, is to touch just on PSE's, Power Systems Engineering's empirical research, and also on the company's proposed C factor.

So starting with the X factor, the PSE research on this topic was led by Steven Fenrick, who is a former employee of PEG, who uses some research methods that are similar to those that we have used in our projects for the Board, so that takes a way a lot of potential areas of disagreement.

His proposed custom industry TFP measure was zero percent, and his stretch factor was 0.45 percent, and they are the same as those that we proposed in this proceeding based on our independent research.

We nonetheless do have some concerns about the methods that he used that I'd like to bring to your attention. Most notably, PSE produced a negative 0.9 percent estimate of the TFP trend of Ontario Power Distributors. This finding was low enough, negative enough, that it attracted the attention in the neighbouring province of Quebec in a recent proceeding on a new IR plan for Hydro-Québec Distribution.

Now, PEG's most recent estimate of the TFP growth of U.S. power distributors over the same period, a similar period. is about positive 0.2, and be it noted that the Régie d'Energie ultimately approved a positive 0.3 percent X factor for Hydro Quebec Distribution.

We believe that PSE's methodology for measuring the Ontario power industry TFP growth has a number of problems, the biggest two of which are that they disregarded a shift to IFRS accounting that most distributors made after 2011, and we feel that they also used an inappropriate output measure, which was different from the one they used when they tried to measure their own productivity.

We believe that the true productivity trend in Ontario is much closer to zero, and note again that the U.S. productivity trend from a recent study for the U.S. government was positive, positive .2.

A second concern we have is about PSE's use of an American utility construction cost index to measure the productivity of Hydro One, but not of the Ontario distributors. There is a need for a new deflator of planned additions in TFP work in Ontario, because the Statistics Canada has stopped publishing the index, I call it the electrical utility construction price index, that we all used to use. But we believe that the use of the American Handy Whitman construction cost index is inappropriate and that the appropriate index should instead be the implicit capital stock deflator for the Canadian utility sector that is calculated by Statistics Canada.

If you use that construction cost index, then Hydro One's TFP growth is considerably slower and in fact is well below that of the norm for Ontario or for the United States, although it should be noted that O&M productivity growth has been fairly brisk in the last few years.

We also have some concerns large and small about the benchmarking work that was undertaken, but we came to roughly the same conclusion, and thus I think it's more important for the Panel to be reminded of what the conclusion was, and that is that the company's cost during the upcoming plan is projected to be about 23 percent above a benchmark, and said benchmark is based on average cost performance, and it's not the notion of any notion of superior cost performance.

So we are already talking about -- in this proceeding about approving revenue requirement that's well above even average cost standards.

Turning to the C factor, I do think that this is the most worrisome provision in the company's proposal. I do recognize that a similar C factor was approved by the Commission for Toronto Hydro.

I should note that I was not involved in that proceeding or in the development of custom IR, although I have been -- played a prominent role in other IR proceedings where supplemental capital revenue is considered, such as three recent proceedings in the province of Alberta.

So let me give you some of my concerns about the C factor and then briefly talk about my proposed remedy. With the C factor, basically between rate cases, Hydro One's revenue for capital is going to be based on their proposed capital cost and basically disconnected from inflation or productivity research.

The revenue cap index essentially applies only to OM&A expenses, and yet it was not designed to apply to OM&A expenses. This is particularly worrisome to consumers, because there is evidence on the record in this proceeding that OM&A productivity growth is more rapid than total factor productivity growth.

Other problems just in general with the C factor approach is that custom C factors can be requested even for small deviations of capital cost from capital revenue. Hydro One is, in my opinion, incentivized to over-forecast its capex needs to create an opportunity for supplemental revenue and just to give it some relief from the pressure for capex containment.

There is also some incentive to bunch capex so that it qualifies for extra supplemental revenue, and there's a perverse incentive to use excessive capex in order to contain the company's OM&A expenses.

Another problem is that the kinds of capex that are addressed by the C factor are the same kinds of capex that are routinely incurred by the companies in any productivity study, and this gives rise to a double-counting concern.

One must also be reminded of the asymmetry of this capital cost treatment. Basically, with a custom IR, a company is allowed to come in and say we need extra money whenever there's a tendency for their capital cost growth to be more rapid than the revenue cap index, but there is no corresponding duty to slow down their revenue when there's a natural tendency for their capital costs to grow more slowly than the revenue cap index.

So for all these reasons, the capex proposals need to be very carefully scrutinized, and to make matters worse, there's this thing called verifiable productivity gains that are needed for the capital in-service variance account that the company proposed. And unfortunately it's very difficult for the commission and for consumers to appraise the prudence of the proposed capex. So regulatory costs ends up being raised considerably.

Now, the Board noted in a recent Toronto Hydro decision that it is desirable to consider how to make custom IR more mechanistic and incentivizing and fair to customers. Thinking of all the options that could be done to remedy this situation, my key recommendation is to make an additional portion of the company's proposed capital cost ineligible for C factoring by some means.

The X factor markdown of Hydro One's proposed capital cost growth that's in their proposal is designed to address concerns that the proposal doesn't reflect achievable productivity gains. Now, the Board disallowed a larger amount of the company's capital costs, 10 percent of proposed capex, in the Toronto Hydro decision, with kind of similar concerns about, how do we know when we are getting good value.

But I have shown here, and in my testimony, that there are additional sound reasons for not giving the utility supplemental capital revenue. For example, in the ACM that is also approved by the Board, there's a 10 percent capex materiality threshold and debt band that is rationalized on different grounds that, for example, it prevents marginal applications and provides some protection against double-counting concerns.

So I conclude by saying that a further decrease in supplemental capital revenue is consistent with past Board decisions as well as my own analysis.

MR. SIDLOFSKY: Thank you, Dr. Lowry.

Mr. Quesnelle, Dr. Lowry is available for cross-examination.

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

Mr. Vegh.

CROSS-EXAMINATION BY MR. VEGH:

MR. VEGH: Thank you, sir. Good afternoon, Dr. Lowry. My name is George Vegh. I am counsel for Hydro One, and I will be asking you some questions this afternoon about your report and your evidence as well. And I will be addressing three points. I think all of them arose in your opening statement.

First, I will be looking -- asking you some questions about the custom industry productivity measure and the productivity stretch factor. Second, I will be asking some questions about the methodology used by PSE in determining the custom industry productivity measure that you described. And then -- as well as the productivity stretch factor. And finally, I will be addressing your commentary on some of the features of Hydro One's custom IR proposal and, in particular, your comments on the C factor.

So turning first to the custom industry productivity measure and the stretch factor, and first just to get some points cleared up on the front, you are aware that PSE's evidence is that the appropriate custom industry productivity factor in this case should be zero, right?

DR. LOWRY: Yes.

MR. VEGH: And at page 3 of your report -- and when I refer to your page numbers, I am going to be referring to your report, not the page numbers of the exhibit, so that's the pages at the bottom of the document.

So at page 3 of your report, you indicate that you agree that this proposal is reasonable?

DR. LOWRY: Yes.

MR. VEGH: And you're also aware that PSE has determined that Hydro One's productivity stretch factor should be 0.45 per cent, correct?

DR. LOWRY: Yes.

MR. VEGH: And again, your evidence is that you prepared your own review and determined that this is also reasonable, correct?

DR. LOWRY: Yes.

MR. VEGH: Okay. I am going to go to page 8, so now that we have that out of the way, the general agreement about the numbers, I do want to address some questions about the productivity research.

And at page 8, there is a section that begins looking at the research, and you note that the issues that do arise in these productivity studies are complicated, right?

DR. LOWRY: Of course.

MR. VEGH: And there are a lot of factors to be considered in the components of those studies?

DR. LOWRY: Yes.

MR. VEGH: And so your concern in this section of the report with respect to these results is not so much the outcome, which you are in agreement with with PSE, but you do have some questions about the methodology that PSE used.

DR. LOWRY: Yes.

MR. VEGH: Now, the Board has made it clear on many occasions that it -- for rate making purposes, it's more concerned about results and outcomes, so the methodology discussion, I think, is somewhat academic. But let's see if we can clarify some of your areas of concern.

And, again, the methodology issues are addressed in pages 8 to 17, and one thing that you mentioned in your opening statement that I would like to discuss with you is your discussion of the asset value price deflator, and that starts at page 8.

And as I understand it, this issue arises because the deflater that had been used in productivity measures was the Statistics Canada's Canadian Electric Utilities Construction Price Index, which I will call the EUCPI.

DR. LOWRY: That's right.
MR. VEGH: And PEG has used this index for researching industry-wide productivity?
DR. LOWRY: We have used it until now.
MR. VEGH: And despite the fact that you used it, you do indicate, I believe at page 9 of your report, that this measure has some draw backs as well.
DR. LOWRY: Yes, it does. It had kind of -- it's kind of odd because the concern about the Handy Whitman index is it grows too rapidly, implausibly fast.
A concern about the EUCPI is that since about 2000, it had grown too slow and as a consequence, could result in an underestimation of productivity growth.
MR. VEGH: Right. So this approach has drawbacks and you mentioned the Handy Whitman approach has drawbacks as well.
DR. LOWRY: Yes.
MR. VEGH: Now Statistics Canada stopped publishing this index, the EUCPI, in 2014, right?
DR. LOWRY: That's right, that's the last year that has a number.
MR. VEGH: Right. So that index had to be replaced?
DR. LOWRY: Yes, it's time to replace it. I mean, you could have patched together a year or two, but now it's getting to be several years and probably time to just replace the whole thing.
MR. VEGH: Right. And as we discussed and as you mentioned in your opening statement and in your report,

that PSE replaced this index with the Handy Whitman Electrical Utility Construction Cost Index, which I will just call HWI, because that's a bit of a mouthful.

DR. LOWRY: Well, they did that for Hydro One, but not for the Ontario industry, making themselves look good but not doing the same treatment for Ontario.

MR. VEGH: But I understand you are concerned about PSE's use of the HWI index to replace the EUCPI index, and that's one of the concerns you identified in your report.

DR. LOWRY: Yes.

MR. VEGH: You mentioned a correction to an interrogatory response, and I'd like to take you to that response, which is HONI interrogatory number 23. And in particular, there's a table attached to that interrogatory and you were asked where -- what indices PEG used.

And as I look down the list, you made one correction, but you still have several -- so 2003 Enbridge Gas Distribution presented to this Board, 2004 Enbridge Gas Distribution, 2007 gas, going down, 2011 OEB IR assessment -- and I am just using the OEB ones here, not the other jurisdictions -- 2015 Toronto Hydro's custom IR application, and then 2016 OPG's IR application.

So PEG has used this index in a number of its studies, right?

DR. LOWRY: Well, we have usually used them in American studies, and are only recently starting to back away from them even in that application.

In the very early days of doing some Canadian productivity research, like research on Enbridge and Union's productivity trends, we did use a Handy Whitman index on the gas side. But then we -- there was a proceeding in which Union Gas was represented by Dr. Melvin Fuss of the University of Toronto and he said, hey, did you ever consider using one of these implicit capital stock deflators that Statistics Canada uses. And ever since then, we have been using that for gas in Canada.

MR. VEGH: Well, I see that, I get your point that some of these are early. But there's a more recent one, the 2016 OPGIR application before this Board used HWI.

DR. LOWRY: Well, that is another proceeding where there was just nothing that we thought was appropriate for purposes of that more narrow category of hydroelectric generation. But yes, it's true, we did use that.

MR. VEGH: Right. So it's been presented to this Board in several cases, presented by PEG. I do understand that you believe that HWI has its drawbacks, but as we have discussed, EUCI has drawbacks, HWI has drawbacks, but the fact that there are drawbacks doesn't really seem to disqualify it from use before a regulator. Wouldn't you agree with that?

DR. LOWRY: Well, I would agree that it wasn't wildly imprudent for Mr. Fenrick to use it. But his having used it, and our having rolled up our sleeves in this proceeding to think, hey, you know, it is time to think what should we use. It seems appropriate to inform the Board of what we found out. We actually spent quite a bit of time on it and came up with a nice little appendix about this matter, and since it does -- our preferred approach does produce a very different result for Hydro One, I think it was appropriate for us to bring this issue to the Board's attention.

MR. VEGH: I am not questioning the appropriateness of bringing this to the Board's attention. I am just making the observation that this an index that PEG uses, and has used before the Board as recently as 2016.

So while you may be of the view that it has some flaws, like all of these other index, it's not fatally flawed. It is something that's been relied upon by this Board, and that PEG as used as well.

DR. LOWRY: It is, as I said, not wildly imprudent for him to have used it. But I would just like to clarify that the one we used in 2016 was not the one for power distribution, which grows so rapidly. It was in fact the one for hydroelectric generation, that he uses in one of his questions to us, to somehow make the point that -- trying to make the point somehow that power distribution construction costs are growing much more rapidly than other assets. In other words, the growth in that hydroelectric generation construction cost index is quite unremarkable.

MR. VEGH: I have followed the back and forth between the two reports, and I would like to just treat it at a higher level because I find, you know, experts can get caught up in the methodology, but as I said, we are more concerned about -- or the Board has been more concerned about results, and so I am just making the point that, you know, when you say it's not wildly imprudent, isn't that a bit of an understatement here in terms of its usability, since the Board has relied upon it and has used it and PEG in fact has relied upon it and has used it?

DR. LOWRY: Well, I think --

MR. VEGH: You are trying to dismiss Mr. Fenrick's report, but on a balanced view, I think you'd have to concede that this is fairly standard index that has been used.

DR. LOWRY: Well, I think it's controversial to use it in a Canadian application when it's not necessary to do so because there are other alternatives. And my extensive discussion of this in response to information requests speaks for itself. I think I made a very good case that the other index works better and produces a very different result for Hydro One, which is really what matters the most in this case.

MR. VEGH: Yes, so let's look at the result for Hydro One, and I am not surprised that your self-evaluation is that you made a very good case for this.

Why don't we turn to page 10, where your report addresses the productivity stretch factor. Page 10 of the report itself. And as you mentioned in your opening statement and as you note in your evidence, PSE's trend estimate for the Ontario distribution sector is 0.91; correct?

DR. LOWRY: Yes.

MR. VEGH: And you make a couple of observations about this. First is that this contains a sizable implicit stretch factor for Hydro One, if this is the right number --

DR. LOWRY: If it's the right number there would be a sizable implicit stretch factor; that's correct.

MR. VEGH: And so just to dumb it down for me, what that means is that for Hydro One to achieve its targets it will have to outperform the sector's productivity by almost 1 percent?

DR. LOWRY: It would.

MR. VEGH: And the second observation you make about this number is that it would be disappointing with respect to what that says about the sector. You say that, I believe, at the bottom of page 10.

DR. LOWRY: It is potentially disappointing, because the Ontario Energy Board is in the business of trying to have incentive regulation that in addition to reducing regulatory costs improves performance. And if it turned out that the performance of the industry was well below a U.S. norm, that would raise concerns. It's potentially disappointing unless it was somehow based on some absolutely required capital spending.

So it is potentially a cause for concern for the Board, in my opinion.

MR. VEGH: Yes, and you identify that as disappointing, but you would also agree if those were the facts and the facts are the facts whether you are disappointed in them or not.

DR. LOWRY: Well, of course. That goes without saying.

MR. VEGH: Okay.

DR. LOWRY: I would like to interject, though, that the Board is not obliged to base Hydro One's X factor in any event on Ontario experience. Hydro One retained Mr. Fenrick to do a statistical benchmarking study that used United States data, and there's no reason having done so that the door is not open to considering American productivity trends as well.

MR. VEGH: But your recommendation is that the appropriate productivity estimate for the Ontario distribution sector is 0.25 percent?

DR. LOWRY: I am sorry?

MR. QUESNELLE: I am not sure if we are waiting for a question or an answer here. You are both studying.

DR. LOWRY: Could you repeat that question?

MR. VEGH: Okay. I understand -- so if you turn to page 17 of your report. I take what you're saying is that minus 0.25 percent is our best current estimate of the cost efficiency trend of Ontario power distributors?

DR. LOWRY: Okay, I think that's different from the question that you asked me. Yes, I did state that, having made some improvements to the methodology, some steps in the right direction, we ended up at about negative 0.25 percent with respect to cost efficiency, which isn't necessarily what you would use for an X factor for Hydro One. But that was not -- that was not portrayed or presented as our final number. In fact, we just feel that there are so many question marks raised by this study about what the actual productivity trend is in Ontario that it's probably best to leave this matter to a possible fifth-generation IR proceeding.

MR. VEGH: Okay, fair enough, because I do understand that you're -- and we will talk about that in a minute, but essentially you are saying that -- you are agreeing with PSE for the purposes of this application, leaving aside fifth-generation and further analysis and further research, which I know you are advocating, for this application the appropriate TFP growth target should be zero?

DR. LOWRY: Yes. In other words, this negative 0.25 would be our best estimate before we stopped working on this knowing that there was quite a bit of work left to do.

MR. VEGH: Fine, I understand that.

So Mr. Fenrick came up with a number that's less than 1, less than -- so less than zero, you came up with a number that's less than zero. And for present purposes we could just proceed on the basis that the number should be zero, given how the Board has used this in the formula in the past.

DR. LOWRY: Well, and my opinion based on results in the United States as well.

MR. VEGH: I understand.

DR. LOWRY: Part of the basis for my own recommendation.

MR. VEGH: Right. And I understand that -- you say a few times in the report that you could take a different approach in a fifth-generation IRM, and -- but there would be further research required to do that, and so even though the approach -- the acceptance of zero in this case, it may not be appropriate in a future fifth-generation IRM proceeding?

DR. LOWRY: It's certainly -- I mean, that's for a future Board to decide, of course.

MR. VEGH: Yes, well, it's also how you proposed to approach this. You say that there are a number of factors to be considered, that there are many issues that have to be addressed, and they are best addressed in a future fifth-generation IRM.

DR. LOWRY: That's correct.

MR. VEGH: And you say that a couple times, and I will just give some page references. I won't take you to every one of them, but you say that at page 14, you say that at page 17, and when you talk about the need for future productivity research in the distribution sector and how that should be updated and the methodology should be improved, you are talking about PSE's research, but you are also talking about PEG's research, aren't you?

DR. LOWRY: Yes, of course. Since we did the fourth-generation productivity study a lot of things have changed. In addition to the fact that we have new evolving views on the best way to measure productivity, there have been quite a few data complications in Ontario that complicate the measurement of productivity and that might even prompt the

Board in the future to go back to looking at U.S. productivity trends or both U.S. and Ontario trends because Ontario data have become more problematic since that study was done.

MR. VEGH: Right. So in that future fifth-generation IRM research and process that the Board will carry out and that you're recommending these issues be addressed here, I assume that the PSE approach could be included in that review as an alternative. You could criticize it and recommend that the Board not adopt it, but it certainly wouldn't be qualified from being considered in that kind of review.

DR. LOWRY: I don't know what you mean exactly by being disqualified. I mean, if that study with its obvious flaws was included, the Board could either say we reject that approach, or they could just choose a number based on another study.

The Board is certainly not above ruling on methodological issues; they have done so several times when it comes to productivity, which is one of the reasons that we have tried to put a short list of methodological issues before them in this proceeding.

MR. VEGH: All I am getting is that you're making -- PEG and PSE come to the basic bottom line -- or share the basic bottom-line conclusion. You have methodological differences as you have described, and PSE has addressed them as well, and those will all go into the mix of a future proceeding.

And I am just saying that that's really the place where the Board has to make that sort of determination as to which methodology is the superior one, not in this case.

DR. LOWRY: That's right.

MR. VEGH: Okay. So I'd like to ask some questions about the benchmarking research conducted by PSE, that again you've described. And in particular, I am looking at page 19 of the report where -- and I believe you've described this. Again you and PSE have different methodologies, different theories perhaps, but the bottom line is PSE concludes that Hydro One's costs were about 22.2 percent above the model's predictions, and PSE therefore proposed a stretch factor of 0.45 percent for the term, right?

DR. LOWRY: Yes.

MR. VEGH: And I understand your conclusions, again with some methodical differences, but your models ultimately conclude that Hydro One's costs are about 22.4 percent above the benchmark during the term.

DR. LOWRY: Yes. I would like to say about that, though, that we were not authorized by the Board to do our own full independent studies. We changed some of the things about the PSE study for the better, and it could be that the -- we would have had a more different result if we had just done an independent study. But we were not asked to do that.

MR. VEGH: Right. So your evidence in this case is that the 0.45 percent stretch factor is reasonable?

DR. LOWRY: Based on the evidence, yes.

MR. VEGH: Yes, well, that's good. So let's turn to some of the other design issues that you mentioned in your report, and that you addressed in your opening statement.

One of the issues you spent some time on in the Report, though I didn't hear you -- well, that you spent some time on in the report is with respect to the revenue cap index, and your suggestion that the revenue cap index have contain an escalator for growth.

DR. LOWRY: Yes.

MR. VEGH: And I -- and how you put it, as I understand it, is that an escalator for growth in the revenue cap index is preferable to addressing new investment through a C factor.

DR. LOWRY: Yes. Well, the revenue cap indices are used in a number of jurisdictions around North America and revenue caps generally are used, with or without the indices, more commonly outside of Ontario than they are inside. And those formulas usually do contain a growth escalator, and the growth escalator that is used is specifically the number of customers served.

For example, that is the formula -- has been the formula for Alberta gas distributors and was just approved for Hydro Quebec distribution as well.

I'm very concerned about the C factor and so when I saw that there was no growth factor in this formula and that the company sort of said, well, don't worry that's covered by C factor -- in other words, if the revenue cap index isn't growing rapidly enough, the C factor will take care of it.

That just sets off some red lights in my mind that there's something to be said for their doing it the proper way and then having less of a C factor. Basically, any way that you can reduce the role of supplemental capital revenue is desirable if it can be done, of course, responsibly.

MR. VEGH: So that's the connection I was looking for, because you effectively say if you had a growth escalator, you could replace the C factor as a way to fund new capital.

DR. LOWRY: No, it would simply reduce the C factor.

MR. VEGH: Fine; reduce the C factor, that's fair. And you believe reducing the C factor in the way you propose and replacing it with a growth factor is a preferred way?

DR. LOWRY: Well, I think adding a growth factor, one consequence of which is a lower C factor, is probably preferable.

MR. VEGH: And in terms of the impact of that approach, at page 32 of your report you indicate what the impact would be of your proposal of having a growth factor and using that.

So I want to look at the consequence of this, and this is addressed at page 32 of your report, first full paragraph, the last sentence, there's a lot of discussion about the numbers and growth factors and you say: "In either case OM&A ...," if you added this growth factor, "OM&A revenue would grow by this additional amount and the C factor would fall, but allowed capital revenue would likely be unaffected on balance". Right?

DR. LOWRY: That's right, in this case.

MR. VEGH: Yes.

DR. LOWRY: In this particular application.

MR. VEGH: I'm sorry?

DR. LOWRY: In this particular application.

MR. VEGH: Yes, well, that's where we are. And at page 33, at the very bottom of the page, you make the same point. You say the OM&A revenue -- applying the growth factor you are describing,

> "The OM&A revenue requirement would rise a little bit more rapidly, but the C factor would fall and capital revenue would be unaffected."

DR. LOWRY: That's right.

MR. VEGH: So as I understand it, your criticism with respect to the C factor, in lieu of a growth factor at least, is not so much about impacts on customers and impacts on rates, but it's really a criticism of the capital factor as such, using a capital factor.

DR. LOWRY: Well, you certainly want to use any supplemental capital revenue very sparingly. So here was a case where it was being needlessly large and so I feel that -- and then besides, we have to think about repeated applications of this. Now, this Toronto Hydro approach has now been used again, and many others could come in asking for something similar. So getting it straight, there could be a time eventually when by dint of fine-tuning and adjustments, that there would be no grounds for a C factor at all. That may not be the case in this case, but it could be in another case.

So is there's something to be said for starting to get the whole process right, with a goal of reducing the need for a C factor, or any other supplemental capital revenue.

MR. VEGH: I do understand your views towards reforming approaches approved and taken by the Board. But again, we are looking at this case and as I understand what you are saying at pages 32 and 33, the concern is not so much with the revenue impact of using the C factor as proposed as opposed to a growth factor, but a more principled criticism of having supplemental capital through a C factor.

DR. LOWRY: Well, there are a number of reservations to providing supplemental capital revenue there C factor, or any other means. And in this particular case, as I say, this is a needless -- the C factor is needlessly large, so why not -- why wasn't this -- I am not saying that there shouldn't be a C factor or supplemental capital revenue in any case. I am not totally opposed to it, but it really is something that you want to keep to a minimum.

MR. VEGH: But again I am back at these two observations. I don't really see a lower revenue impact by your proposal; is that right? Is that fair?

DR. LOWRY: Not on capital, not just this one, no, you

are isolating just this one part of my proposal. But --
MR. VEGH: We will get to the other part, but I am --
DR. LOWRY: No, right, so --
MR. VEGH: -- trying to understand the relationship between the growth factor --
DR. LOWRY: This would not affect capital revenue in this application.
MR. VEGH: And in fact, it would have OM&A revenue go up a little bit.
DR. LOWRY: It would have OM&A revenue go up a little bit.
MR. VEGH: So OM&A revenue goes up; capital revenue is basically unaffected.
DR. LOWRY: Correct.
MR. VEGH: And as I understand your criticism -- and I know you have several of them, but bigger picture -- the capital factor, seems you're concerned with it, it's ultimately a cost-of-service approach, and so you are critical of cost of service as a method of regulation; is that fair?
DR. LOWRY: Well, I am not sure that would be my only criticism, but --
MR. VEGH: I didn't say it was your only --
DR. LOWRY: -- many -- many of my criticisms could kind of be grouped under that heading, yes.
MR. VEGH: Okay. And you mentioned the Toronto Hydro case, and I am sorry for -- I am going to ask you some questions of your concerns with respect to the more cost-

of-service type approach to a C factor, and you mentioned the Toronto Hydro case. And I am going to take you back earlier -- to an earlier part of your report where you discuss the Toronto Hydro decision.

So at page 3 of your report, you -- when you are providing your overview description of what's being proposed by Hydro One, you say:

> "The custom IR plan proposed by Hydro One is in several respects uncontroversial. The design is similar to that of the custom IR that the Board approved for Toronto Hydro."

And that, of course, included a C factor approach that the Board approved; right?

DR. LOWRY: Yes.

MR. VEGH: And PEG gave evidence in the Toronto Hydro case on behalf of the Board, right?

DR. LOWRY: Yes.

MR. VEGH: And we did ask you about that, and there is an interrogatory I'd like to take you to, which is Interrogatory No. 3 by -- filed by Hydro One. Perhaps we can just scroll down and get the full question and answer, because as you indicated PEG did give evidence in that case on behalf of Board Staff, so -- representing a public-interest perspective, and PEG did not take the anti-C factor approach that you seem to be taking here; is that fair?

DR. LOWRY: Yes, that's true.

MR. VEGH: And as I understand your response to the interrogatory, you seemed to say that the major difference is that in the Toronto Hydro case PEG put forward Lawrence Kaufmann, while in this case you are coming forward; right?

DR. LOWRY: Yes, and let's detail some of the differences. For one thing, I am the president of the company, and I am very active in PVR proceedings across Canada. I play a prominent role in every single populous province of Canada, and in every single one of these cases this matter of supplemental capital revenue has been coming up, and particularly -- it was a particularly hotly debated issue in recent Alberta PVR proceedings. Their first-generation PVR, for example, had a capital tracker, and they were very unhappy with it, and so they made some big changes in the rate-making treatment of that in their second generation plan.

So I like to think that I have a lot of experience on this issue, and it's been accumulating as recently as the Quebec proceeding, where, by the way, the Régie de l'Energie has approved a much more restrictive policy about supplemental capital revenue than there is here in Ontario.

MR. VEGH: I understand your views of your contribution to this sector and to the field generally, but Mr. Kaufmann was put forward by PEG.

DR. LOWRY: Um-hmm.

MR. VEGH: He provided evidence to the Board of what was in the public interest as best he could, and Mr. Kaufmann was also an expert.

DR. LOWRY: Yes, he certainly is.

MR. VEGH: And I assume he was qualified by this Board to give expert evidence, and you would consider him able to support reasonable positions and criticize unreasonable positions?

DR. LOWRY: Based on his knowledge set. But as I say, I am -- I have been involved in many more proceedings where supplemental capital revenue is an issue, and I have become sensitized to the issue, because basically what's happened in -- if you wanted to put the history of -- the recent history of Canadian regulation into a sentence is that commissions have taken an index -- an interest in index-based regulation and the larger utilities have raised heaven and earth to evade the capital spending restrictions.

So I am sensitized to that. I don't think that when Dr. Kaufmann was doing this he was aware, and some of the things hadn't really even happened yet. Some of the developments in Alberta, for example, hadn't really happened yet.

MR. VEGH: Well, he gave his best evidence, and my only point about this is that he is an expert, and isn't it fair to say that reasonable people can disagree on this?

DR. LOWRY: Certainly.

MR. VEGH: And then the Board released its Toronto Hydro decision and released filing guidelines after that decision and provided direction to say that there's been a lot of experimentation and different approaches to IRM, and put forward the Toronto Hydro position effectively as a model that utilities can rely upon when providing subsequent IRM applications.

DR. LOWRY: Well, I believe that the Board has been pretty clear that there is no template for custom IR.

MR. VEGH: Right.

DR. LOWRY: It's supposed to be company-specific, it's supposed to evolve over time, and I don't know that all of the ideas of evolution are to come from the utilities, as opposed to staff consultants or consumer advocates. I think it's an evolving matter. And if the Toronto Hydro approach needs fine-tuning, boy, this is the best proceeding to do it in, because not only is it early on in the process before other people can do the same thing, but it's one of the largest utilities in the province, and --

MR. VEGH: One of your criticisms of the C factor, as I understand it, is that it does end up using a lot of regulatory resources.

DR. LOWRY: The C factor.

MR. VEGH: Using the C factor.

DR. LOWRY: Yes, it does.

MR. VEGH: And that's for the Board and for the parties.

DR. LOWRY: Yes.

MR. VEGH: And you think that's inefficient from a regulatory perspective?

DR. LOWRY: Well, if it's a necessary cost then that's reality, but the issue is, is it necessary or are there ways, as the Board said in the Toronto Hydro decision, to move further in the direction of mechanization and incentivization of custom IR if possible. I think it is possible.

MR. VEGH: And so you're aware that the Board does have a policy of following past decisions?

DR. LOWRY: Well, I mean, I think it should be attentive to past decisions, but obviously regulation in Ontario evolves and will continue to evolve. So it should be one consideration for the Board. But they are always evolving the way they do things. That's one of the things that makes them one of the world leaders in PBRs, that they are always thinking of better ways to do things.

MR. VEGH: But there is also some value in regulatory predictability, isn't there?

DR. LOWRY: That's true with respect to a plan. Once approved, they shouldn't change the plan in the middle unless it's absolutely necessary because of acute over-earning or under-earning, but I don't think that this is anywhere close to being set in stone enough that that should be a consideration in this proceeding. I mean -- and besides, what I have proposed is not that radical adjustment to custom IR.

MR. VEGH: And applicants and parties spend a lot of time, investing a lot of time, investing resources, in preparing applications to bring to the Board, and obviously the Board spends a lot of time, and the parties, and a lot of resources are put into evaluating those applications, and do you think it's reasonable for applicants and other parties to expect that the Board will be consistent in their decisions and not relitigate policy decisions in every case?

DR. LOWRY: Again, the Board obviously evolves its policies over time. And it can and should, and it should also be mindful of good -- you know, when they did something good they should stick with it, and when there's a way to make it better they should consider that.

MR. VEGH: And if the Board's inconsistent so that --

DR. LOWRY: You are talking here about custom IR. You are not talking about, you know, the fourth generation IR, for example. Changing that in the middle of things would -- that would be more of an eyebrow raiser, but this is custom IR, so let's customize.

MR. VEGH: Yes, but I don't know if you get in the weeds of preparing an application in the way that we mortals do.

But when you look at a past application and the Board adopting filing guidelines with an expectation of what's expected by the parties, the approach from a regulatory efficiency perspective is that the Board is also providing guidance to applicants on how they should bring forward their applications, and not just change their decisions because they got a different consultant in this case than they got in the last case.

Isn't that fair? Isn't that a regulatory efficiency as well? And isn't this lack of certainty, lack of direction, lack of clarity changing the rules every time?

Isn't that a regulatory inefficiency?

DR. LOWRY: A search for a better system of regulation is, in my opinion --

MR. VEGH: No, it's the luck of the draw for the consult...

MR. QUESNELLE: Mr. Vegh, you have posed the question a couple of times. Let Dr. Lowry answer.

MR. VEGH: I apologize.

DR. LOWRY: I think that there is a benefit to the Board to listen to different, well-qualified consultants occasionally. And if I come into this proceeding and have some independent thoughts, I think it would be irresponsible of me not to bring them to the Board's attention.

MR. VEGH: If an applicant then prepares the application and it depends on the luck of the draw as to which consultant PEG happens to put forward, doesn't that bring a randomness to the regulatory process?

DR. LOWRY: Well, I think it be it noted that PEG also evolves. Just like in our productivity research, when we get a good idea, we stick with it until a better idea comes along. That's why we changed to Dr. Fuss's (ph) general idea for an asset price deflator.

You will notice in this proceeding that I mentioned something about average hourly earnings instead of average weekly earnings. That was actually an idea that Hydro Quebec Distribution proposed and I said, you know, that's better than what we do, so I recommended it.

So I think that there is a -- you will find with PEG that they don't go crazy back and forth with their recommendations, that their idea, their notions about best practices evolve over time.

MR. VEGH: Why don't we leave that point because today you happen to show up from PEG, and you do identify a number of factors that you are concerned about with the C factor. And as I mentioned more generally, you raised some concerns about its cost of service -- its basis in cost of service. I appreciate that's not your only concern, but that is an umbrella which you express a number of concerns.

You do appreciate that the stretch factor in this case does apply to capital as well as to OM&A?

DR. LOWRY: Yes.

MR. VEGH: And that there is a variance account, so there is no incentive to over-invest in capital?

DR. LOWRY: Well, I think that the variance account -- I think what you -- I couldn't agree with your statement as you've put it. The variance account somewhat discourages exaggerated capex forecasts, because you can't play a game like they have in Britain, where they say we need this much capex and it turns out, you know what, we didn't need it after all, thanks for the extra money.

So I think that the true-up is more about exaggerated capex forecasts.

MR. VEGH: And during the plan term, there's no incentive to over-invest, because there's no recovery of any capital costs that are outside of what's put forward.

DR. LOWRY: Well, there's no incentive to invest more than the approved budget.

MR. VEGH: That's right. I'd like to understand some of your related criticisms, again based on the components of C factor that resemble cost of service, and first is one that you identified at page 34 of your report as well as in the opening statement today, which is at the bottom of page 35, where you talk about the incentive to bunch expenditures to increase revenues.

And your last sentence, maybe I -- maybe this is more clear now after your correction, but I did not understand your point that the impact of the C factor would be much less if the centre -- you are talking about an operations centre -- were finished initially you said in 2019 or 2022, and you've changed that to 2018.

How is Hydro One's revenue impacted if it makes an investment in 2018 or 2022 versus the term of the plan?

DR. LOWRY: Well, in 2018, it becomes part of the base revenue requirement that the revenue cap index applies to, which could -- would considerably reduce the need for supplemental revenue.

Meanwhile, if you did it in 2022, you would get the least amount of supplemental revenue because it's right before the rate case.

MR. VEGH: Okay. I think I understand that better now, but this is again a theoretical concern. You haven't looked at the operations centre and investigated the merits of the timing of that operations centre and whether it was practical to put it in 2018, or practical to extend it out to 2022. This is more of a theoretical concern, more than on the merits of the actual proposal?

DR. LOWRY: That's correct. I haven't reviewed the -- I mean, I would be surprised that something like that has to be done in any one year as opposed -- the Board could almost encourage projects like that that don't have an obvious completion date to be done at times when it would simplify their regulatory process.

I am not advocating that. But like I say, it wouldn't be that crazy to advocate that.

MR. VEGH: Right. But instead what we've done -- what's happened in this case is that there's been a lot of evidence put forward on the a pacing and priorities of capital investment and, you know, the Board will determine that pacing and priority on its merits.

And that's also a reasonable approach, isn't it, as opposed to just working on the assumption that they're either front-end loading or back end-loading?

DR. LOWRY: You're right. Of course, that is a very time consuming process and a lot of guesswork on the part of the Board in knowing what's right and what's wrong in a matter like that.

It's always -- it's understandable therefore that there be a search for more mechanized and incentive-rich approaches to providing the supplemental revenue.

MR. VEGH: I want to get through some -- I want to go down your list of criticisms of the C factor, and I believe those are at page 37 of your report.

Let me put it this way. To be more fair, you say there are some amendments that you think merit consideration. And there's a bullet, four bullet points, and I'd like to go through them with you.

So the first is that the C factor should be subject to a materiality threshold or dead zone. And further --

DR. LOWRY: Or may I just clarify? Or more generally a further disallowance than what has been discussed or proposed, like they did in the Toronto Hydro proceeding. They just disallowed 10 percent of capex at the end.

MR. VEGH: Yes, and I think that's a good way to put it. It's almost like an automatic disallowance, isn't it?

DR. LOWRY: Well, it doesn't have to be as seemingly arbitrary as the 10 percent in the Toronto Hydro case. But some way of saying no, you are not going to get every dollar of your shortfall is a way to go that has more precedent in Ontario, because it's already been done several times here.

MR. VEGH: Well, you suggest -- you do suggest 10 percent, don't you?

DR. LOWRY: I don't know that I said 10 percent specifically, no, because it kind of depends what you're applying the materiality threshold to. Is it -- I mean, the threshold and dead band system for the advanced capital module is focussed on the capex, whereas you have this C factor proposal. So it could be based on a C factor, a further -- some sort of C factor disallowance, or it could just be a percentage of capex disallowed. So there's really two or three different ways.

MR. VEGH: I guess my -- the 10 percent figure came from page 38 of your report, where you seem to be endorsing what the Board -- how you interpreted what the Board did, which was to disallow 10 percent of Toronto Hydro's proposed capex. So my understanding from reading that -- from participating in that -- well, reading that decision, is that the Board made that decision on the merits, as opposed to just an arbitrary 10 percent reduction.

DR. LOWRY: Well, I don't know how they would come up with a round number like 10 percent based on complex calculations that they didn't share with the company. I think that they were dissatisfied with the quality of evidence, they were uncertain what was right, and so they wanted to come up with a reasonable knock-down of the proposal. 10 percent sounded fair to them.

MR. VEGH: And so when we talk about dissatisfaction with the quality of the evidence and not accepting the proposal, that sounds like a prudence review. And in cost-of-service models, that's basically what the Board does, right? They look at prudence, and if they are looking at the prudence of a capital investment plan, isn't it arbitrary to just disallow 10 percent or 5 percent or 1 percent or whatever number you happen to come up with? Because you are not proposing that this be based on any prudence review. You are just saying, Board, you should just disallow 10 percent.

DR. LOWRY: Well, I --

MR. VEGH: Even if the prudence of these investments were demonstrated to you, just disallow it.

DR. LOWRY: Well, again, that is actually the Board's policy in the advance capital module and the incremental capital model. 10 percent materiality threshold irrespective of your -- the quality of your evidence; is that not true?

MR. VEGH: And then -- but you do appreciate that IRM is available for utilities where the ACM or the ICM is inappropriate, so the Board is not just imposing a 10 percent dead zone but expecting a rebasing, companies come forward, they put evidence forward, the Board takes it seriously, and doesn't -- I mean, we could have saved a lot of time, right? This case was filed over a year ago. If the rule were, we just cut 10 percent regardless of what you put forward, that could have -- I am just saying that's a pretty arbitrary approach to be determining a cost-of-service rebasing. Wouldn't you agree with that?

DR. LOWRY: Well, again, a modest disallowance -- there is already precedent for a modest disallowance based on -- you know, the rationale for the Board of doing that, recollect it, was partly about concern about double-counting, but it was mostly just about discouraging frivolous applications, and on those grounds alone they said 10 percent, and that's part of my argument, that, hey, there's many more reasons than that to have a disallowance, so many solid grounds for a disallowance, so provided that it's modest, I don't think it's necess -- I don't -- I don't know that it's reckless. Not to say that I specifically endorse the 10 percent that they chose in the Toronto Hydro case, just that this Board has done this on a number of occasions.

MR. VEGH: Well, I think the ACM approach is a little more principled than what you are suggesting, but it applies to discrete projects, as opposed to, you know, a C factor on a going-forward basis, but I will just leave that there, because I want to explore one other part of what you say of this disallowance, this automatic disallowance of whatever percentage strikes you.

And at the top of page 38, the last sentence of the first paragraph, you talk about these dead-zone approaches. You refer to the 10 percent disallowance or ACM, et cetera, and you say:

"Any of these approaches can make customers whole for the addition of a growth escalator to Hydro One's RCI."

And so this would be a rate mitigation measure? That's how you are characterizing this here?

DR. LOWRY: Well, I -- remember, I am not here to solely represent the customer interest or certainly not the utility interest, but the general public interest, and I have noticed that I wasn't -- I didn't hesitate to propose one thing that would actually help the company and give it more revenue. Well, since apparently the company didn't need that extra revenue you could use that as one basis to

-- for a further disallowance of their capex.

MR. VEGH: Yeah, that's not exactly how you put it, to be fair. You say "any of these dead-zone approaches", and I will just call it a disallowance, "can make customers whole for the addition of a growth escalator." Now, Hydro One is not proposing a growth escalator, so there is no reason to mitigate, right?

DR. LOWRY: With respect to that I am just saying if you did have a growth escalator you could feel even more comfortable with a further disallowance, because you have given them something they didn't even ask for.

MR. VEGH: Well, under Hydro One's proposal, which does not include a growth escalator, this mitigation measure is just not required; is it?

DR. LOWRY: Well, that particular mitigation measure would not, but that doesn't mean that there isn't a need for a further haircut on the company's supplemental capital revenue.

MR. VEGH: Though you did identify what you could consider to be these disallowances -- I won't editorialize by calling them arbitrary, but they do seem to be a mitigation measure for something that you are proposing that's not in the application.

DR. LOWRY: It's -- I am just saying that if you were to give the supplemental capital -- the supplemental growth escalator, you would -- it would be all the easier for the Board to approve this further trimming of supplemental capital revenue.

MR. VEGH: Right, but since that's -- that's entirely hypothetical, because Hydro One is not proposing it and therefore does not require the mitigation. This is your proposal that would increase the revenues, and therefore you are saying you could mitigate that increase by cutting capital 10 percent. Well, if that -- if that's not part of the process and this cutting of capital 10 percent doesn't mitigate that, it's just a cut.

DR. LOWRY: A cut, but not a cut without reason. I have enumerated seven reasons.

MR. VEGH: Well, let's keep going down your reasons. The second bullet point on page 37 you talk about, the X factor could be raised. I don't want to spend too much time on this, because you have agreed in this case that the X factor proposed by PSE is reasonable, and we have discussed the -- we have discussed the X factor, the challenges with changing this and how it might be addressed in a future proceeding, so I just want to highlight that that's one factor, but that's the X factor which is already kind of settled as reasonable.

So the third bullet point in your list here is a proposal to scale back eligibility for a C factor, for example, by saying that the last year of the planned term is ineligible for a C factor; right?

DR. LOWRY: Yes.

MR. VEGH: Now, that's somewhat similar to the first -- to the first bullet point, isn't it, and that is just an arbitrary disallowance in advance of what you're proposing regardless of the prudence?

DR. LOWRY: Well, I don't know how arbitrary it is. The reason that that could make sense is that it is only one year before the rate case. So you're not going to -- you are not going to have as much attrition from not getting compensated for it in that year.

MR. VEGH: Sorry, I didn't mean to interrupt.

DR. LOWRY: No, that's fine.

MR. VEGH: All right. So you -- but as you indicate, it's the Board determining that you are not going to be compensated, and so that's not based on any kind of prudence review, just the year in which the investment happens to be made.

DR. LOWRY: That's right. Another example of that would be, don't fund growth-related capex. I have discussed that in other proceedings too, but I have just used this as an example here.

MR. VEGH: Okay. And I think we know where we stand on that.

And then the final point you raise is that the C factor could be calculated using a different productivity trend growth of capital, but then you conclude in your last sentence for bullet point 4:

> "There is no conclusive research available to the OEB in this proceeding on OM&A and capital productivity trends of power distributors."

So there's no empirical basis for this proposal; right?

DR. LOWRY: Well, there is an empirical basis, but the question is, is there enough evidence for the Board to make a decision: Let's reprise that evidence. The firmest evidence is that a recent study that I did for Lawrence Berkley Lab found OM&A productivity trend of US power distributors to be considerably -- well, 20 or 30 basis points more rapid than total productivity, and even more compared to capital productivity.

However, Power Systems Engineering was not permitted to review that study, and so you can't -- you can only put so much weight on that since it wasn't properly vetted.

And then the other number we have is the number of OM&A productivity from this -- these quick corrections of Mr. Fenrick's work, and I have not tendered that work as being any sort of definitive estimate of the productivity trend in Ontario. It did, however, show brisk OM&A productivity growth.

But in my opinion, this is not enough evidence. The evidence is firmer in the gas case that the Board is also considering right now, because we had a very nice productivity study of US gas distributors that showed an even bigger gap between OM&A and capital productivity. So in that proceeding, I did say, you know, you ought to seriously consider this separate regulation of the two because as soon as the company is asking for a C factor, they are already asking for separate regulation of the two. So there's already been a schism and why not follow through on the logic of it.

MR. VEGH: But there's no evidence in this case that you can rely upon in support of -- the suggestion in bullet point 4 here.

DR. LOWRY: Insufficient evidence.

MR. VEGH: There's insufficient evidence?

DR. LOWRY: The quality of the evidence is probably not enough for the Board to render a decision on that in this case, that's right.

MR. VEGH: In this case, thank you. Well, that's the case that we're in.

Thank you, panel, I have no further questions.

MR. QUESNELLE: Thank you, Mr. Vegh. Mr. Sidlofsky, any re-examination?

MR. SIDLOFSKY: No, thank you, sir.

PROCEDURAL MATTERS:

MR. QUESNELLE: Thank you very much, Dr. Lowry. Can we just have a few minutes to discuss the schedule of arguments?

Mr. Vegh, do you have a proposal from the applicant?

MR. VEGH: I have discussed this with Board counsel and I understand that there have been discussions with other parties as well. So the idea was on the assumption that the hearing will -- the oral hearing will finish tomorrow, which it's finished today.

I believe that the schedule -- and Mr. Sidlofsky or Mr. Davies you can correct me if I am wrong, because I may be out of date here -- but the plan is that Hydro One will file its submissions July 13th-in-chief. The intervenors and Board Staff will then have three weeks to respond, which would be August 3rd. And then Hydro One would be given four weeks to respond to that, I believe, which would be September 7th.

MR. QUESNELLE: I know this is a large case, Mr. Vegh, but four weeks is a little longer than the norm. Is there something special about the ...

MR. VEGH: Well, there is the Labour Day weekend in the middle of that.

MR. QUESNELLE: True enough.

MR. VEGH: As you can appreciate, throughout July and August, it does end up being a difficult time with having availability.

MR. QUESNELLE: Yes, point taken.

MR. SIDLOFSKY: Sir, if I could just jump in? We did have conversation with Mr. Nettleton earlier in the -- I believe it was earlier this week, and there were some different dates that were proposed. I wouldn't say we have a plan at this point for this, that the parties have come to any sort of agreement on a plan. But I believe that Mr. Nettleton's schedule, his suggested schedule, had started with July 23rd for argument-in-chief.

I am looking to Mr. Rubenstein to confirm that, but I believe that was where the schedule would have started. Then August, I believe it was 13th for Staff and intervenors' submissions and Hydro One's reply would have been September 10th. So I am --

MR. QUESNELLE: So is this being laid before the panel to pick A and B?

MR. SIDLOFSKY: Well, it wasn't intended to be a menu, sir, but ...

MR. VEGH: Sorry for providing that information -- as I said, it may have been out of date. I had an earlier conversation with Board Staff, but I hadn't consulted the parties. But Mr. Sidlofsky's schedule seem a reasonable one.

MR. SIDLOFSKY: Sorry, it's just not my schedule. It was originally Mr. Nettleton's.

MR. RUBENSTEIN: Mr. Nettleton seemed quite adamant that Hydro One could not get their argument-in-chief before the 20th or 23rd. That's kind of where the dates fell, so that may change. I don't -- I'll look to Mr. Vegh.

MR. QUESNELLE: Well, as much as the Board is under a lot of pressure to get decisions out faster, and no matter how you like at it, when you look at the start date of a file date, and when a decision goes out, all the things that happened in the middle get lost.

So I take September 10th as being the close of submissions when we are finishing up here today in June, I know that we are talking long weekends and summer months, but it seems a little unusual.

Can we leave it to the parties to negotiate something a little tighter than that, and then report back to Board Staff and we will issue something by way of procedural order.

MR. VEGH: Thank you, sir, that's reasonable and I apologize for the confusion.

MR. QUESNELLE: It's quite all right, Mr. Vegh. With that, we will adjourn and we will -- again, we will leave it to the negotiations and we will get a procedural order out as soon as possible. Thank you very much.

--- Whereupon the hearing adjourned at 5:24 p.m.