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THE ONTARIO ENERGY BOARD

Generic Hearing on Uniform Transmission Rates-Related Issues and the Export Transmission Service Rate

Technical Conference held by videoconference
from 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Friday, July 29, 2022
commencing at 9:30 a.m.

TECHNICAL CONFERENCE

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BILL HARPER	Vulnerable Energy Consumers Coalition (VECC)

I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

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

Friday, July 29, 2022

--- On commencing at 9:30 a.m.

MR. SIDLOFSKY: It is 9:30. Why don't we get started.

Good morning. Welcome to day 2 of the technical conference to deal with clarifications of interrogatories related to the export transmission rate -- export transmission service rate component of the uniform transmission rate proceeding.

My name is James Sidlofsky. I am with the Ontario Energy Board.

I won't repeat appearances from yesterday, but if there is anyone on the line today who wants to identify themselves and make an appearance, and enter an appearance, that would be great. If you could please do that now I would appreciate it.

MR. VELLONE: Mr. Sidlofsky, I have an associate of mine that's joined me today, Colin Boyle, just for the purposes of putting the evidence up on the screen and facilitating questioning.

MR. SIDLOFSKY: Okay. That's great. Thanks. Thanks, Mr. Vellone. Good morning, Mr. Boyle.

MR. BOYLE: Good morning.

MR. SIDLOFSKY: Not hearing from anyone else, we will move on to you, Mr. Vellone. This is your panel this morning. So if you could introduce them, that would be great.

MR. VELLONE: Thank you very much, Mr. Sidlofsky. With us today we have Travis Lusney and Brady Yauch, both from Power Advisory. Their CVs are attached to the evidence that they filed, so I am not going to spend too much time introducing them and instead open it up for questioning.

ASSOCIATION OF POWER PRODUCERS OF ONTARIO - PANEL 5

Travis Lusney

Brady Yauch

MR. SIDLOFSKY: Okay. And with that, we have VECC first up. Mr. Harper.

EXAMINATION BY MR. HARPER:

MR. HARPER: All right then. Again, my name is Bill Harper. I am a consultant on behalf of VECC, and maybe if I can start off with some good news. I went through my notes last night and reflected somewhat on what was said yesterday, and with any luck I think I will be considerably under my time estimate, which means we will move through it more quickly today than originally anticipated.

With that, could we turn up Power Advisory response to LPMA 2A.

MR. BOYLE: Let me just share my screen here. LPMA 2.

MR. HARPER: 2. And it is part A. That's great.

Now, I just want to look at the third sentence there. Here in the third sentence you state:

> "There does appear to be any market failure that a regulatory process must address."

Now, would I be correct in saying there is a "not" missing from that sentence, such that it should read:

> "There does not appear to be any market failure

that a regulatory process must address."

MR. YAUCH: That's correct, yes, it should say there does not appear to be any market failure.

MR. HARPER: Okay. I just wanted to make that clear for the record. Thank you.

Now if we can maybe turn to Power Advisory's responses to VECC 5.1 and VECC 5.2.

MR. BOYLE: 5.1 and 5.2?

MR. HARPER: Yes. Now, based on your responses to these two questions, I take it Power Advisory is not recommending or advocating any specific ETS rate; is that correct?

MR. YAUCH: That's correct.

MR. LUSNEY: That's correct.

MR. YAUCH: Yes, we were asked to look at a change from, you know, 185 up or 185 down, so we looked at the impact of the change, but we didn't settle on what is the correct rate.

MR. HARPER: But based on your response to this IR and other IRs as well, would I be correct to conclude that for reasons of system efficiency and system-wide benefits you would favour a lower, as opposed to higher, ETS rate?

MR. YAUCH: The evidence shows a lower rate has potential to provide system-wide benefits, both financial and from an operational point of view for Ontario, but we are not advocating the Board settle on one number in particular.

MR. HARPER: All right. And also, I guess, and also within these responses, I think, given that context, I think you also recognize that there are a number of other considerations of putting fairness and transparency that need to be balanced eventually by the regulator in making any decision on the ETS rate?

MR. YAUCH: That's right. Rate-setting, as you know, is a very complex endeavour, and regulators can include a number of variables when they go to set rates, and so we say straight-up economic efficiency may not have to be the only consideration the OEB would consider, but -- so it opens it up to a variety of other rates and the options.

MR. HARPER: Great. Maybe we could turn now to your response to Energy Probe 2A. Yeah, I just want to -- yeah, and here you were asked for Power Advisory's view as to what was meant by cost causality principles, and you responded:

> "At a high level, cost causation means that someone who causes a cost to be incurred is required to pay for it, essentially that any party that imposes a system-wide cost is allocated that cost."

Then you go on after that.

In terms of cost allocation principles, are you aware of regulators adopting an approach that considers not only parties who cause the cost but also considers parties that benefit from those costs?

MR. YAUCH: We didn't do a detailed review of the jurisdictions on all of the rates and options that someone might consider when setting rates. That was just our view of what cost causation is, but agreed that regulators could take a variety of different approaches in doing it.

MR. HARPER: And would you view that some regulators have a particular approach that includes, when considering cost allocation, considering those who benefit from the costs that have been incurred?

MR. YAUCH: I mean, I don't think we will agree to what other regulators have done without pointing us to a particular situation. I mean, there are many different rates set in many different jurisdictions, so I'm assuming somewhere out there possibly, but, you know, we can't agree to that.

MR. HARPER: Well, maybe Mr. Lusney would like to comment on that.

MR. LUSNEY: I think linking back to the earlier response to your previous question, that, you know, there are other considerations that have come in with rate decisions from a regulatory panel, such as the OEB. There is going to be principles as you go forward, but they're not hard set rules, and you have to make decisions based on all facts, but what we're kind of describing here in this answer is related to cost causation, and we believe, you know, it's costs incurred, should be required to pay for it.

MR. HARPER: I guess the reason I was struggling with this was, I guess in response to VECC 10.3 you filed the evidence that Mr. Lusney had provided in an IESO proceeding a number of years ago, and I really didn't want to go to it, but within that proceeding, Mr. Lusney's evidence made reference to the concept of system benefits being a principle that could be used in cost allocation, and actually made reference to a couple of regulators, FERC and California, that had employed that principle.

Maybe without going to the evidence, can you generally agree that those topics were covered within the evidence of that point, that you provided in the attachment?

MR. LUSNEY: I think in any decision within a jurisdiction it's important to recognize the uniqueness in that jurisdiction and what is relatable to that jurisdiction when doing other alternative jurisdictional reviews and relationships.

So in the IESO 2013 tariff where we filed evidence on behalf of the UCA, we were looking at a unique Alberta construct, which is a no-congestion system, and trying to understand the rate-making processes that were being driven there both from reliability principles, but also policy drivers.

And so that was trying to relate directly to the Alberta construct and that things, and then that is kind of back to the point of, there are other considerations that have to be unique within the regulatory framework for that jurisdiction.

MR. HARPER: Okay. That's fine. Can we go to your response to Energy Probe 3C. I guess, and maybe this goes to the same topic, because here you were asked whether you were opposed to a user pay principle, which to some extent is a benefit paid principle, because users benefit from the system, and you say, no, but then you list a number of specific caveats that you think should be taken into account if you actually apply that principle.

I guess what I see is the clear distinction, specifically when I come to points B and C in your response, between incorporating those elements specifically in the cost allocation model itself, as opposed to considering them in conjunction with the results of a cost allocation model.

And I guess within the context of your caveat there, were you proposing that they should be specifically incorporated into the cost allocation model? Or at the end of the day they should be considered -- it is important to have them considered in conjunction with the results of the cost allocation model?

MR. LUSNEY: Our view, it is considered. I mean, these are aspects that need to be weighed as part of any decision-making process.

And there are core principles that you can go down to that might help you divide and come to conclusions. But at the end of the day, I mean this is a complex cost allocation requirement and build-out and you are trying to at least make sense of it from a principles point of view, but it is not hard rules.

MR. HARPER: Fine. Thank you very much. Can we go to -- I guess it is back to LPMA 2A.

Here you state at the last -- it is the last part of that first paragraph there, where you state:

"Export customers more than cover the cost of operating and maintaining the inter-ties, which is the only infrastructure explicitly used by export market participants."

Now, and you specifically use the word "use", so I guess I would ask don't market participants also use Hydro One's new network, in terms of getting that power they've purchased to the inter-ties?

MR. LUSNEY: So one back to our cost causation, you know, what is the driver to build out the system? What is important to recognize is just from a core principles point of view, generation does not pay to use the transmission system.

It is primarily a customer-based driver. And you build out the system to meet loads and loads are the ultimate funder of the system.

Use of the system also differs between different -- what you could call classes. It is not clearly defined whether it is a firm delivery or an interruptible delivery as, you know, roughly defined by ourselves.

So I think it is important to recognize, you know, some of this comes from principles and how you allocate costs and determine build-out of the system. And others come from, okay, we have a certain set up. What is an appropriate sharing of those costs, if it is appropriate in one way or another, and when is the system being used and what is it being used for and what are the added benefits.

I think that is where our evidence is trying to come from is recognize it is not a narrow aspect. It is a much more broader impact to customers and this is the impact of a lower ETS.

MR. HARPER: I understand. I was just focussing on specifically on what seemed to be the specific statement here which was that they only use the inter-ties. I take it you would acknowledge that they used more than just the inter-ties, but because of issues like interruptible, et cetera, maybe their use isn't the same as it would be for a load customer.

MR. LUSNEY: I think what is unique and should be recognized in the Ontario system is you don't have firm transmission rights through the Ontario system.

So if you are an exporter, you don't know exactly what generation output you are moving out, and it could be a generator at a tie which you are not using the network, or it could be a generator buried deep inside, and that is really not -- there is no capability of assigning that in one way.

MR. HARPER: I guess that kind of applies to any load in the province.

MR. LUSNEY: Yes.

MR. HARPER: Yes, okay, fine. I think that is clear. Can we go to Power Advisory's response to Energy Probe 6B?

Here you cite the export opportunity service XOS, and the demand opportunity service DOS, under the Alberta electric system operator's transmission tariff as examples of where economic opportunity was used by utilities separately that were accrued by regulators.

There wasn't a lot of detail here, so I was just curious. What is the economic opportunity in this particular case that was being used in setting the export tariff?

MR. LUSNEY: So again back to different jurisdictions, so different unique circumstances, and the evolution of tariff designs is an organic thing, not a full reset; you build on it.

In the Alberta aspect and for a system that is designed to have no congestion under normal circumstances -- or more accurately put, a hundred percent of energy must flow when normal operating circumstances exist in the transmission system.

So the economic opportunity in that in this case is when there is, for lack of a better term, available capacity on the system that can be used by opportunistic users, whether it is export or demand, that would not be economic under a firm transmission set up.

So for demand, this would be demand transmission service, DTS, verses demand opportunity service that would only use it when there is slack capacity on the system. And there is a whole rate design and cost allocation principles that sit behind them.

MR. HARPER: I am familiar with that concept. I think BCU used a similar concept for a while as well, actually.

Can we turn now to the CRA study that was filed as part of the Hydro One IESO submission, specifically attachment C, where it starts at page 23 of 24.

MR. BOYLE: Sorry, which one was that?

MR. HARPER: The joint Hydro One IESO submission at the start of this process effectively, and the CRA study which I believe is attachment 2 to that report. And as part of the CRA study, there is an attachment C which is found at page 23 of 24 of the CRA report. I know there’s so many attachments here, it gets a bit confusing in terms of how to refer to them.

Actually, right. You are right there, right there. I want to ask are you familiar at all with this attachment or have you gone over it at all?

MR. YAUCH: We reviewed it at a high level, but we didn't take a detailed review of it.

MR. HARPER: If you can't answer this, that's fine. But what I was struggling with was the fact when I read this attachment, in particular the three paragraphs, it suggested to me that the AESO export tariffs were based on -- essentially on a cost allocation study.

I was trying to square this with your statement that economic opportunity is used in setting the rates.

Maybe if I understand Mr. Lusney's response -- and I don't want to put words in your mouth, but maybe as a basic first step cost allocation is used and that is how the basic rates are set. But then these opportunity rates are set sort of as a -- to address unique circumstances.

Would that be a fair -- I am just trying to square your comments and what I see here.

MR. LUSNEY: Part of our comments in responses -- and maybe we should have clarified it as the ongoing current IESO tariff discussion that is happening in Alberta, which is contemplating changes on how these preferred rate designs using the a -- preferred rate design and then the propagated impacts down on XOS and modernized DOS and for certain consultants' avocation for a new storage opportunity service and similar.

So it is a mixture. But I think going back to part of this is also the unique circumstance of what Alberta is, which is a very unique market, being energy-only design and a no-congested transmission system.

MR. HARPER: Okay, fine. Thank you. Like I said, I was just trying to square those two points in my mind.

Can we turn up your response to VECC 17.1? Here we asked about the derivation of the average export line in figure 13 of your evidence.

You stated that the average exports in every hour were predefined by predefined HOEP ranges.

To understand that a bit more given that statement, could we maybe go to figure 13 in your evidence. So that would be in the Power Advisory evidence itself, figure 13.

Now, just looking at this figure, I noticed that -- I am going to approximate the numbers, but I noticed that a HOEP value of zero dollars there seems to be an associated export megawatt value of just over 2500 megawatts per hour.

I don't need any precision on the number. I was just wondering can you tell me what the predefined HOEP range was that was used to calculate that roughly 2500 megawatts?

I'm sorry, Brady, I don't thick your mic is on.

MR. YAUCH: Sorry about that. Zero dollars and below.

MR. HARPER: And similarly, I notice that at the five dollar per megawatt, there seems to be an associated export value of roughly 2300 megawatts per hour. Again, what HOEP range did you use there?

MR. YAUCH: Zero to five.

MR. HARPER: Zero to five. Okay, fine, thank you very much.

Now, in your analysis, you have used the change in HOEP as a proxy for the change in ETS rates to estimate the impact of a change in the ETS rate on both export volumes and on the ICP. Is that correct?

MR. YAUCH: That's correct.

MR. HARPER: Would it be fair to say that these relationships you have used between HOEP and exports and HOEP and ICP are really a key part of your analysis?

MR. YAUCH: They form the basis of it, yes.

MR. HARPER: Now, in your evidence, you indicate that an increase in ETS rate of 4.69 per megawatt-hour would reduce export volumes by 17 terawatt-hours. And that is on page 38; you don't have to turn it up.

But maybe if we can go to VECC 19.1, then. Here we asked you to provide a schedule setting out the calculation of the 17 terawatt-hours and the data used, and you provided the data used in an Excel attachment.

But really, in terms of the explanation, it was really in my mind a high-level explanation of how the calculation was done. And I must admit, while I think I understand how it was done, I am not precisely certain. What I would like to do, if you would be patient with me, is walk through to some extent my understanding of what the -- how the calculation was done, and you can -- and if I am right then or if I am pretty close we're all happy. If I'm wrong we'll have to take this somewhere.

MR. YAUCH: Okay.

MR. HARPER: And I think, you know, your high-level attachment is provided -- your high-level explanation, excuse me, and maybe we want to go there -- is provide an attachment A to your -- to the Power Advisory IR responses. I mean, that is really the last two pages in the IR response document that you filed.

Now, if we gown to step 6, because I think this is really where you describe what you have done. And in scenario A you describe how you calculated the impact of the $4.69 per megawatt-hour increase in ETS, and as I understand it, what you did was you calculated the average exports per hour over a range of HOEP intervals, where the first interval was minus ten cents to $4.69, and as I understand it correctly, the next interval would have been 4.70 to sum value. Maybe you can just let me know what the upper end of the second range was.

MR. YAUCH: You add 4.69 to 4.69. I think it is 9 --

MR. HARPER: Right. And then similarly, you had equally, you know, wide intervals of HOEP. You -- progressively going up after that, and you calculated the average exports per hour in each of those intervals. That would be what you have done; is that correct?

MR. YAUCH: That's correct.

MR. HARPER: Yes. And then really, in order to get the change, what you did is, let's say if you wanted to understand what the change was in HOEP in that first interval, minus ten cents to 4.69, you would have looked at the next interval up and compared the average exports there with the average exports in that minus ten cents to 4.69 interval, and that change would have been what you had assumed for that first interval was the change in average exports that would take place if you increased the ETS with $4.69.

MR. YAUCH: That's right. The only -- it's not an average, so you look at total exports --

MR. HARPER: Right. But as we say, that is the change in the average, and then to get the total you multiple that average by the number of hours in that interval covered.

MR. YAUCH: No. For the numbers in the report that underpin, let's call it the $42 million net increase in cost, it is the sum. So there is a total --

MR. HARPER: Right. Right. Sum. For each of those intervals you calculate the total number of -- the total change in export volumes in that interval by the average change multiplied by the number of hours, then you'd sum that up over all of the intervals in order to get the total for the whole thing, right?

MR. YAUCH: It's not -- there's no -- like, you don't average in the analysis, right? So let's say there is 10 terawatt-hours of exports in zero to 4.69, and then there is 7 terawatt-hours in 4.69 to 9.38. Well, there is a 3 terawatt-hour difference. So it's just the sum -- the difference between those two, the total amount of exports that flow to different buckets.

MR. HARPER: Right. But those intervals are going to have different number of hours. Each interval is not -- is not -- each interval is not going to cover the same number of hours, correct?

MR. YAUCH: Based on prices, not hours.

MR. HARPER: Right. No. I know. Because it is based on prices, I thought what you did was you calculated the average export per -- average exports per hour in each interval, compared that change in average, and then multiplied that by the number of hours in the interval to get the total change.

MR. YAUCH: No. We took -- if you're looking at just the exports, there is a total amount of exports in a certain price bucket. That is called the first -- zero to 4.69. Let's say it is 10 terawatt-hours.

MR. HARPER: Right.

MR. YAUCH: Then the next price bucket there is a certain number of total terawatt-hours of exports, and the idea is to say you're using HOEP as a proxy to see how export volumes respond to different price levels.

MR. HARPER: Right. But let's say that first bucket of terawatt-hours, you know, because of the range of HOEP it covered, covered 1,000 hours -- covered 1,000 hours of the total period and the second bucket only covered 500 hours. Don't you have to somehow take that difference into account when you are doing your calculation?

MR. YAUCH: I don't think so, because you're trying to show that export volumes will increase when prices are lower. Like, it's intuitively sensible, because as prices are lower you're going to have more hours or more total volumes of exports, and because Ontario is a low-priced environment over the last four years, particularly when this analysis was done, you're going to likely have more hours that are lower price than higher price.

MR. HARPER: No, I understand the principle of that. It was actually the mechanics of the calculation that I was struggling with, and rather than going through this I think I understand what you have done. To be quite honest, I don't agree with it, but that is another -- that is another problem. We will take that up a little bit later on sort of thing.

Now, can we go to VECC 19.2. And here we asked how Power Advisory's calculation of the decrease in export volumes due to an increase in the ETS rates accounted for the fact that an increase in the ETS rate will not impact export flows in hours where the ICP is greater than the ETS rate increase. And this is something that we discussed with the IESO panel yesterday.

In your response you basically refer to that attachment we just have been looking at and said this answers your question, and I am not too sure if it does, and I was wondering if you could provide me a specific answer to that question in VECC 19.2. And if you want to think about it, take it as an undertaking, that is fine by me as well.

MR. LUSNEY: Give us -- if it's okay, can we have a minute for a breakout room to chat?

MR. HARPER: Sure.

MR. LUSNEY: We're -- just for everyone, we're in the same room together, so we will just turn our cameras off. We won't need -- Ashley, we won't need an actual breakout room, thank you.

[Witness panel confers]

MR. YAUCH: Thanks for that. I mean, our response is really the same. You know, we walked through the methodology. We looked at export volumes by price buckets using HOEP increases as a change to the ETS and then look at the increase in -- increase or decrease in export volumes, as well as increase or decrease in congestion rents.

So it is the same exact process that we described, that we just walked through five minutes ago.

MR. HARPER: Yeah, no, I understand the process that you went through. I was trying to understand where the process specifically -- how the process specifically addressed the situation that I set out in that question. And --

MR. LUSNEY: Can I --

MR. HARPER: And I guess what you are telling me, it does, and that is the end of the answer, that's fine, I will take the answer you are giving me.

MR. LUSNEY: I think -- go ahead, John.

MR. VELLONE: Bill, I don't understand the premise of the question, and maybe you can explain that to me.

MR. HARPER: Well --

MR. VELLONE: Exporters pay ICP and ETS --

MR. HARPER: Right.

MR. VELLONE: -- so if ETS just -- if ICP just happens to be higher than ETS, that doesn't matter.

MR. HARPER: No. But the discussion we had with the IESO yesterday, and we went through the things, was specifically if the ICP happens to be higher than the contemplated increase in the ETS rate, then what will happen is there will be a one-to-one trade-off between the ICP and the ETS rate, but there will be no impact on export volumes. That was the -- that was -- that was part of the IESO's evidence and part of their attachment to the original submission. That was what I went over with them yesterday.

And so I was asking, there appear to be situations where an increase in HOEP or, you know, or an increase in the ETS rate would not change the export volumes, because the ICP at the start of the process was higher than the anticipated increase in the ETS rate.

And I just wanted to know, how does the methodology take into account or capture that particular circumstance?

MR. YAUCH: I can answer this. The analysis doesn't do an hour to hour look at every single hour which has happened.

So there could be times in which that happens. But there could be times in which the ICP and export volumes both decrease. And we walked you through a very high level example in response to one of your questions, I believe, that both could happen at the same time.

So I know the IESO said it is just a straight one for one, but it is not clear that every single hour is going to be straight one for one. And you wouldn't be able to answer that unless you look at the actual bids of every single export in every single hour.

MR. HARPER: That goes to your point that I think you acknowledged a number of times maybe -- I won't say complain, but you said that, you know, the data you had was not as quite as much as would have been ideal in doing your analysis.

MR. YAUCH: That's correct. And I think this is a good time to sort of lay that out that, you know, when you look at the data available that the IESO publishes compared to other wholesale markets, it is severely lacking, frankly, in our opinion. If you had the proper data to look at export bids, you could look back on a historical basis and see exactly what would have happened if you lowered or increased the export bids to a certain amount.

So the lack of data does limit the accuracy of the study in our opinion. And as you noted, we were very clear about that throughout.

MR. HARPER: No, that's fair. Maybe we can just quickly go back to step 6 in your methodology. So that would begin going back to attachment A at the very end of the IR responses in step 6.

Here you also set out a scenario B, which is really where the ETS would decrease from $1.85 down to zero.

Would I be correct to say that the methodology you used was exactly the same, except the intervals were now $1.85 applied going through the process?

MR. YAUCH: Yes, it's just the reverse.

MR. HARPER: Right, it is the reverse and you changed the width the of the intervals. That's fine, I think I understand that.

At a high level, would you agree that export volumes are influenced by more than just the value of the HOEP, that they're also influenced by limits on the inter-ties that could change, and influenced by the temperature of the day and capability of an inter-tie on a particular day?

MR. LUSNEY: As we noted in our evidence, the reason why export volumes occur are multiples, and can be driven by a whole bunch of different aspects. And similar to questions from other intervenors, you know, the reason why something trades is not always a real time decision; it can be days ahead, months ahead.

MR. HARPER: Right. So also influenced not by that, but also -- not only by what is going on in Ontario, but also by the prices in the neighbouring jurisdictions. I think that is something you pointed out in your own evidence as well.

MR. LUSNEY: That's correct. That is one of the aspects.

MR. HARPER: Those prices in neighbouring jurisdictions, they vary hourly as well.

MR. LUSNEY: Right. And while it is just -- we have used neighbouring as part of our analysis, or looked at it, I mean you can make the argument that you need to look at the next neighbour and next neighbour, and all the way down to Florida.

MR. HARPER: Right.

MR. YAUCH: Bill, if I could just add. In our report, there is a graph where we look at prices in zone A, which is right across the river from Quebec in New York, and the exports flow into zone A even when the price spread doesn't appear obvious, right, and it looks like you are losing money. That is why we're pointing out trades can happen for a variety of reasons.

So we don't know what every single decision-making process is happening for every single trade. But there could be times -- it is not just pure price spread in real time that is driving it.

MR. HARPER: Okay. So maybe I will put this to you. So what I have been struggling with is that -- so why it is reasonable to assume that the change in export volumes that would occur in a given hour if the HOEP or ETS were changed by 4.69 in that particular hour, can be estimated by looking at export volumes in a different hour when the HOEP is 4.69 higher, but when system conditions are going to be totally different.

I guess that is -- there is a fundamental difference between changing the ETS in a particular hour in that hour and looking at it, which I guess is what you would do if you knew the bids in every hour, as opposed to looking at a different hour where the HOEP was 4.69 different in looking at the export volumes there, but also you acknowledged a whole bunch of other things have also changed in that hour as well, whether it be neighbouring prices, capability on the export ties, temperatures, that would also impact the export volumes.

So to some extent, that seems to me that sort of muddies the analysis, if I can put it that way. I don't know whether you would like to comment on that or not.

MR. LUSNEY: I think one of the core -- our objective and why we were retained was to provide help to the panel in making the decision, and provide an analysis on what an impact of a higher ETS or lower ETS.

As we state throughout our evidence, you know, this is a very complex, convoluted, real time impacted, month ahead impacted.

So what we've attempted to do, and we believe we have achieved in our analysis, is providing a clear and transparent and simplistic at times analysis to provide guidance to the panel, so that they can come to their own appropriate decision when looking at our evidence and other information that's been filed by all other participants in this proceeding.

So we recognize there is a lot more complexity, but back to the part of the issue, without more firm data points to allow us to dig deeper, there is a risk that the analysis becomes less, much less helpful.

So we wanted to be grounded in a foundation that is fruitful for the panel to consider.

MR. HARPER: Okay, fine, that's fair. Can we turn up VECC 17.2? Here we asked you for an analysis of the relationship between HOEP and exports, and you declined to provide it. That's fine. I am not going to pursue that.

I would just like to confirm whether you have actually done any statistical analysis to determine whether there is a statistically significant relationship between the HOEP values in your analysis and the export volumes in your analysis.

MR. YAUCH: Our methodology -- you know, as we weighed out as the methodology is we use actual data to look at the actual changes in export volumes, congestion rents, based on changes in HOEP. So that was how the methodology was used.

MR. HARPER: But you didn't do any statistical analysis to see whether it was noise or whether it was a -- whether there was -- whether there was a statistically significant relationship between the two?

MR. YAUCH: No. We just used the HOEP value as a change in the ETS as a proxy for the change in the ETS.

MR. HARPER: That's fine. Similarly, can we turn to 18.3 and 18.4, your responses to VECC.

I guess maybe before I get into this, I understand your analysis of how congestion rents change when you change the ETS rate really follows -- you really followed exactly the same approach as you did with the export volumes. Except this time, instead of looking at export volumes within each of those price buckets, you looked at ICP revenues within each of those buckets. Would that be a fair comment?

MR. YAUCH: That's right. I think this term statistically significant keeps on getting thrown out, and the point was to look at historical actuals.

Like you didn't need to do a statistical regression analysis because you could look at exactly what happened with the change in HOEP, and the HOEP is the driving factor in exports. So as HOEP changes, exports change and it is very clear that they change quite significantly based on HOEP, because that is the only thing that is driving them in a --

MR. HARPER: Maybe I can stop you -- sorry if I interrupted you. If I could stop you there.

MR. YAUCH: That's okay.

MR. HARPER: Your comment it's clear that they change. I think I would ask you to qualify that term "significantly", because again that has connotations as to what you mean by significantly.

Maybe say materially, that might be a fair comment to make.

MR. YAUCH: We can settle on materially.

MR. HARPER: Okay, that's fine. Again, you just use the data that was there. You didn't do any more analysis than what you presented in your report?

MR. YAUCH: No. And to another comment, like so we do a lot of price forecasts. We have a market simulation model very similar to what the IESO uses. Underpinning those models are vast assumptions.

For the benefit of the panel and other parties, we try to say what's the easiest and most transparent way to look at this, and that is how we settle on this methodology. We do have a lot experience with market simulation models, but we wanted to strip out all of the problems that come with the assumptions. And the fighting we would have over assumptions -- which is fair fighting, but it would be there and we think it would distract the issue.

MR. HARPER: Okay. That's fine. I think with that, I think I can actually skip a couple of my next questions and maybe move on.

Can we go to VECC 21.3? Here we asked for details supporting the 17.9 million for increases to curtailment costs due to -- curtailment costs of wind due to a 4.69 increase in ETS.

Your response was that it would require a significant amount of work. I was wondering if you could explain to me why would it require a significant amount of work, when you must have done the calculation to actually put your report together in the first place.

MR. YAUCH: We didn't know if you were asking to provide the whole models and all of that, but I can tell you -- explain to you how we do it, and maybe this will answer your question.

So you take the change in export volumes when you change the ETS, and the zero to 4.69, and that export volume, we're assuming that would get curtailed for wind, and then we cut it in half, because we don't know -- you know, we don't know which would actually be curtailed, because we have no access to hourly data, bids and offers, so we assume, we halved it, would be curtailed, and it's just the market -- the lost market revenue, which, half of it is 17.9 million.

MR. HARPER: Right. And if I understand your -- I mean, you didn't do that over the full range of HOEP prices. As I understand your sort of explanation, you did it by looking more specifically at the change between the minus ten cents to 4.69 interval and the interval up, and the interval went up from that, and it was just a change -- it was just that interval that you looked at.

MR. YAUCH: That's right. That's right. We assumed wind wouldn't be curtailed beyond that.

MR. HARPER: Right. Okay, fine. I think your explanation is -- I was going to walk through a bit of my understanding, but I think your explanation matches my understanding exactly, so I think we are good to go on that.

I'm just trying to think. I think I can probably skip the next one. Yes.

Can we go to VECC 27.1. And just to confirm, similarly here, this was for the decrease in ETS rates from the $1.85 to zero. And again -- again, you would have just done the reverse and done the reverse analysis?

MR. YAUCH: That's right, yes.

MR. HARPER: And in this case, since you did the reverse analysis and your analysis started with that first interval, minus ten cents to 4.69, what two intervals did you compare, you know, what was -- I was trying to figure out what you would have compared to come up with the 5.8 terawatt-hours in this case.

MR. YAUCH: Sorry. Zero to 1.85. So it seems bigger -- or quite large, because there's a smaller range. It is because exports are very price-sensitive in that zero to $1.85 range.

MR. HARPER: And it was zero to $1.85 and then compared that range with the $1.85 to 3.70? Would that be --

MR. YAUCH: Yeah, exactly.

MR. HARPER: Okay, fine. Thank you. Thank you very much.

Now, can we go to your response to Staff 20C. And this deals with the curtailment of hydro -- hydroelectric facilities. Here staff asked you about the basis for the $14.40 you used as the cost of hydro curtailment, and you stated:

"It is based on the assumed highest marginal cost of hydroelectric facilities."

And I guess -- so what -- I guess what was your source or basis for the 14 -- maybe just to start off, what was your source or basis for the 14.44?

MR. YAUCH: Yes, so --

MR. HARPER: 14.40, I apologize.

MR. YAUCH: 14.40. So in OPG's last rate application they had to file evidence related to SBG and hydro. And in that evidence they lay out 14.40. So we used that -- you can calculate marginal cost using gross revenue charge and go through how it is calculated. The province tells you how it is charged --

MR. HARPER: Right.

MR. YAUCH: -- but we use that because it's publicly available.

MR. HARPER: And when you say it is the highest, I mean, that suggests there is a range of values.

MR. YAUCH: There is, yeah. So the gross revenue charge will change on the size of your facility, essentially the property taxes you pay to the province. So it will -- there is lower and higher. So smaller facilities have lower marginal costs than higher facilities, so if you look at Beck and Saunders, the two big ones, they tend to have the higher marginal costs, according to our reading of it.

MR. HARPER: Excuse me. I am having some tree work done. I'm going to go close my window, hoping that will cut down on the background noise. I will be back in just a second.

MR. YAUCH: Okay.

MR. HARPER: Sorry, I am getting some clean-up done from that 24th of May windstorm. This is the only day the arborist would come, and I wasn't going to say no.

MR. YAUCH: You and Hydro One.

[Laughter]

MR. HARPER: Right. Okay. Let me get myself back on track. So -- and I'm sorry, Brady, I will just have to read the transcript, because I didn't catch that last response, but I will go back and read it.

MR. YAUCH: I can say it again. I mean --

MR. HARPER: Okay. Thank you.

MR. YAUCH: -- the 14.40, there is a range of marginal costs, right? We assume 14.40 is the highest because the way you calculate your gross revenue charge changes on the size -- the output of your facility, so bigger facilities will have a higher marginal cost. That is a publicly available number. We use that because it is publicly available. Marginal costs will change even at the same plant, over the same hour and the same -- you know, their price quantity pair offers will change quite a bit, so we just use access publicly available.

MR. HARPER: Okay. And staying with Staff 20, the response to 20A states:

"Power Advisory analyzed exports when prices were between 13 to $14 per megawatt-hour and 17 to $19 per megawatt-hour, and the decline in exports in those ranges was used as a proxy for potential for curtailment."

However, maybe we can turn back to your evidence, page 41 of your evidence. And here you state:

"Power Advisory assumes that a decrease in exports when HOEP increases from 15 to 20 dollars."

You seem to use a different range here. I was just wondering if maybe you could clarify what ranges or values you used in the analysis, because there seemed to be some confusion here.

MR. YAUCH: Yeah, it used -- it is a 13 to 15, the one in the IR response, and we just -- it was for simplicity purposes we did 15 to 20, so -- but the exact range is described in the IR.

MR. HARPER: Okay. And listen, I couldn't find anywhere in the evidence what the dollar value -- what the assumed reduction in -- you know, what assumed change in curtailment was because of this increase, like the terawatt-hour value associated with it. Maybe you can just let me know what that was.

MR. YAUCH: Yes. I can probably provide it now, but we can also do an undertaking.

MR. HARPER: Whichever is easiest. I just, I couldn't find that number anywhere in the evidence.

MR. YAUCH: After the break we can probably just provide you the answer so we don't have to do the undertaking if you are okay with that.

MR. HARPER: I am perfectly fine with that.

MR. YAUCH: Okay.

MR. HARPER: And actually, to be quite honest with you, this is my last question, so that if I am not still here after the break if somebody else is questioning and you can just give the answer, that would be great.

MR. YAUCH: That would be great, okay.

MR. HARPER: With that, I am all done. Thank you very much for your patience.

MR. YAUCH: Thanks.

MR. SIDLOFSKY: Mr. Harper, thanks very much. The morning break was scheduled for after your questions, but you have been very economical, so I think what I would like to do is move on to Mr. Rubenstein for Schools, and then I expect we will probably take the break after that.

So if the panel could just remember that they do owe an answer, I am not going to mark anything as an undertaking at this point, but if you find you can't come up with an answer during the break, then we will take an undertaking from you.

MR. YAUCH: Okay.

EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Good morning. I am wondering if we can start at Power Advisory response to SEC number 1. So in this interrogatory we asked you to confirm that Power Advisory's quantitative analysis is based on 2018 to 2021 supply and demand conditions and market data. And if confirmed, please confirm that insofar as the conditions change in the future, Power Advisory's analysis will be impacted.

In your response you say:

"Power Advisory confirms the first question."

Which I take to be that the quantitative analysis is between the 2018 to 2021 supply and demand conditions and market data.

With respect -- but then you also go on to say:

"Power Advisory does not confirm the second question."

And then you provide some comments.

I just want to make sure I understand what you are saying. Do I take it it is your view that if the supply and demand in market conditions are different in the future as compared to 2018 to 2021, you're saying that they will not impact your analysis? It seems to be obvious. I take it you may not know how it will impact your analysis, but there will be an impact. Correct?

MR. YAUCH: If supply conditions change in the future, as they will, both in Ontario and in neighbouring jurisdictions, there will be some impact.

The overall value that exports provide and the way in which they provide it that we laid out in our evidence, we don't think that will change. But the numbers will certainly -- will certainly change, because the numbers will inherently be different.

MR. RUBENSTEIN: But you would agree with me that the value could either be -- depending on what the conditions are, they could be -- exports could become more valuable or they could become less valuable?

MR. YAUCH: The future is inherently uncertain, and it depends what happens in Ontario and what happens in neighbouring jurisdictions.

MR. RUBENSTEIN: So I take it that is a yes to my question?

MR. YAUCH: I mean, things will change, yes.

MR. RUBENSTEIN: And so then the value of exports can -- may increase or may decrease, depending on the situation.

MR. YAUCH: That's correct.

MR. RUBENSTEIN: Okay, thanks. Can we now go to Power Advisory's response to Staff 11B?

Maybe I am going to ask a question and you may have sort of addressed this in some of your questions from Mr. Harper, but it will help me better understand it.

So the question that you were asked -- the preamble to the question was from OEB Staff, and they were referencing a reference in your report that says a cost benefit analysis should be assessed when determining cost allocation to secondary users of the transmission system.

Then in part B, they asked you:

"Please explain what Power Advisory considers to be an appropriate cost-benefit analysis methodology to determine cost allocation to the secondary users of the transmission system."

In your response, you reference the current opportunity service modernization underway in Alberta is a good example of reassessing the appropriate tariff of exports.

Can you discuss what exactly you are referencing? What exactly is going on in Alberta?

MR. LUSNEY: So as I mentioned earlier in responses to VECC, the Alberta electricity system operator is proposing an overhaul of their whole tariff design, and changing to a different -- what they're calling a preferred rate design. And then the impact of that is they're also looking to modernize and update their opportunity services and the underpinnings to that.

So in coming to all of those changes, that system operator is putting forward, well, what other cost changes and what are the potential benefits, and how is the system being used differently and supply mixes and customers, and everything like that.

So it is just recognizing that when you do major overhauls like that, you can't be too narrowly focussed on just the costs. You have to look at the total system.

So I think to maybe expand on that a little bit, I mean, Ontario's system, there is certain uniquenesses to it. The supply-side is a fixed -- primarily a fixed cost system. We have almost all supply contracted or rate regulated. And you need to understand not just the real time market prices that is reflected by HOEP, but the other costs to customers related to global adjustment uplifts, along with the delivery costs that will change transmission, distribution. You want to try to be as holistic as you can when making adjustments.

MR. RUBENSTEIN: And I think this was part of that process is part of what you were talking about with Mr. Harper. My understanding -- there's a proceeding going on in respect to this, I believe, the procedural difference in Ontario, and the ASO has to get their approval by their regulator, correct?

MR. LUSNEY: That is correct. So any changes to the tariff design must be filed with the Alberta Utilities Commission, AUC, for approval of which multiple stakeholders and intervenors have intervened. And for disclosure, myself and my consulting resources are an expert in that proceeding related to the modernized demand opportunity service and the preferred rate design on behalf of Energy Storage Canada.

MR. RUBENSTEIN: Just at a high level, my understanding is it's quite a contentious proceeding. There are a lot of different views and the ASO's proposed approach is being highly contested by certain parties. Correct?

MR. LUSNEY: I don't believe I would be stretching when I say yes, it is highly contentious and there is a significant volume of alternative evidence being brought forward to argue a multitude of changes that are being considered by the ASO, or being proposed by the ASO.

MR. RUBENSTEIN: Okay. Can I ask you to go to Power Advisory's response to Staff 14? So Staff asked you in part A:

"Please provide Power Advisory's comments on the expected impacts of market renewal program on congestion rents received by the market, TR auction revenue, TR payments to right holders and avoided congestion rents."

And in your response, you say:

"MRP is expected to result in both a more efficient commitment of thermal units, as well as the introduction of locational marginal pricing. To the extent MRP will address this over commitment, the need to export energy over commitment resources of the client, LMPs will, all else being Equal, ensure the investment occurs in parts of the grid where it is most needed. In doing so, it should reduce curtailment of unnecessary exports."

Can I ask you to explain what you mean by unnecessary exports in this context?

MR. LUSNEY: So, from a -- if you have an over commitment of generation due to the algorithm that determines scheduling and dispatching, and you have this over commitment of generation in real time, you need to push that generation somewhere.

So you can either curtail it, or you might export it.
MR. YAUCH: If I can just follow up on that. The market sales panel has extensively looked at the over commitment through what is known as the real time GCG generator cost guarantee program.
When you over commit gas resources that you have to run at a certain point, you may end up exporting when you don't actually have to have them running because you have overcommitted. So that is kind of what we're getting at with that comment.
MR. RUBENSTEIN: Let me understand. MRP, let me take that and understand. MRP's impact on your analysis recognizing that there is a delay in the implementation of MRP?
I take it in your view, MRP is likely to reduce exports, all else being equal?
MR. YAUCH: In cases where there has been particularly severe over commitment of certain thermal resources, yes. But that is not the main driver of exports in any way, shape, or form in Ontario.
So we think even that impact would be pretty small.
MR. RUBENSTEIN: Okay. Insofar as the analysis in your report, what type of analysis -- if this was in place, for example -- and I recognize this is hypothetical and you are using actual data. But if this was in place between 2018 and 2021, what type of impact would that have on the analysis you provided?
MR. YAUCH: I can't give a number, to be honest. But I

don't think it would be material.

MR. RUBENSTEIN: Okay. Can I ask you to go to Power Advisory's response to SEC 2 -- no, sorry, I apologize. It's SEC 3.

So we asked you in this interrogatory that Power Advisory notes with respect to hydro electric generation that it is selling -- selling supply at a loss reduces economic efficiency of the wholesale market, but occurs often in Ontario, the combination of the hybrid design and surplus base load generation.

"Please provide Power Advisory's opinion on how much of this is caused by incentives of OPG's hydro electric incentive mechanism and the existence of this surplus base load deferral and variance account as opposed to operational features of hydro electric generation."

In your response, you say:

"Power Advisory was not retained to analyze the role of the hydro electric incentive mechanism or deferral accounts as part of this proceeding."

I understand that. I don't dispute that is not -- I was wondering if you do have any views on this, and I will give you the background of why I am asking.

I am trying to separate the benefits of exports as set out in your report and their impact on say reducing hydro spill, that is a function of elements that are within the OEB's control. As you know, the OEB approves the hydro electric incentive mechanism and approves surplus base load generation, and what is not in their control.

As you -- just for the background, as you may be aware or may not be aware, in previous Ontario power generation settlement -- approved settlement agreement in EB-2020-0290, there was an agreement that for a certain amounts of the SBG, balances will be deferred under the premise that potentially maybe some of that is not prudent -- or at least my take on that is maybe some of that -- the OPG's use of the account is has not being prudent, as well as the hydro electric incentive mechanism will be dealt with and there may be a reconsideration of that at the time before MRP needs to be implemented.

Do you have any views on this?

MR. VELLONE: I am going to cut in, Mark. I think the witnesses answered the question that was asked in the IRs the way they did because they weren't retained as part of this proceeding to look at that.

If you want to conduct discovery on the HIM mechanism, then I think the proper forum to do that is in an OPG proceeding, not here.

MR. RUBENSTEIN: So you won't let your witnesses provide an opinion?

MR. VELLONE: The original stands -- the original response stands.

MR. RUBENSTEIN: Okay. Well, maybe I will put the question like this, as not an opinion but much more of a factual question about their analysis.

Would the -- the economic analysis that you provided about exports, the reduction in the export transmission service or the increase in the ETS rates, impact on -- the system benefit from reduced hydro spill, would that -- is that impacted by the design of OPG's hydroelectric incentive mechanism, the existence of the surplus baseload, DVA?

MR. LUSNEY: I think simplistic and straightforward answer, as we have noted, the system is a fixed-cost system, primarily.

So for all intents and purposes, yes, because it is rate-regulated, along with contracted. So that uniqueness to Ontario impacts -- has an influence on -- or ETS would have an influence because of that fixed-cost system.

And the second part is, we have a significant amount -- a large amount of baseload generation in this province compared to neighbouring jurisdictions.

MR. RUBENSTEIN: And so insofar as those mechanisms change, they may have an impact -- all else being equal, they would have an impact on the benefits of exports, as you quantified them in your evidence?

MR. LUSNEY: Yes.

MR. RUBENSTEIN: Okay. Thank you very much. Can I ask you to go to SEC -- your response to SEC 12. And so we had asked you to -- assuming that IESO's surplus baseload generation forecast is accurate, please discuss how it would impact Power Advisory's analysis, and you provide a response there.

I just want to clarify and ask maybe if you can confirm at least one part of my understanding of that.

Would you agree there will be less exports than there would otherwise be if there is less SBG?

MR. LUSNEY: I think the core of the answer is, if there's less lower-price hours -- which are reflective of SBG -- or is related to SBG events -- we would expect less exports because of the price arbitrage with neighbouring jurisdictions.

MR. YAUCH: We should add to that, because the IESO talked about this a lot yesterday, that there is a yin and yang to this, that what happens in Ontario SBG is also what is happening, let's say in New York and Michigan, that if they suddenly become a very high-priced jurisdiction, it doesn't matter if we have SBG. It will start flowing there anyways, because that is the economic opportunity.

MR. RUBENSTEIN: Fair enough. So all else being equal, less SBG in Ontario will involve less exports, correct?

MR. YAUCH: Yes.

MR. RUBENSTEIN: Can I ask you to go to your response to VECC 17. This is really just following up on, sort of to cut this short and follow up on a question in your discussion with Mr. Harper earlier.

So in 17 -- so if you just scroll up to the question. So this -- you were asked about a -- you were asked in your discussion with Mr. Harper about figure 14, that shows essentially the sensitivity between HOEP and exports in your evidence.

And the question asks about, have you done a sort of a statistical FIT analysis, such as a regression. And in your response -- go down -- you say:

"It is a linear trend line and is simply there to show a high level of relationship between HOEP and exports at one inter-tie."

So I take it you -- so I took it from your response and your discussion you didn't do any statistical FIT analysis.

MR. YAUCH: Not as part of this evidence that is included here, so -- but our evidence was based on the methodology described. We do a lot of other analysis on our own, but in the context of this evidence it was the methodology we walked through with Bill Harper.

MR. RUBENSTEIN: And I was a bit unclear. Can you do the analysis? Because the figure shows a trend line, and presumably you just did this in Excel, the trend line?

MR. YAUCH: Yeah --

MR. RUBENSTEIN: And then it will give you the, for example, the R-squared statistical fit of that trend line.

MR. YAUCH: You can, yes. We can do the regression analysis. We just, we thought our methodology was much more transparent and easy to follow than just throwing up, you know, regression analysis to parties in the proceeding and the panel.

MR. RUBENSTEIN: Well, can you provide the trend line -- the statistical just [audio dropout] to the trend line you provided in figure 14?

MR. YAUCH: Yes. Yes. I don't know if that is an undertaking or --

MR. RUBENSTEIN: I am waiting for Mr. Sidlofsky there. It was magic, but...

MR. SIDLOFSKY: Sorry about that. Just a small technical problem there. Yes, we will give that an undertaking number, JT2.1.

UNDERTAKING NO. JT2.1: APPRO TO PROVIDE THE UNDERLYING STATISTICS OF THE TREND LINE PROVIDED IN FIGURE 14.

MR. RUBENSTEIN: All right. I am almost done. Can we go to attachment --

MR. SIDLOFSKY: I'm sorry. Just for the benefit of the reporter, I just want to make sure that everyone understands the undertaking. Mr. Lusney or Mr. Yauch, what are you prepared to do.

MR. YAUCH: I believe it is to provide the underlying statistics of the trend line. Is that correct?

MR. RUBENSTEIN: Yes. So figure 14 in your report.

MR. YAUCH: Yes.

MR. SIDLOFSKY: Thank you.

MR. RUBENSTEIN: Can I ask you to go to attachment A to your interrogatory responses. This is the detailed methodology. And some of your discussion with Mr. Harper was clarifying to me, so I have some less questions, but I do have a couple.

Can we go to step 8 and 9. And it is really step 9 where you assume the cost of curtailments applied to be 50 percent of curtailment. Do you see that?

MR. YAUCH: Yes.

MR. RUBENSTEIN: And you were asked in VECC 27.2 about, similarly, where does the 50 percent come from. Maybe we can pull that up. And to be honest, I still don't know why you chose 50 percent and not any other number.

MR. YAUCH: It is very simple. It was a simple average, because we don't have access to hourly data in curtailment, so we can't -- any other number would just be us guessing as well. So we sort of took the King Solomon approach and cut the baby in half.

MR. RUBENSTEIN: So maybe you can just help me understand why -- so first of all, what was the basis of the discount, of having a discount? In your view it is clearly not 100 percent and it is obviously not zero. So maybe you can just talk about the need for some discount.

MR. YAUCH: I will go first, and then I well let -- I think Travis has comments too. Throughout our whole analysis -- and I think the IESO mentioned this yesterday as well -- we tried to be very conservative. We didn't want to overcount. So this is one of the areas where we said, well, we don't have the hourly curtailment data. We asked for it in the IESO. They didn't provide it. They don't provide it publicly.

So we said, how are we going to discount it, because we can't just make up all of these numbers that are going to be lost because you change to ETS, so we came up with what we thought was a compromise. But throughout the report we had to do that, right, so we didn't look at nuclear curtailments, even though they're wildly expensive. Nuclear plants would cost a lot more money. We didn't count that.

So we tried to pull back and be as cautious or conservative as we thought was, you know, methodologically sound.

MR. RUBENSTEIN: Okay. Can we go back to Appendix A. No, actually, no. I think we're okay. You've answered a number of other questions I had in your discussion with Mr. Harper.

Can we go to page 46 of the report. And in 45 and 46 you provide, I guess, the table of your analysis of what happens if the ETS rate goes to zero, and there is a similar table that shows what happens if the ETS rate goes to the higher end.

I just want to ask about the allocation of the benefits or if it goes higher, the allocation of the costs, you know, for a second.

So am I correct that the financial benefits in this table as it relates to reduced spill and curtailed wind for a customer, they see that as a reduced global adjustment.

MR. LUSNEY: Yes, I believe that's correct.

MR. YAUCH: The 33 million dollars, there's a bunch of stuff in there. There is the ICP which yesterday I think the IESO and Hydro One agreed to provide a detailed accounting, so you will see where the ICP revenue flows to.

MR. RUBENSTEIN: Let me just pause you. I was actually looking at two specific lines here, that is the reduced curtailed wind and the financial benefits of reduced hydro sales.

I am just talking about those two lines. And am I correct that those benefits, because of the ICI program, have a greater benefit on class B customers as opposed to class A customers?

MR. LUSNEY: We haven't done -- as part of this evidence, we haven't done analysis to look back at the split between GA payments to class A and class B as defined in the regulation.

So our answer is, qualitatively class B pays more on an energy basis than class A, due to the current capability of many class A customers to manoeuvre through -- manoeuvre down during the 5 [audio dropout] peak.

So I can generally agree, but that is based off of, you know, a qualitative understanding of what's going on. We haven't done any analysis to underpin that. And again, that is from an energy basis, not necessarily a demand consumption basis for global adjustment charges.

MR. RUBENSTEIN: And the reason I ask this is I am just trying to understand, assuming that the net impact to ratepayers was zero, right. It had no impact, right. Just the way the math worked, it had no direct impact.

I want to understand the different allocation to customers of, for example, an ETS rate that flows through, you know, that flows through the UTRs, that flows through the customers to their retail transmission rates verses what I would call supply benefits which will flow up on a different basis.

So do you have any views on that?

MR. LUSNEY: I think back to earlier comments we made to Mr. Bill Harper, that these are all considerations the panel needs to look into in terms of how the whole structure holds together, and therefore, in making any changes to design a rate, you know, how -- which subset of customers are going to be impacted and the magnitude.

MR. RUBENSTEIN: In your report and in your discussion with Mr. Harper today and some of the IR responses, I think you fairly -- to be fair to you, you recognize there are limitations in your analysis due to the information that you have as compared to the IESO. Correct?

MR. YAUCH: That's correct.

MR. RUBENSTEIN: But would you agree, or do you agree that the IESO has the information to do a much more rigorous analysis to provide -- to be able to determine with much greater precision what are the benefits or the harms to changes in the ETS rate?

MR. YAUCH: They should be able to. As we highlight many times, if you had the export bids, you would very clearly see what a near five dollar increase in the transactional costs of moving energy would be.

So in the -- and the IESO would clearly have access to that data.

MR. RUBENSTEIN: In your view, having that information would have allowed for a much more precise analysis?

MR. YAUCH: Yes. You would have been able to narrow the quantity impact. Additionally, the IESO has much greater insight into the operational impact, having to run the control room and everything like that. So they would be able to isolate some of those more operational impacts that we avoided in our study.

MR. RUBENSTEIN: And by precise, it would really be a much more accurate impact analysis. Correct?

MR. YAUCH: Yes. I know the IESO yesterday said directionally they agree with us. But, yes, I am assuming their number would be more accurate.

MR. RUBENSTEIN: Okay. Thank you very much. Thank you very much for your answers.

I don't know, Mr. Sidlofsky, if you want to take a break now. I may have one more question, but I would just like the break to confer with someone. But I believe that is all.

MR. SIDLOFSKY: Why don't we take the break now, then, Mr. Rubenstein. That will give you a chance to think about that. And for the panel, you have also got to think about Mr. Harper's question.

So I think what I will do is, let's say we will come back at 11:05. That will give you a few more minutes.

Panel, do you think you need any more time than that to consider Mr. Harper's issue?

MR. YAUCH: No. No, it will be pretty easy.

MR. SIDLOFSKY: Sorry, Mr. Rubenstein?

MR. RUBENSTEIN: No, go ahead.

MR. SIDLOFSKY: We will reconvene at 11:05. Just one reminder to Hydro One. I guess, Mr. Myers, you are up next. I believe you circulated a compendium, correct?

MR. MYERS: That's right.

MR. SIDLOFSKY: So I'll tell you what, why don't we mark that now, just so we don't lose track of that. The Hydro One compendium will be Exhibit KT 2.1.

EXHIBIT NO. KT 2.1: HYDRO ONE COMPENDIUM FOR APPRO PANEL 5

MR. SIDLOFSKY: And that takes care of that and we'll get started after the break. We will see you at 11:05. Thanks.

MR. RUBENSTEIN: Actually could I be put out in a breakout room with Mr. Harper, if that is possible for just a minute.

MS. SANASIE: Sure.

--- Recess taken at 10:47 a.m.

--- On resuming at 11:06 a.m.

MR. SIDLOFSKY: Let's go back on the record.

Okay. We're back. And I understand Mr. Rubenstein has another question. So the way I would like to proceed is by allowing Mr. Rubenstein to finish off, and then I will turn to the panel and ask if they have come up with a response to Mr. Harper's outstanding question. And then we can move on to Hydro One.

So Mr. Rubenstein, why don't you continue with your questioning.

MR. RUBENSTEIN: Sure. I have had a chance to consult with Mr. Harper. And we would like to ask for an undertaking. You have provided in your interrogatory responses an Excel spreadsheet that includes essentially some of the underlying data that you utilized for your report, and you have also -- or at least some of the data that you utilize for your report. You also provided the methodology, a sort of step-by-step methodology, in Appendix A.

But what parties either asked you, directly or indirectly, for, but I will ask you directly now, is what you didn't provide is the specific actual calculations, not sort of a methodology. Presumably you have that for the underlying numbers in table 3 and table 4 of your report. Would I be correct?

MR. YAUCH: That's correct, yes.

MR. RUBENSTEIN: And can you provide that, please?

MR. YAUCH: We're going to do a breakout room and then we will come back, if that is okay.

MR. RUBENSTEIN: Sure.

[Witness panel confers in breakout room.]

MR. LUSNEY: Thank you, Mr. Rubenstein. We will not provide the calculation engine. The reasoning is, that model is a proprietary model and, in our view, is commercially sensitive and valuable to our firm in how we operate.

The data we provided -- and I think we want to be very clear on this -- is not just the publicly available data. We provided for all intervenors and stakeholders compiled, cleaned, and adjusted data from various sources, and so there is a significant amount of work that's gone into that that we are sharing on the record.

We struggle to go the next step further into how much commercially sensitive information we are providing. You're on mute, Mr. Rubenstein.

MR. RUBENSTEIN: So I don't -- if it is commercially sensitive, I am not entirely clear. I mean, I'm not seeing what you are seeing, so I am not entirely clear what the back end is.

So then I take it you didn't take the spreadsheet information and do a set of calculations? There's something else that you --

MR. LUSNEY: The set of calculations is a model that we have developed, and sharing it means that other people can take our model and perform services for other clients with our work, without any value coming back to Power Advisory as a firm.

MR. RUBENSTEIN: So to me that is a reason why that is a confidential -- that should be filed with the Board for the purposes of confidential treatment, and your explanation seems to be one that the Board would generally have no issue, as previously agreed to. But I don't understand how -- it is not a basis for a refusal.

MR. VELLONE: I will chime in, Mr. Lusney. We understand how the confidential filing guidelines and processes work. The model is of such a level of commercial sensitivity to Power Advisory that it is a refusal, because those -- that process does not provide sufficient protection.

MR. RUBENSTEIN: Can you elaborate on that last part?

MR. VELLONE: I'm casting myself into their position here, but I expect the issue is many of the entities that they would view as competitors are actually party to this proceeding. Could easily sign a declaration. Get a copy of their model. And then use it without ever paying for it.

MR. RUBENSTEIN: Okay. I mean, even though presumably that would be in breach of the confidential -- the declaration undertaking.

MR. VELLONE: We don't know what people do with data once we let it out of our hands.

MR. RUBENSTEIN: Okay. And just maybe for my own clarification, was this model developed for the purpose -- is this model developed for the purposes of this report? Or was this a model that is -- existed before you were asked to do this report and it is used for other purposes? I am trying to understand what we're talking about here.

MR. VELLONE: I will allow the witnesses to respond to this one.

MR. LUSNEY: Can you let us think about it, in terms of how -- like, we understand where you are going. I think our legal representative had given it thought. I am trying to think through the process here. We are trying to be -- we're trying to be as helpful as we can to stakeholders and the Board, but we also are recognizing our long-term economic viability as a firm.

MR. RUBENSTEIN: Okay. Well, I guess where we are is, how about we take it as an undertaking with a sort of an -- as an advisement qualification?

MR. YAUCH: Agreed. I will say the data we provided and the methodology -- like, you can do the calculation. It is all there. We cleaned it all. Everything -- like, we've gone and done it for you really, so all you just need to do is the calculations. That was why we gave that initially. So I just want to leave that there. But we will take it as an undertaking and we can address it later.

MR. RUBENSTEIN: And I can just say that Mr. Harper and I have been attempting to do that, and it is not as simple as you're saying.

MR. YAUCH: Oh, I know.

MR. RUBENSTEIN: And we would like to -- and obviously seeing the underlying math is important. So I guess that is where we are.

MR. SIDLOFSKY: So we will make that undertaking JT2.2.

UNDERTAKING NO. JT2.2: APPRO TO TAKE UNDER ADVISEMENT THE REQUEST FOR THE MODEL ON WHICH POWER ADVISORY'S CALCULATIONS ARE BASED.

MR. SIDLOFSKY: And just again for the purposes of our reporter, would the undertaking be to take under advisement the request for the model on which Power Advisory's calculations are based? Feel free to chime in if it is something different than that.

MR. YAUCH: That is better than I can do, so I think that is fine.

MR. SIDLOFSKY: Mr. Rubenstein, you okay with that?

MR. RUBENSTEIN: Yes. I will just specify, we're looking for the underlying calculations as we understand that is contained in a model, and that is where the model issue arises for it, so, you know, it's the underlying math, as I understand it, is in the model, but it is the math that we're looking for. Presumably I'm not saying this can't be done. I don't know. If it can be extracted or something, obviously, that would be simply as sufficient, right, for our purposes.

MR. SIDLOFSKY: Okay. Thanks for that.

Mr. Rubenstein, did you have more?

MR. RUBENSTEIN: No. Thank you very much. Those are my questions. Thank you for your assistance.

MR. SIDLOFSKY: Thank you. And panel, back to Mr. Harper's outstanding question.

MR. YAUCH: Yes, so I just want to reiterate the question was to the exact number that we use for hydro curtailments over the 2018 and 2021 period. So the number is 4,153,586, which is quite precise.

MR. HARPER: And that's terawatt-hours.

MR. YAUCH: That's megawatt-hours.

MR. HARPER: Megawatt. That's right. I just wanted to make sure we had the units right.

MR. YAUCH: It would be 4.1 terawatt-hours.

MR. HARPER: Right.

MR. SIDLOFSKY: Mr. Harper, I will give you a chance to follow up on that if you have any other questions. Or was that it?

MR. HARPER: No. I have no more questions. Thank you very much for getting the information for me.

MR. SIDLOFSKY: Thanks, Mr. Harper.

So we are on to Mr. Myers, Hydro One.

EXAMINATION BY MR. MYERS:

MR. MYERS: Thanks very much. And just a reminder that we filed a short compendium this morning, which was marked as KT2.1, so I will be referring to that, as well as certain interrogatories. And thank you to Mr. Boyle for putting that on the screen.

So can we start by turning to Staff 1, please. And regarding the statement in your report that export traders pay congestion rents that are used to offset a portion of transmission related costs, OEB Staff asked you who explain whether and how transmitters receive congestion rents.

I just want to understand your response. You responded that the IESO is a transmitter under Ontario law because a transmitter is a person who operates a transmission system, and the IESO operates the bulk transmission assets in Ontario, so therefore it is your view that they are a transmitter.

And in its role as a transmitter, they receive congestion rates, which they distribute pursuant to market rules. Have I got that right?

MR. LUSNEY: That was the summary we provided, yes.

MR. MYERS: So I am going to ask you about distributing those amounts in a moment. But first I just want to understand your view that IESO is a transmitter under Ontario law.

You referenced the definition of transmitter from section 3 of the OEB Act, and we have that in the compendium.

Other than that definition, did you consider anything else in arriving at your view?

MR. LUSNEY: I am a professional engineer by trade, not a lawyer. So trying -- that was my interpretation, or our interpretation in terms of preparing a response. So I think that is what we considered in terms of coming to that statement in response to OEB Staff 1.

MR. MYERS: Okay. Are you aware that the IESO was established and gets its powers under the Electricity Act?

MR. LUSNEY: Yes.

MR. MYERS: And that the IESO -- the objects of the IESO under section 6 of the act?

MR. LUSNEY: Yes.

MR. MYERS: And under section 6 of the Electricity Act, there is a whole long list of the objects of the IESO. And I have highlighted a couple that I think are most relevant, which include to direct the operation of the IESO grid and to enter into agreements with transmitters that give the IESO authority to direct the operation of their transmission systems. Do you see that?

MR. LUSNEY: Yes.

MR. MYERS: Do you agree with me that the listed objects of the IESO do not include either the ownership or the operation of transmission systems?

MR. LUSNEY: I think when you walk through this way and the way I interpret it, or we interpreted it previously, I can see where you are heading in terms of direct versus operate. And I think that is again, not being -- not being legal -- not being a lawyer, did not land on the exact wording for that. So I can agree with where you are heading.

MR. MYERS: So I am not going to take you to the IESO's licence abilities, but I guess just to jump ahead, you agree that there is a distinction under Ontario law, then, between on the one hand, owning and operating a transmission system and on the other hand, directing the operation of the provincial transmission system?

MR. LUSNEY: Based on your --

MR. VELLONE: You are asking him for a legal conclusion?

MR. MYERS: I am trying to get to an understanding of the statement in their response.

MR. VELLONE: Maybe try to rephrase the question. I heard you asking him for a legal opinion on something and maybe you could rephrase the question to get to where you are going.

MR. MYERS: To be fair, they provided somewhat of a legal opinion in their response, so I think it is fair that they explain that view.

Let's cut to it. Do you agree that the IESO is not a transmitter?

MR. LUSNEY: Can we just take a quick breakout room?

MR. MYERS: Sure.

[Witness panel confers in breakout room.]

MR. LUSNEY: Thank you, Mr. Myers, for the time. In our response, it was coming from the IESO's operating the system through dispatch instructions and real time operations, and that is how we came to a transmitter.

I am not a lawyer, so I think for a direct conclusion of what it is, I think we're not as confident in the answer we gave in the IRs and would have to, you know, reconsider exactly and probably seek legal advice to what the exact answer would be.

MR. MYERS: Okay. So if we can at least assume that the IESO's not a transmitter, but rather its purpose is to direct the operation of the grid, could you just clarify your answer to OEB staff's question of whether and how transmitters receive congestion rents?

If the IESO is not a transmitter, do you still believe the transmitters receive congestion rents?

MR. YAUCH: We were under the assumption that the funds flow into the TRCA -- that was discussed at length yesterday -- and then that money flows to transmitters.

But based on the discussions today, and us in fact asking Hydro One and IESO to provide a detailed settlement you know, examples, it may be the funds flow slightly different than the way we thought it.

But ultimately, it is a bit of a black box in how the money goes to the TRCA to a customer at the end of the day. So we did kind of respond to Hydro One and say we're open to provide a detailed settlement because no one can really see it from the outside other than the IESO, and transmitters or distributors, whoever is getting it.

MR. MYERS: Okay. Thank you. Just give me a moment. I will see if I still need to ask some of my remaining questions.

I think it probably makes sense that the remaining questions will get clarified through the undertaking that you referenced there.

So I am not going to attempt to take you through some of the market rules -- and I see big smiles from that.

[Laughter]

MR. YAUCH: You made my afternoon, I guess.

[Laughter]

MR. MYERS: All right. I think I will leave it there. Those are all of my questions. Thank you.

MR. SIDLOFSKY: Mr. Myers, thanks very much. Let's go to Energy Probe. Mr. Ladanyi?

EXAMINATION BY MR. LADANYI:

MR. LADANYI: Good morning, panel. My name is Tom Ladanyi. I represent Energy Probe, and both of you know me, of course. I will have a few questions of clarification to the responses, to the interrogatories that were asked. Mr. Harper actually already referred to some of my interrogatories, so probably my questioning may be a little shorter.

So can we go first to PA-Energy Probe-5, PA-EP-5. So in the preamble, I quoted from your evidence, page 16, paragraph 49 where you say:

"This opportunity service targets excess capacity in the system that is being inefficiently used by existing domestic demand."

And in part A, question A asked:

"Does Power Advisory suggest that any system that has spare capacity is inefficiently used?"

And then you replied in response A that:

"The efficient use of a fixed cost system or any economic system is to maximize its utilization. The more throughput that can be accommodated and revenue generated as a result of that throughput, the lower will be the per unit cost."

I think that is basic economics.

"But this only occurs if the additional unit does not increase fixed or long term costs. A transmission grid that is built to accommodate peak demand will have spare capacity in most hours"...

And you have 8759 in the brackets, which I assume is the number of hours in a year. Is that right?

MR. LUSNEY: That is correct.

MR. LADANYI: So as far as you are concerned --

MR. LUNSEY: To be clear, number of hours, less the peak hour. So 8760 would be the number of hours in a year.

MR. LADANYI: I was wondering. So there is one peak hour and then the rest is other hours, non peak hours.

MR. LUSNEY: Correct.

MR. LADANYI: Why would that be? Can you tell me that first?

MR. LUSNEY: Well, when you look at a load duration curve for the system over a year -- a low duration curve stacks consumption from highest to lowest -- you would have your peak hour, which is the most consumption, and reasonably would expect the system to be highest utilization. And if you planned the system for that year to meet that peak hour, it would be full utilization. Then all other hours, which have less consumption, would have less utilization, so you would have spare capacity.

MR. LADANYI: And then a second question I actually asked in part B, is not spare capacity needed to rapidly respond to changes in demand and supply? Would not a system with no spare capacity have reliability issues?

And you basically agreed with that. And I have got issues here with actually your answer. I won't read it. But I assume that IESO or for that matter Hydro One determines how much spare capacity there has to be on the system for reliability. And then whatever is not needed for that, they would, I guess, release. Is that how it works?

MR. LUSNEY: The answer is more nuanced. So the amount of flow capability in the system is set under -- "set" maybe is not the right word -- is determined under certain reliability requirements. So the easiest example that I can give is you have two transmission lines, and the reliability requirement is the ability to maintain flow on those lines if you lose an element, so lose one of the transmission lines.

So from a reliability purposes, you have more capacity than you allowed to flow. So that is reliability capacity, which is much higher than system flow capabilities, where you are not using that full capacity that's been allocated.

So for round numbers, if you had two lines -- and there's a lot of other nuance, but I won't -- two lines of 100 megawatts each, the system operator would say, well, I'm only going to flow 100 megawatts on this line, or on these lines, because if I lose one I can load up the other line to 100 megawatts. If -- so you could flow 200 megawatts, but you would have reliability problems.

When we talk about spare capacity, we're primarily talking about 90 megawatts flowing on that line. You have 10 megawatts of underutilized capacity respecting the reliability criteria.

MR. LADANYI: So would the exporters know this? Or how would this be determined?

MR. LUSNEY: They would not necessarily know it. That is what real-time operation -- that's part of the reason why the IESO is proposing to move to locational marginal pricing, to give some pricing signal with respect to congestion or constraints in the operating system, and for exporters the only really insight that they have is inter-tie congestion pricing, which provides -- and published values, which provide the amount of transfer capability over inter-ties, but the whole system is determined essentially through load flow models on a five-minute basis through the algorithm and respect operational constraints, which would include transmission constraints.

MR. LADANYI: But that would not be visible to outside parties. Only IESO would know that. Is that right?

MR. YAUCH: Exporters will see prices, and the vast majority of prices or exports occur when prices are 15 dollars and below. That is clearly when you're only running hydro and none of the thermal units in Ontario. So it is clear at that point that demand is well below the capacity of the system, whether it is in terms of generation or transmission. An exporter will see that price signal and act accordingly.

MR. LADANYI: All right. We can continue this discussion at the, I guess the follow-up technical conference. This is interesting.

Can we turn to your response to Energy Probe number 6, PA-EP-6. And I think Mr. Harper took you to this. And in question A I asked:

> "Please explain how a cost allocation methodology would recognize an economic opportunity and use it in setting rates."

And what I was looking for was an explanation. And there does not seem to be any in your response to A. Can you explain to me how this cost-allocation methodology that you think would be the correct one would recognize an economic opportunity? How -- numerically, what would they do?

MR. LUSNEY: So I think, as we responded to Mr. Bill Harper, we haven't provided as part of this or have not completed as part of this evidence jurisdictional scans on cost allocation for opportunity-type services. We are just trying to provide guidance that you would approach this from a different methodological approach, recognizing that the users of the system have very different objectives and are treated very different, both from a planning and operational point of view.

I don't really have a calculation answer, but we're just trying to provide, you know, guidance based on our expert opinions.

MR. LADANYI: I understand that, and I -- since you're more or less recommending this being a good way of doing things, I was just trying to understand in a very kind of simple, high-level way how this would work. Can you please tell me that?

MR. YAUCH: What our evidence says is any cost allocation should consider that. What we say in our evidence is that the current way in which you allocate spare transmission capacity and recover the costs of that capacity from exporters is a pretty efficient and market-based and transparent way of doing it. So our evidence is clear that the current methodology is sound and that if you are going to go to some cost allocation model way of doing it, here are some ways. But we were clear that the current methodology of doing it, which is unique to Ontario, is actually sufficient.

MR. LADANYI: All right. I won't press you any more on this. By the way, let me ask you one more question.

Economic opportunity. Can there be many economic opportunities?

MR. VELLONE: Sorry, for the sake of clarity with the last response, what did you mean by "current way of doing things", exactly?

MR. YAUCH: The current methodology of allocating prices, taking prices on inter-ties, collecting rents, and allocating those rents back to Ontario consumers.

MR. VELLONE: You meant the ICP?

MR. YAUCH: Yes.

MR. VELLONE: Thank you.

MR. LADANYI: All right. You didn't mean the ETS?

MR. YAUCH: No. We're talking about how you allocate transmission capacity through the ICP and IZP.

MR. LADANYI: Okay. Well, I am glad for the clarification, because I was assuming it was ETS, and I was surprised by your answer, but anyway, thank you for clarifying it.

Now, coming back to ETS. Should the ETS rate increase or decrease when there is an economic opportunity?

MR. LUSNEY: Our evidence and what we have been retained is just to provide the impact of a higher -- estimate the impact of a higher or lower ETS. We don't have an opinion.

MR. LADANYI: So -- of course. And I know that. But conceptually as experts, which you, I guess, claim to be -- we haven't challenged that yet -- is that ETS rates should respond to economic opportunities.

How would an ETS rate respond to economic opportunity?

MR. LUSNEY: Similar to our responses to Mr. Bill Harper earlier, there is a lot of considerations in terms of doing it from an ETS rate point of view, and to your question, I mean, one aspect to consider is the time function of the response.

Should it be responding in real time? Should it be responding yearly? And that is stuff that we haven't taken time as part of this preparation of this evidence to consider, or to calculate or analyze.

MR. LADANYI: So I am just trying to understand the dynamic nature of what is being discussed. So ETS rate, if it is variable, and it would vary -- as a variable would respond to economic opportunities as they arise, would it increase or decrease when there is more economic opportunity?

MR. LUSNEY: We haven't considered a variable ETS rate.

MR. LADANYI: You have not? All right. I thought you were considering it a dynamic one. So it is my fault. Probably I misunderstood it.

Now let's go to Energy Probe Number 10. Here in your evidence on page 30, paragraph 74, you say:

"A regulated process would typically only be used when there is a market failure. In this case, there is no market failure on the province's inter-ties."

So I actually asked you to define market failure. And you provide an answer. You say:

"Market failure can mean a number of things. Typically, Power Advisory assumes a market failure occurs when there is abuse of market power or lack of competition."

So is there evidence of abuse of market power or lack of competition in Ontario?

MR. YAUCH: Well, we only looked at the inter-ties, so as far as we know, no.

MR. LADANYI: So if I understand your evidence -- which I just read in the preamble and your response -- you're saying there is no need for a regulated process for an export rate?

MR. YAUCH: In this situation, the way Ontario has designed its inter-ties and the market processes on those inter-ties, we don't view it as a market failure.

We think it allows for open and transparent competition amongst market participants that sets a price that allocates transmission capacity efficiently.

MR. LADANYI: I am still trying to make a conclusion out of your responses here and your evidence. You're saying because there is no market failure in Ontario, we do not need -- we being Ontario really does not need an OEB regulated export transmission service rate. Is that what you are saying?

MR. YAUCH: Our view is the current process allows for transparent open competition, which is what a market is supposed to achieve.

MR. LADANYI: I will have to ponder these responses. Anyway these are all of my prepared questions. I have no further questions. Thank you very much, panel.

MR. SIDLOFSKY: Thanks very much, Mr. Ladanyi. We will move on to AMPCO. Ms. Grice.

EXAMINATION BY MS. GRICE:

MS. GRICE: Thank you, and good morning, panel. I just have a couple of clarifying questions. The first one is with respect to Staff 4. Thank you.

Staff 4 is asking a question regarding table 1, and table 1 is the financial impact of increasing and decreasing the ETS rate, and Staff has asked questions regarding the congestion rent.

And then in part A, Staff asked for an explanation of how much of the estimated change in congestion rent would flow to transmission rights holders versus Ontario ratepayers.

And I just have a clarifying question regarding the response to part A, and it is the last sentence of the response where it says:

> "Under the current methodology of TRCA disbursements, nearly 98 percent of disbursements flow to Ontario ratepayers."

So I just wanted to clarify if this means that generally payments to rights holders is near 2 percent, is that what we can take from the response?

MR. YAUCH: No. So the TRCA is money that is collected from the combination of auction revenues, TR auction revenues and then congestion rents, minus payments to TR rights holders.

Previously, the money that was collected in that account flowed to exporters or domestic customers based on volumes. And so at that time, exporters got about 13 percent, domestic loads got about 87 percent.

Based on a bunch of reviews that the IESO did on behalf of the many -- in many cases, on behalf of the market surveillance panel, they changed that allocation to allocating money from the TRC disbursement based on transmission costs paid.

And so 2 percent is essentially what the ETS paid by export customers as a percentage of total cost of the transmission system. So that is how it is allocated now.

MS. GRICE: Okay. I appreciate that.

MR. YAUCH: If ETS was zero, it would be 100 percent domestic loads.

MS. GRICE: Okay, thank you. Then I just have one last question. This has been talked about a lot, about the relationship between the ETS rate and the ICP.

I don't think we need to turn this up, but in IESO's response to OEB number 36, the IESO said that they would not characterize the relationship as a dollar-for-dollar proportional relationship in all cases.

I just wanted to follow up and ask if Power Advisory has a view and could comment and give a directional estimate of what you think the relationship is likely to be. Would it be a greater than or less than one to one? Are you able to comment on that at all?

MR. YAUCH: At a high level, if the ETS increases, it will be likely offset through an export bid.

So if the ETS increases by five dollars, an exporter now has to pay a transaction cost of five dollars and should, in a perfectly efficient market, include that five dollars in its bid and lower it by five dollars, i.e. congestion rent would go down by five dollars.

Export trades happen as a result -- their dynamic happens for lots of reasons, so we don't think it will always be one for one. But it would be an inverse relationship, as the IESO pointed out.

MS. GRICE: You can't comment on whether or not in those other cases, it would be greater than or equal to one to one?

MR. YAUCH: No. I know we hammered it many times that if you had access to bid data, you would probably be able to do a more accurate sort of calculation that you are asking, but we didn't have it to do this.

MS. GRICE: Okay, thanks very much, those are my questions.

MR. RUBENSTEIN: If I can follow up on a response that was given to Ms. Grice?

MR. SIDLOFSKY: Sure, go ahead, Mr. Rubenstein.

MR. RUBENSTEIN: Mr. Yauch, I wanted to follow up on the TRCA disbursement question, the response you provided.

You are more familiar with this than me. I just want to be clear. Based on the current methodology, you said it is based on transmission, contribution to transmission --

MR. YAUCH: Costs paid.

MR. RUBENSTEIN: So if for example the Board were to approve a zero ETS, then is it automatically the flow through impact is that domestic ratepayers will receive 100 percent of the balance.

MR. YAUCH: That is our reading of it, because exporters would then be paying no transmission costs for every single trade of power.

So if Hydro One and IESO in their example, if it ends up being different, we will comment. But our view is it would be 100 percent.

MR. RUBENSTEIN: And the flip side corollary of that, if it goes up to the five dollars or if it is higher, domestic ratepayers will get less?

MR. YAUCH: Right. Like if ETS was extreme, if it was fifty dollars a megawatt-hour and exporters were paying the entire transmission system, they would get everything out of the TRCA.

MR. RUBENSTEIN: Okay, thank you.

MR. HARPER: Jamie, it is Bill Harper. I have one clarification on that as well.

MR. SIDLOFSKY: Sure, go ahead.

MR. HARPER: I just want to ask. All of that discussion on the percentages, that is on what is left in the TRCA, net of what's been paid to transmission right holders. I just wanted to make that clarification.

MR. YAUCH: Yes. Yes, Bill. So I think the IESO provided a table somewhere, but it says here's the TR revenues we get from selling TRs, transmission rights. Here is congestion rent we collected, and here is what we paid TR holders.

So in the end -- yes, sorry.

MR. HARPER: You are talking about the net of that? I just wanted to make that clarification.

MR. YAUCH: That's right. What is left in TRCA is what is there after the auction revenues congestion rents have been collected and paid.

MR. HARPER: Thank you.

MR. VELLONE: If you will suffer a quick redirect because we're already on the topic.

Re-Direct Examination by Mr. Vellone:

MR. VELLONE: Just to clarify when you answered those questions, you are making an assumption that the transmission service charges allocation that the IESO uses is primarily driven from an exporter point of view by the collection of the ETS rate.

But if the IESO also collects uplifts and other charges and includes them in transmission service charges for the purposes of this allocation, it might not exactly be zero. Is that a fair statement?

MR. YAUCH: Yes. If uplifts are used as representative of transmission costs paid, then I guess they would be included in how you do the split from the TRCA disbursement.

MR. VELLONE: Thanks.

MR. SIDLOFSKY: Thanks, Mr. Vellone. Let's move on to Mr. DeVenz, Pollution Probe.

MR. DeVENZ: Good morning. I'm John DeVenz with Pollution Probe. Our questions have been answered this morning, so we have no questions. Thank you.

MR. SIDLOFSKY: Thank you. Anwaatin, Mr. McGillivray.

MR. McGILLIVRAY: Thank you, Mr. Sidlofsky. Anwaatin is in a similar position. We don't have any questions for Power Advisory. Thank you.

MR. SIDLOFSKY: Thanks very much. On to Mr. Pietrewicz for OEB Staff. Last questioner of -- for this panel.

EXAMINATION BY MR. PIETREWICZ:

MR. PIETREWICZ: Good morning. Likewise all of my questions have been answered, so I hope to be brief about it. But I still will ask a couple.

First of all, thanks for being here this morning. I am Andrew Pietrewicz, and I will be asking questions on behalf of OEB Staff.

Let's skip ahead to a question I had and it is timely because others were just asking about it, and I want to get a little bit further ahead on it.

In reference to Power Advisory's response to OEB Staff 4A, Power Advisory's response to staff 4a, and it's the same quote that Ms. Grice was asking about, and it is the place where it says:

"Power Advisory's response has, an increasing ETS or increased transmission [audio dropout] charges paid by exporters and subsequently increase the allocation of disbursements from the TRCA."

And my -- for my own understanding -- and I appreciate your clarification -- are you saying that effectively exporters get some of their ETS costs recouped through the TRCA?

MR. YAUCH: Yes. So when it is all said and done and there is surplus money in the TRCA, they get what is now 2 percent allocated back to them through a payment. While I discussed the history of it is it used to be much higher and now it is 2 percent.

MR. PIETREWICZ: Thank you. Moving on to OEB Staff 3 to Power Advisory -- Power Advisory's reply to Staff 3 --

MR. VELLONE: I can do redirect at the end or redirect right away. It is in your hands, Andrew. I --

MR. PIETREWICZ: Please go ahead, please go ahead, because, Mr. Vellone, I have a different view up, so I don't see who is talking right now. But, yes, please feel free to jump in right away.

MR. VELLONE: So I just want to clarify the witness's response to the last question to understand -- I guess you are making an assumption in that response that the owner of the transmission right, the successful party in the auction, was an exporter.

MR. YAUCH: Yes. So let's be clear. The IESO has looked at this in the past, and there are a certain number of participants -- I forget the percentage. I think it was around 20, 30 percent -- that never exported any energy, but they bought TR revenues, so they would get money as well even though they're not in any way, shape, or form an exporter, they're a financial participant, really.

MR. PIETREWICZ: Thank you. That is actually a very helpful clarification. Thank you. Is that it, Mr. Vellone? Can we move on?

MR. VELLONE: Yes, that was it.

MR. PIETREWICZ: Thank you.

So on Staff -- where were we? Yes, Staff 3B. OEB Staff's question here refers to Power Advisory's estimate. Can I refer to you as PA to save sort of syllables?

MR. LUSNEY: Sorry. I know you want to save time, but can you refer to us as Power Advisory? There is another firm in North America that uses PA, so we have to be more cognizant of being Power Advisory.

MR. PIETREWICZ: That is great. Hence why I asked. As someone with an Anglicized name, I know that appellations matter, and so thank you. Power Advisory.

OEB's staff question refers to Power Advisory's estimate that -- I am quoting here from somewhere -- that the financial impact to Ontario ratepayers from increasing the ETS rate to $6.54 a megawatt-hour would have been a net increase in costs of 42.6 million dollars over the 2018 to 2021 time frame. Right? So OEB Staff is asking you about that, and this is where we get the number of 42.6 million dollars.

And in an interrogatory response, the OEB Staff 3B, Power Advisory confirmed that this 42.6 million dollars is the cumulative total. Right? Over the four years, including 2018, 2019, 2020, and 2021. Right? It is not the annual number. It is a cumulative amount. Okay.

And this -- I am getting to the point. Were you trying to say something, Mr. Lusney? Your microphone is off.

MR. LUSNEY: No, sorry, sorry.

MR. PIETREWICZ: Oh. And when we asked you in this interrogatory to put that 42.6 million dollars in perspective, that cumulative figure, in terms of what the approximate total ratepayer cost over that same period was, that period 2018 to 2021, Power Advisory indicated -- and I will try to find exactly where you say that. It is somewhere in this answer. Oh, yes, it is in part C to this response.

Power Advisory indicated -- and I am quoting:

> "The UTR amounts for 2018 alone totalled more than $1.6 billion."

And wholesale market-related costs typically total more than $19 billion annually.

And so my first question to you -- just help me put this into perspective. There are a couple of numbers here that I would like to put into a world view.

By this -- referencing this 1.6 billion and this 19 billion, are you saying that -- or do you mean that more or less the cost of electricity service in Ontario is in a ballpark of 21 billion dollars a year? That's the 19 billion plus the 1.6 billion?

MR. YAUCH: No. So not that I am disagreeing with you, is that those numbers were just really indicative. So we didn't go through and calculate all of the wholesale costs. We gave an indicative value for transmission, and then there is also distribution costs that are not included in this either.

We just wanted to say that while there is a 42-million-dollar net cost, you know, this is a little sliver of the system, right? And the system is much larger than what we're focusing on in this proceeding. That is not to negate the importance of it. It is just to put it in the context in which it sits.

MR. PIETREWICZ: Sure, sure. Even small things can be important. I am just trying to get a sense of what were the comparators here.

So are you saying, Mr. Yauch, that -- I totally appreciate that, that you are speaking from sort of your expertise and your experience -- that the total system cost annually is 19 billion, you know, market costs, 1.6 billion in UTRs, you're saying, and in addition there are distribution costs to that? So it could be more than 21 billion dollars --

MR. YAUCH: That's right.

MR. PIETREWICZ: -- in a year. Okay. And that's fair enough. I don't want to hold you to a specific number.

So by that kind of arithmetic, you know, over the period 2018, 2019, 2020, and 2021, if we take that kind of round number of, let's say $21 billion, and multiply by four years, would you agree that the cumulative cost for that period of 2018 to 2021 would have been something like $84 billion? That is, 21 billion a year times four years?

MR. YAUCH: For indicative purposes, yes.

MR. PIETREWICZ: Okay. Thank you.

And so I think this is -- and so your estimate, therefore, is that in the report Power Advisory's estimate is that increasing the ETS to the maximum amount posited in the Elenchus study, the maximum amount of $6.54 per megawatt-hour, increasing the ETS to that amount would increase the net costs by about $42.6 million cumulatively, compared to a cumulative cost of about $84 billion. Is that correct?

MR. YAUCH: Yes. But I will highlight -- so we were conservative in our assumptions, and we did that for a reason. And secondly, we didn't look at things like operational costs. I think the IESO mentioned yesterday nuclear shutdowns and manoeuvres. We didn't look at that, because we're not nuclear engineers and we don't operate those plants.

But I think the IESO's comments are fair, that those costs are real, and operational costs are not zero, and that they should at least be considered. And I know the IESO did qualitatively -- they didn't do it quantitatively, but I think that should also be put in the context of 42 million over 82 billion.

MR. PIETREWICZ: Yes, sure, sure, and -- thank you. And the spirit of where I am coming from is really more on what your report said, not what it didn't say. So let's focus on what it said. But thank you for that. That is an additional context.

And so by this 42.6 million compared to a much larger, like, many orders of magnitude larger total system cost, you called it a sliver, I think this is what you mean in your response to part C, that, quote:

> "The benefits and costs you have described here as part of changing ETS are well below 1 percent of total system costs, however they are defined."

That is what you meant. It is a small number compared to a big number; is that correct?

MR. YAUCH: That is correct, yes.

MR. PIETREWICZ: Okay. And, I mean, by "well below", I mean, I know we're rounding here, but by "well below" would you agree that 42.6 million over, you know, 84 billion is actually something like much less than 1 percent? It is not even a tenth of a percent. It is probably in the hundredths of a percent. Would you agree with that, subject to check?

MR. YAUCH: Subject to putting 42 million over 82 million, yes. It is low.

MR. PIETREWICZ: 42.6 million. Okay. And I think you would agree that, you know, five-hundredths or a hundredth of a percent is a pretty slim margin. You would agree with that?

MR. YAUCH: Yes. For Ontario customers. Export customers are different, right? Their economics are different, and this may be much more materially impactful for them. So we're just looking at this in terms of the Ontario -- total costs for Ontario loads, but it is a very different story if we're talking about exporters.

MR. PIETREWICZ: Fair enough. Thank you for that. Yes, we are talking about net impact to Ontario customers when you talk about that 42.6 million dollars.

So continuing on to OEB Staff 3D, we asked Power Advisory what variables this estimated 42.6 million dollars would be more sensitive to, right.

And in its response, Power Advisory said it actually has not conducted a sensitivity analysis of this result. However, you mentioned somewhere -- oh, yes, in part E, that congestion rents will be highly sensitive to the ETS rate.

So although you didn't do the analysis, you did posit one thing or highlighted one thing that the ETS would be sensitive to, or the congestion rents would be sensitive to in part E.

I just want to point out that elsewhere -- you don't have to turn it up -- IESO told VECC at VECC 16.1.2 that changes in ICP are driven by a number of factors.

I believe you mentioned some of them today, including factors in neighbouring jurisdictions, seasonal variations and supply, demand changes in fuel costs, outages, composition of marginal resources that set market price, trade behaviour, et cetera.

IESO said changes in ICP are driven by these things. My question here is would you agree with that, that changes in ICP are sensitive or at least driven by these things?

MR. YAUCH: Yes. So the ICP is set on export bid behaviour. That is what sets the ICP, and then determines ICP.

So exporters will bid for a variety of reasons both in terms of supply conditions and demand conditions in Ontario, but also in whatever market they're moving it to, and whatever transmission constraints or seasonal constraints facing those other markets. They're all going to affect their bid.

If you increase the ETS or decrease it, it creates a transactional cost on top of all of those other things, so that is why we say a change in ETS will -- whatever their bid is, that new transactional cost will change it.

So it will have an immediate impact, in our view.

MR. PIETREWICZ: Thank you. That said, while I think you're saying you are agreeing that the result of your analysis is sensitive to a variety of things, I think you're agreeing that we don't know how sensitive it would be, right, because for reasons of time, scope, whatever the reasons are, you didn't actually conduct a sensitivity analysis in this matter. Is that correct?

MR. YAUCH: No, no, that's correct.

MR. PIETREWICZ: Thank you. Okay. Maybe this is beating a proverbial dead horse, but I want to very quickly kind of go through a couple of instances.

You referred on several occasions in your interrogatory responses and maybe your evidence, I don't recall, about, you know, the challenges you faced with access to data. I just want to highlight some of those.

In OEB Staff 14E, OEB Staff 14E to Power Advisory, we asked you about what the dollar of transmission rights sold to rights holders is that exceeded the dollar value of congestion rents.

Your response was clearly you don't have access to this data. In other jurisdictions, this information would be publicly available. But market data and information is severely restricted in Ontario.

My first question to you in fairness is that, would having data about the transmission rights sold to rights holders that exceeded the dollar value of congestion rents received in the market, would that have been a factor in your analysis in terms of the result of the 42.6 million dollars? I don't want to ask about it, if it is irrelevant.

MR. LUSNEY: No. I think this is a good question, in our view, because when preparing the evidence and what we were retained to do, you know, as our expertise in understanding the Ontario electricity sector, we have to determine a methodology to respond to the questions we have been asked. And that methodology is going to be influenced by the data and information that we know that we can get access to.

And therefore, you don't want to, to serve our client appropriately, propose a methodology that will ultimately fail because we can't have the inputs we need or have to rely on very significant assumptions in that.

So I think to your question on whether it would change our outcomes, maybe it wouldn't, but without -- if the data was available, we might have even come at the methodology of our analysis differently and that is, I think the key point is you are right in saying that we keep coming back to that had this data been available it might have been a completely different approach.

MR. PIETREWICZ: I understand, thank you. I will move on. OEB Staff 15a -- in OEB Staff 15A, it is kind of the same theme, panel.

OEB Staff asked Power Advisory about the sensitivity of export traders to prices, right.

And in part of its response, Power Advisory said that its analysis relied on HOEP, i.e. real time pricing data, as the IESO does not provide historical PD-1 pricing for the inter-ties.

And it goes on, it goes on. And it says that Power Advisory had no way to address this in its modelling given the lack of data, and that you did a valiant effort in using the best available information.

Then in addition, you mention that it is not clear what the sync is for each trade. But my questions to you, can you help me understand how to say this word, is it PD minus one or is it PD-1?

That is the first question. And then tell me what PD stands for.

MR. YAUCH: PD minus one stands for pre dispatch -- one hour pre dispatch, so one hour before real time.

Congestion rents are set in PD minus one, and then they're added to HOEP in real time.

So our calculation of congestion rents, we had to use HOEP because we didn't have the PD minus one historical data and that is why there is probably a bit of discrepancy between ours and IESO's numbers.

MR. PIETREWICZ: Thank you. Would you agree that relying on HOEP rather than PD minus one as well as not being able to determine what the sync is for each trade, would you agree that uncertainty slash modelling was involved in these results?

MR. YAUCH: Yes. It creates greater uncertainty. If you had the export bid, you wouldn't really care what sync is because you would see what their economic opportunity is they're chasing.

MR. PIETREWICZ: Thank you. In response to OEB Staff 16D, Power Advisory highlighted what reporting [audio dropout] your lack of market data available and inability to provide complete analysis in this proceeding.

My question to you is that -- is this data in the context of 16K, again, increasing or adding to the range of uncertainty or fuzziness or approximations inherent in these results?

MR. YAUCH: It is adding to it, but I do want to highlight the second sentence there that you didn't read, that Ontario is a significant laggard when it comes to other markets. I think our report tried to highlight that.

If you want a competitive and transparent market, you need to provide data. And this is what other markets do. And Ontario has taken an approach of not doing that. So we do highlight that throughout the report.

MR. PIETREWICZ: You do. Thank you for that. Moving on to Power Advisory's response to VECC 23.2. And you don't even have turn it up.

VECC asked Power Advisory about its calculations for water power spill and Power Advisory's answer was that this is Power Advisory's working assumption on the marginal cost of hydro. As noted extensively throughout our evidence, the lack of data related to hourly curtailment amounts and costs, et cetera, et cetera, undermines transparency and the true costs of curtailment in Ontario.

Again, this is another example, would you agree, that Power Advisory had to work in face of data gaps?

MR. LUSNEY: I think, as mentioned before we developed -- we had multiple objectives in what we were trying to do. One is that we wanted to prepare our evidence to provide, you know, a simplistic and transparent methodology and approach to inform the panel an understanding of what a higher ETS or lower ETS might have on broad impacts to Ontario ratepayers.

So while I can generally agree that it's yes, we're flying a little blind and therefore we had to take the basic manoeuvres, for lack of a better quote, we still stand by our evidence, that, you know, this -- given what's been available and given the approach and our understanding of the market is, you know, valuable for the panel to consider, and that we would be more accurate with more information. And we may come at it from a different approach to be able to provide more insight and analysis.

So that is why we kind of raise that, you know, there is a lot of very good questions from intervenors that we would be much happier to answer, but we can't because of what -- where we stood.

MR. YAUCH: I'm gong to add to that. I don't think there is that much uncertainty in the congestion rent numbers, frankly, at all. I think the increased ETS, as you see, when HOEP goes up congestion rents decline. I don't view the band of uncertainty there quite high.

Spilling and curtailment, because there's a lot of operational data there, maybe that is a little different, but I think if you add in a five dollar -- essentially a five dollar transactional cost to hydro and you pushed it from 14 to almost 20 dollars, you're bumping up very close to marginal cost of gas generators in neighbouring jurisdictions, and I also think there would be a big impact in hydro curtailment, and if anything we're probably underselling it.

MR. PIETREWICZ: Thank you. I will skip over. I mean, I think you made the point very well that you have experienced some data gaps or challenges, but you have done -- you have asked to work around them in a way that I think you're saying that you stand behind them in terms of the directional result.

Fair enough. In the spirit of getting through this I will skip a bunch of questions, but I do want to ask you about one more data-related question.

The Power Advisory says in its response to OEB Staff 23 that congestion rents and exports are partly the result of conditions in neighbouring markets, not just SBG in Ontario, and that is the point that I want to make, that, you know, this is a highly interconnected, dynamic type of machine and system that we're talking about, and I think you mentioned earlier today in your discussion with some others that what's going on in neighbouring markets is also relevant to your analysis.

Would you agree with that?

MR. YAUCH: Yes. And it hasn't been brought up today, but in SEC 11, I believe it is, we provided some congestion rents on the Quebec inter-tie this winter. They were quite extreme, and Ontario was not an SBG in any way, shape, or form, and as far as I know -- you can't quote me on this, but I'm pretty sure those are record congestion rents for Quebec at that time.

So it can occur when we're not an SBG, because there is a huge component that happened -- whatever is happening in the neighbouring market will have a big impact on congestion rents here.

MR. PIETREWICZ: Great. Thank you. So you agree, yes, that it is just not domestic factors but factors around us that impact the congestion rents.

MR. YAUCH: Yes.

MR. PIETREWICZ: And earlier we talked a little bit about, and you mentioned it more extensively in your evidence, that -- you know, the data gaps with respect to Ontario data.

My question to you is that, did you have the same sort of data issues when you considered the conditions in neighbouring markets in your analysis?

MR. YAUCH: No, largely because we weren't looking at spill and curtailment in neighbouring jurisdictions, but it is not really prevalent there. So those sort of data gaps that we were facing here, we didn't -- they're not really there in neighbouring jurisdictions now.

MR. PIETREWICZ: Are you saying that you didn't consider neighbouring jurisdictions when estimating the impact of changing ETS on exports and ICP revenues and impacts on Ontario ratepayers? Are you saying --

MR. YAUCH: No, because we were -- we're backwards-looking, right? So the supply mix in neighbouring jurisdictions was the supply mix. And so we just looked at the price opportunity that would have changed as a result of the change in ETS.

MR. PIETREWICZ: Of course. Thank you. And so, so far we have been talking about, you know, this analysis on the historical basis, which is difficult enough.

Would you agree that, looking forward, trying to forecast outcomes would be just as difficult, if not more difficult?

MR. LUSNEY: Yes. And I think that we have touched on this a few times. The future is inherently uncertain, and any forecast has to take a certain objective into mind, that you are looking at, and I think one that we as a firm who performs, you know, wholesale price forecasts for a large number of clients and entities in the Ontario market and in other markets, you know, one thing, for example, that we provide is we can give a volatility forecast or we can give an annual supply demand balance and investment opportunity forecast.

They're very different, and you can't do the same at the same time, just given how models and assumptions work out.

The other one related to that that I think is very important for all intervenors and the panel to consider is exports as a system is kind of your last resort before you start potentially curtailing and paying for aspects, that it is a release valve for the system in conditions, and we note in one of the answers that, you know, the expectation of demand growth is you're not going to face issues, but the reality is, is you are going to have unforeseen events.

And the province, along with the rest of the world, dealt with an unforeseen event with respect to a pandemic [audio dropout] is domestic and external demand. About a decade before that we had a financial crisis, which, we've never really returned to demand levels at that capability.

So when looking at forecasts you are trying to take a view for the system. The only thing that you know for sure is that you will not be right. You will likely have some wrong. So when you do look forward I agree with your comment that it will become more difficult, and there is a lot more nuances that you will not be able to anticipate.

MR. PIETREWICZ: Thank you. And I have only three or so questions left, so I will just kind of cluster the questions then.

Looking forward, I mean, the IESO spoke a little bit yesterday, and VECC 18 asked the IESO to -- about changes in TRCA disbursement methodology, and the IESO said that there would be a behaviour change as a result of the change in the disbursement methodology.

My question to you is, do you agree that there will be a change in behaviour of market participants as a result of changes in the disbursement methodology, and do you know what that change will be?

MR. YAUCH: I am not convinced there will be a significant change. TRCA disbursements happen six months or annually.

When you are making an hourly trade based on prices, let's say in New York and Ontario, I find it a bit of a stretch to think that you are doing your bid based on a potential of some payment from this account.

So I think maybe at a very high level there would be some impact, but I don't think it would be in any way or shape significant.

MR. PIETREWICZ: Moving on to SEC -- this is an interrogatory from SEC to the IESO in the first round. I just want to cite it for context, SEC 8, in the first round of interrogatories. It's the IESO about the market renewal and implications of that looking forward, how things like congestion pricing, export volumes, prices, transmission rates [audio dropout] about market renewal program and what is up with that, what impact -- implications will have.

And IESO said that the day-ahead market will mean some changes for the ICP, and they said -- I think this is a quote -- that:

> "Fundamentally inter-tie flows will still be driven by underlying temporal changes or differences between jurisdictions, but there will be some technical changes that will impact inter-tie pricing and flows."

And later on they say that:

> "The single scheduled market will produce locational prices more reflective of conditions which can impact the level of congestion at inter-tie loads."

And so my question to you is, do you agree with the IESO that under-market renewal, technical changes, will impact inter-tie pricing and flows?

MR. YAUCH: Yes. At a high level, yes.

MR. PIETREWICZ: And do you also think that there might be some behavioural changes? For example, do we expect that there might be different results than in the past during the transition of market renewal as participants figure things out?

MR. YAUCH: Potentially. Not to belabour the point -- I will give one example -- that right now, like, IESO, for example, has a day-ahead market, and you may have a position in the day-ahead market, and you settle it in real time in Ontario, and it may be your forecast real-time prices may have been off. In the future you can tie a day-ahead with a day-ahead, so that might change.

So behaviour, but ultimately the underlying economic arbitrage is what's going to drive the trade.

MR. PIETREWICZ: Right. Okay. So when we talk a little bit about behaviour changes and market renewal, I want to talk to you very quickly and wrap it up, about technological changes.

OEB Staff 23E to Power Advisory. It's OEB Staff 23E. We asked you about the potential of electricity storage, right, in helping to mitigate SBG.

And this was asked in the context of SBG as a factor of congestion repayments and [audio dropout].

And in your response you fairly said that you were not retained to analyze the future world of storage [audio dropout].

So my basic question to you is, in your opinion, could a technology like storage have an impact on SBG in Ontario in the future, and do you know to what extent it will?

MR. LUSNEY: I think at a high level, different technologies, different changes in consumer behaviour, demand load shape, supply mixes, all of this will change, you know, the real time and seasonal balance between supply and demand.

I think you know, it may be helpful. It may not be helpful I think with anything and as part of, you know, any regulatory framework of which you would include electricity market design, regulatory process, transaction, consumption, that will influence how those market participants and those technologies play.

So I think part of the reason why our answer was, you know, we didn't analyze it because to analyze it you have to kind of set out a framework that you are going to look at it and what it is specifically you are trying to answer.

MR. PIETREWICZ: Sure, sure. Fair enough. And we are talking about the future here, whereas your analysis was past looking. Fair enough.

My final question also relates to technology and technological change in the future and how it might change results in the future if you were to do this five years from now or ten years from now, compared if you did to today based on the previous five years.

This is kind of a moving target. It is part of the late breaking news we heard yesterday. Part 7A to the IESO, this is a question that Mr. Pattani asked the IESO in the first round of interrogatories.

He references the December 2021 planning outlook and he mentioned that at that time, the Ministry of Energy asked the IESO to enter into contract negotiations regarding a 1,000 megawatt cable that is an underwater transmission line between Ontario and the United States.

And Mr. Pattani asked about potential implications on congestion rents, and the IESO said that, look, the ICP depends on many factors, including constantly changing market conditions, competition, supply outages, weather. As a result, ICP collection is variable and hard to predict than the fixed charge like the ETS.

My last couple of questions to you is that, do you agree that when we're talking about import and export flows, something like a brand new 1,000 megawatt inter-tie could change things a little?

MR. YAUCH: Yes. And I am just going to reiterate because we do a lot of modelling and market simulation models, imports and exports are notoriously the trickiest thing to pin down. You need multiple forecasts and you need multiple demand forecasts, and you need to try to figure out what the transaction cost is between the two is and where the sync is and where the source, so they are inherently more complicated than other aspects of the grid.

MR. PIETREWICZ: I agree and understood. So a new 1,000 megawatt tie on top of the ones that we already have, you think if that were incorporated in an analysis, it might lead to different results, everything else being equal?

MR. YAUCH: Yes. I don't want to belabour the point, but Ontario is facing a future that is very uncertain. The IESO is procuring thousands of megawatts. It hasn't done that for a long time. We don't know what those megawatts are, we don't know what the marginal cost is, we don't know how they're going to be committed.

So the future, even with or without WECC, is probably more of a question mark we have seen for quite a while in the province. So I think the future is more uncertain than it was let's say three or four years ago.

MR. PIETREWICZ: Thank you. You can confirm your analysis did not include a brand new 1,000 cable between Ontario and the United States, right?

MR. YAUCH: No. It is historical.

MR. PIETREWICZ: And that is potentially in the future. So I think those are my questions. Thank you very much, panel. It was a pleasure.

MR. YAUCH: Thank you.

MR. RUBENSTEIN: Can I ask one follow up?

MR. SIDLOFSKY: Go ahead, Mr. Rubenstein.

MR. RUBENSTEIN: Mr. Yauch, your last statement, or one of your last statements about the future being uncertain and we're in a unique -- or at least compared to -- I think you would agree that at least compared to the last number of years, we're entering into a very unique time and a lot more uncertainty. I think that is fair to say.

MR. YAUCH: Yes.

MR. RUBENSTEIN: I just want to understand. Is it in your view then that the implications of that would, with respect to changing the ETS rate, is that the OEB should be more likely than not to maintain a more status quo ETS rate because we don't know the implications of higher ETS rates or lower ETS rates? Would you agree with that?

MR. YAUCH: We tried to isolate the impact of changing it on a system.

Now, with the system changing, you're adding uncertainty on top of uncertainty. So kind of how that plays out is, I think, a risk both to the OEB and parties in this proceeding.

We didn't look at it on a forecast basis. I know we said this many times, but we do think that it is not clear what the future is. So changing the ETS is going to add to, you know, more uncertainty.

But our evidence show that a lower ETS allows for greater exports, which has a system-wide benefit. And increasing it can actually result in operational and financial costs that can make Ontario ratepayers worse off.

MR. RUBENSTEIN: But future uncertainty makes both of those things uncertain on either end, higher or lower.

MR. YAUCH: It kind of adds to the bucket of uncertainty. I think Mr. Pietrewicz was asking, you know, of all these sort of river analysis high and low, it is going to add to it.

MR. RUBENSTEIN: Okay, thank you very much.

MR. SIDLOFSKY: Thanks, Mr. Rubenstein. I am not used to saying this, but we are way ahead of schedule. And we're actually coming up on the time that we were going to be breaking for lunch.

So let's do that. It is 12:25. Let's come back at 1:15 and at that point, Mr. Myers, you will be introducing the Elenchus panel. Correct?

MR. MYERS: That's correct.

MR. SIDLOFSKY: Okay. So good. We are adjourned until 1:15. We will see you then. Thanks very much.

--- Luncheon recess taken at 12:24 p.m.

--- On resuming at 1:15 p.m.

MR. SIDLOFSKY: Good afternoon. We are back with our last panel of the technical conference, the Elenchus panel.

Perhaps we can start with Mr. Myers introducing the Elenchus panel, and then we will move on to Mr. Vellone for APPrO.

MR. MYERS: Thanks very much. So our panel from Elenchus is consisting of Andrew Blair. He is a research analyst with Elenchus. Our original intention was to also include John Todd. Unfortunately, John Todd is dealing with a bout of COVID and is not feeling up to participating today.

So it is just a bit of, I guess a heads-up that there may be questions that Andrew is unable to respond to, and he may have to take additional undertakings than we otherwise may have had to do, but Andrew was one of the authors that participated in the preparation of the report, and so he is well-prepared to respond to your questions.

So with that, I turn it over to you, John. Thanks.

ELENCHUS - PANEL 3

Andrew Blair

EXAMINATION BY MR. VELLONE:

MR. VELLONE: Thanks, Mr. Myers. Understanding the qualification, I hope Mr. Todd is doing well.

Allow me to introduce myself. My name is John Vellone, and I'm counsel for the Association of Power Producers of Ontario in this case, Mr. Blair.

And to get us started I was wondering if we could pull up the response to VECC IR number 33, which I think is included at Exhibit I, tab 5, schedule 33. And there is quite a preamble in this question before they get to the question, but the preamble, I think, is just an -- it's an extract of the Elenchus study, the evidence you provided, providing a description of how the export rates are set in the Alberta market. Do you agree with that?

MR. BLAIR: Yes.

MR. VELLONE: Yes. And just to focus in briefly in the preamble, you note in your evidence that the AESO applies a 20 percent weighting to capacity-related bulk and network system costs for the purposes of designing its export rate, and then I think the second paragraph just provides a quotation as to the rationale for that weighting. Is that right?

MR. BLAIR: That's right.

MR. VELLONE: And my reading of your response really to part 33(2), the response, and really that last paragraph in there at lines 23 to 26, is that Elenchus is not proposing a similar methodology to what was done in Alberta, and you go on to explain why. You are designing an export-specific tariff, and that is not what they did there. Is that right?

MR. BLAIR: We use cost-allocation methodology, and the exact rate isn't necessarily underpinned by cost-allocation methodology.

MR. VELLONE: In Alberta, you mean?

MR. BLAIR: In Alberta, yes.

MR. VELLONE: Okay. My understanding of the methodology that you did use, you explored a few different scenarios to allocate shared network cost to exporters, I think 50 percent and 80 percent. Have I got that right?

MR. BLAIR: That's right.

MR. VELLONE: Is it possible to run a scenario where you also explore the impact on the ETS rate of allocating 20 percent of shared network costs to exporters?

MR. BLAIR: Yes. That's possible.

MR. VELLONE: Could I get an undertaking to do that?

MR. BLAIR: Yes.

MR. SIDLOFSKY: We will make that JT2.3.

UNDERTAKING NO. JT2.3: ELENCHUS TO RUN A SCENARIO TO EXPLORE THE IMPACT ON THE ETS RATE OF ALLOCATING 20 PERCENT OF SHARED NETWORK COSTS TO EXPORTERS.

MR. VELLONE: Thank you very much. My next question -- I think we might as well go to the response to APPrO interrogatory 1A. It is tab 9, schedule 1.

And in the response to this interrogatory also later, I think, in part L, Elenchus says you did not review things like ICP or uplifts or avoided system costs and other benefits as a revenue offset for providing transmission assets used for export service. Did I get that right? Those are -- I was asking you to include these other benefits as a potential revenue offset. And your answer, if I am reading it correctly, is it is not a revenue offset, so we didn't include it?

MR. BLAIR: That's right. It is not a revenue offset to Hydro One's revenue requirement, or any other transmitter.

MR. VELLONE: So I'm going to attempt to follow up, and I think we hit the same issue again in APPrO 2. We don't have to go there, but basically it is the same exchange. I am going to follow up on this request, and I am going to start with an apology, which is that the interrogatory questions -- in the interrogatory were questions. I proposed a specific type of solution. I proposed using revenue offsets as some way to link these other benefits back to the cost-allocation methodology.

That trying to skip to the solution is probably -- that's my fault. I probably shouldn't have done that.

So let me try something a little bit broader and see what you think.

The OEB panel in this proceeding, the commissioners, are going to be considering not only the Elenchus cost allocation study but also the IESO evidence that was filed, the Power Advisory evidence that was filed, and in your view, in your expert opinion, do you think the commissioners should be considering these other system benefits associated with exports, such as those outlined in the IESO evidence or the Power Advisory evidence in addition to the cost-allocation methodology and, if so, like, how should they right the square, I guess is my -- 1) is, should they be considering it, and 2), do you have any ideas on how they can do it?

MR. BLAIR: Yes, they should consider those other factors, those other policy decisions for setting the ETS rate. But in terms of the cost-allocation methodology, I don't think it is appropriate to include these other factors that aren't exactly related to the Hydro One transmission revenue requirement or other transmitter revenue requirements within the cost-allocation model.

So the consideration of those is sort of outside of the realm of cost allocation.

MR. VELLONE: I guess -- I understand your response, because I think the issue is Hydro One doesn't collect any of those revenues for the purposes of the cost-allocation study you are doing, right?

MR. BLAIR: Right.

MR. VELLONE: Would your response potentially change if the IESO chose a different methodology to -- and I am going to narrow my scope. This is asking about a lot of benefits. I am going to narrow the scope of my questions just down to inter-tie congestion pricing specifically for the purposes of our follow-up.

And I guess, would your response change if the IESO, instead of deciding to rebate the TR clearing account out to all customers, instead elected to take the congestion portion of that account and pay it to Hydro One, in the same way that it remits to Hydro One the ETS revenues it collects?

MR. BLAIR: Yes. If it was part of the revenue requirement, part of other revenues, for the purpose of setting the rates revenue requirement, then we would include it in the model.

MR. VELLONE: Okay. And so I guess what I am trying to do is, I am trying to get to, is there a creative way where from a cost-allocation approach we can get ICP considered? And it sounds to me like if the IESO changed how they disbursed the monies they collect from those congestion pricing, then you would by necessity have to take it into account in your cost-allocation study, right?

MR. BLAIR: That's right.

MR. MYERS: May I ask one clarifying question on that, please?

MR. VELLONE: Yes, go ahead.

MR. MYERS: It is Jonathan Myers from Torys. I think you have been asking about the receipt of those amounts as an external revenue source for Hydro One. I am wondering if Mr. Blair could comment on whether that's, you know, the full story.

Even if those amounts are not derived on the underlying costs of assets within Hydro One, do they still flow in the cost allocation model if they're just received on the revenue side, but they're not part of the build up of the revenue requirement?

MR. BLAIR: If they were another revenue for Hydro One transmission, then for the purpose of setting allocated costs that consider other allocated revenues as well, to have a total full cost allocation model, it would be included as another line item.

We would probably consider it separately from other external revenues and consider it on its own basis as a line item.

MR. MYERS: Thanks for that clarification.

UNKNOWN SPEAKER: I see you are muted.

MR. VELLONE: Zoom also told me the same thing. If I could turn up the response to -- I will end up at a request for an undertaking and you can take it or not. Actually, why don't we try that now.

Would you be able to undertake to model on a hypothetical basis what the impact of including congestion rents on the cost allocation study you performed would be? And for the purposes of pulling the data, I would probably point you to attachment 1 to Hydro One's response to Staff 1, which is where IESO provided a whole bunch of data, and I will allow you to parse it and figure out what is the appropriate inputs to use.

But I am trying to get as close to apples to apples as I can with regards to amount paid by exporters there and amounts paid to exporters via ETS rate.

Would you be able to undertake to do that on that assumption basis? I just want to see what happens.

MR. MYERS: If I can jump in for a second, recognizing you are taking up a very short turnaround on this proceeding, I think they're due on Thursday of next week.

So I will leave it to Mr. Blair to respond, but there is not a lot of time and this seems like it may be an onerous request.

So it may be something we need to take back and if it is able to be done, then we can do it. If we're not able to do it, then we would have to explain why.

MR. BLAIR: My hesitation is it would be simple to plug in the total number. But to determine how those other revenues should be allocated amongst domestic and export rate classes would take some thought. It is not just recreating a model is, it also determining the methodology for that. And I'm not sure we can undertake to develop a methodology in the time frame.

MR. VELLONE: I will volunteer one. One of the tables that the IESO provides in that attachment I pointed you to shows the allocation as between imports and exports. It gives you historical data.

MR. BLAIR: Okay. So specifically assuming that it is the same allocation that the IESO has been allocating?

MR. VELLONE: It is kind of almost based on historical numbers, yes. The IESO gives you historical allocations over X number of years. I think you can make assumptions. Feel free to make simplifying assumptions if it speeds things up. I am not asking for perfection, I am looking for a sense of what the impacts are.

MR. BLAIR: We can undertake to do that, recognizing that we are following the IESO's methodology for allocating costs rather than our own proposal.

MR. SIDLOFSKY: I will give that undertaking number JT2.4.

UNDERTAKING NO. JT2.4: ELENCHUS TO MODEL THE IMPACTS ON ITS COST ALLOCATION STUDY FILED IN THIS PROCEEDING OF CHANGE THAT WOULD RESULT IN CONGESTION RENTS BEING REIMBURSED FROM THE IESO DIRECTLY TO HYDRO ONE, IN THE SAME WAY THAT THE ETS RATES ARE COLLECTED BY THE IESO AND REMITTED TO HYDRO ONE; TO MODEL THE IMPACT OF THAT ON THE STUDY.

MR. SIDLOFSKY: But I would ask that you give a concise statement of that undertaking, just for the record.

MR. VELLONE: I will volunteer to do that. The undertaking would be to model the impacts on your Elenchus cost allocation study filed in this proceeding of change that would result in congestion rents being reimbursed from the IESO directly to Hydro One, in the same way that the ETS rates are collected by the IESO and remitted to Hydro One, to model the impact of that on your study.

MR. SIDLOFSKY: Mr. Blair, does that accurately describe what you are prepared to do?

MR. BLAIR: Yes.

MR. SIDLOFSKY: Okay. Thank you.

MR. RUBENSTEIN: I don't mean to interrupt. Mr.

Vellone, you referenced a table in the IESO's evidence and I just didn't catch the table you referenced.

MR. BLAIR: It's tables in attachments.

MR. RUBENSTEIN: Which table was it? As I understood it, you had asked the assumption against the allocation between domestic and exports that you essentially -- I understood you were pointing to a table and said use this. I was unclear, I didn't catch what exactly you wanted him to do so I can follow along here.

MR. VELLONE: You didn't catch it because I didn't say it. And now I am skimming through the tables to find the right one.

MR. BLAIR: The total congestion rents to include that as another revenue and based on historic disbursements, that is how it would be allocated in the model.

MR. VELLONE: Yes. Table 11 has import congestion rents by year for 2017-2021. And then elsewhere in here you have total congestion rents per year. So I think if you do a simple subtraction.

MR. BLAIR: Yes. I believe the numbers are in here, and if simple assumptions are necessary, we will make them and describe them in the response.

MR. VELLONE: Is that clear enough for you, Mr. Rubenstein?

MR. RUBENSTEIN: Only just -- I am not clear what you are asking. What is the split based on? Just because I may have a follow up, and I want to make sure that I -- or I may not have a follow up.

MR. VELLONE: To be honest, I am putting myself a bit in Mr. Blair's analytic capabilities and allowing him to make some judgments on how to do it properly instead of trying to be prescriptive. Should I move on?

Hearing nothing. Pull up the response to Staff 34. Tab 1, schedule 34. Maybe just go down to the responses there. Have you had an opportunity -- I assume as part of your preparation, you have taken a chance to read through the evidence including responses from the IESO to these questions?

MR. BLAIR: Yes. I have read through them.

MR. VELLONE: I will give you a second -- most of my follow up questions are going to relate to part B of the response. I will give you a moment to read through it. Let me know when you are ready.

MR. BLAIR: Okay. Ready.

MR. VELLONE: Would you agree with the IESO, with the statement they're making in the first sentence there that both the ETS rate and ICP are intended to offset inter-tie infrastructure costs for Ontario consumers -- generally agree with that?

MR. BLAIR: Generally agree with that, yes.

MR. VELLONE: Okay. And then the next one is harder to pinpoint, but it is in the middle of the paragraph somewhere.

Would you agree with the IESO's description that the ICP is really a market mechanism that prices transmission capacity at the inter-tie?

MR. BLAIR: Yes, I would agree with that.

MR. VELLONE: So I am involved in this proceeding largely on behalf of exporters, and the concern I really land on is the ultimate effect of this, from my perspective, is that exporters are paying twice for the same thing: the use of the transmission system in Ontario. They're paying once via the ETS rate, whatever that happens to be and however it is set, and again via the ICP market mechanism.

Would you agree that that is a fair characterization of the odd situation we found ourselves in here?

MR. BLAIR: No, I would say that the inter-tie congestion pricing is paid for capacity on inter-ties, whereas the ETS is for use of the shared transmission system for the province.

MR. VELLONE: Including inter-ties. Right? You do allocate costs associated with inter-ties?

MR. BLAIR: Right, yes.

MR. VELLONE: And then we pay -- then exporters pay again for the use of those inter-ties through the ICP. Is that correct?

MR. BLAIR: The revenues from the ICP don't necessarily offset the inter-tie costs exactly.

MR. VELLONE: For sure. We've been there. I think this statement from the IESO is intended to offset, and I think I had to make you make an assumption to get you to put it into the cost allocation model, so I am not trying to suggest that it is currently doing that. But from an intention point of view, right, these two things are intended to fund the same infrastructure, and exporters are basically paying twice for the use of the inter-ties, once via your cost-allocation model, 12CP allocator, second time via this market mechanism.

MR. BLAIR: Yes, they are paying twice, and it is done with the same infrastructure, but the capacity of the infrastructure at the inter-ties -- it is sort of a separate thing they're paying for there, rather than just use of the system to get them there.

MR. VELLONE: That's a fair qualification.

Are you aware of any other users of Ontario's transmission system that are treated in a similar manner, they're being asked to pay twice for the use of the assets?

MR. MYERS: Sorry, if I can just interrupt for a second. I don't think Mr. Blair agreed that exporters are paying twice for the use of the assets, which you implied in your question.

MR. VELLONE: Okay. So let me go back and clarify, because I thought I did hear him say yes.

MR. MYERS: It was a yes with a qualification, not an unqualified yes.

MR. VELLONE: Are you aware of any other users of the Ontario transmission system that are being asked to pay twice, acknowledging the qualification you just gave me on your answer previously?

MR. BLAIR: I am not too familiar with the import market, but if there are imports that are -- inter-tie congestion pricing on imports, and also there would be the network, then customers are paying twice for that.

MR. VELLONE: Yeah. Those are load customers. Okay, yes, that's fair. Any others?

MR. BLAIR: No, I think that is in terms of transmission. But paying for capacity and paying for use of the -- use of the system is not uncommon more generally.

MR. VELLONE: I may be able to shorten my questions. Just give me a second. I'm just going to work through here.

I guess, pull up the response to Energy Probe 6B. Tab 2, schedule 6. So in the undertaking I asked you to consider, I focused specifically on making an assumption that Hydro One receives congestion rents as another revenue potential input.

MR. BLAIR: Right.

MR. VELLONE: And I think, for the sake of fleshing out the entirety of the evidentiary record, I would like to ask you to do the same thing, but this time with the entire balance of the TR clearing account.

And the reason I am asking that is because my understanding at least in New York is that they do take into account the financial exchange with TRs, as well as congestion, when setting an export tariff in that jurisdiction. So I think it would be informative to see what happens if you do the whole thing, as well as just the congestion rent component.

Would you be willing to do that, on the same -- exact same understanding as we had originally, which is best efforts, acknowledging the limited time frames we have, if there is needs to make assumptions you can point back to the IESO data?

I do think this response points to table 5, which shows an explicit split between TRCA disbursement between load and exports, so you can point to that. But would you be willing to make a similar undertaking with that broader request?

MR. BLAIR: Yes, we would.

MR. HARPER: Excuse me --

MR. MYERS: Can I just get a clarification on that, please. Sorry, Bill. Maybe I might be dealing with the same thing, but you can jump in after.

When you say "the entire thing", are you excluding the portion of the TRCA that goes to exporters, and are you excluding the threshold amount that I believe is retained within that account?

MR. VELLONE: I would be in Mr. Blair's hands as to how to properly account.

I am not going to be prescriptive, Mr. Myers. I don't want to tell him how to do his -- I am asking him to do the best he can in the limited time he has available, and those things you said seem reasonable to me, to be honest, if that is how he came back, but I am not trying to be prescriptive on how he does it. I would like the expert to make his own decisions on that stuff.

MR. BLAIR: It says the amounts disbursed from the clearing accounts.

MR. VELLONE: Yes.

MR. BLAIR: Recognizing there is that amount withheld.

MR. VELLONE: Yes.

MR. SIDLOFSKY: And sorry to interrupt, but could I just get a concise statement of that undertaking, please?

MR. MYERS: Maybe before that, Bill, did you have any further clarification?

MR. HARPER: I wanted to ask, because my understanding was the second undertaking the distinction was to include in that all the monies that were cleared out of the account, including those that were paid to transmission rights-holders. Am I correct, Mr. Vellone?

MR. VELLONE: Yes. The first undertaking was in respect of congestion rents only.

MR. HARPER: Right.

MR. VELLONE: The second one is in respect of this specific account.

MR. HARPER: Right. And then I guess the point I was going to raise, which I think adds a complication to it, which I am not too sure if Mr. Blair can address on the basis of the information on the record, is that we heard from the IESO that a portion of those rights are cleared not to exporters but to financial -- basically, people are doing this for a financial transaction and therefore would not be included either as domestic customers or export customers within the context. You are almost introducing a third class of customers here.

I'm just -- I don't know what information we have on the record on that, whether that's -- I just want to flag that going forward, if you want to actually go forward and think about this second undertaking. That was all.

MR. VELLONE: Thank you, Bill. Yes, I have similar reluctance to mesh transmission rates with exporters, because they're not -- it is not a one-to-one concept as clearly as the congestion rents, and you can look at the portion paid by import importers and exporters.

But I am conscious that they do do that in New York, and so I think it would be informative for the panel to see how it shakes out here as well. That is really the reason I am asking.

With that can I attempt the summary, Mr. Sidlofsky?

MR. SIDLOFSKY: I am not sure. Mr. Rubenstein has popped up here.

MR. RUBENSTEIN: Better you summarize what you think it is first.

MR. VELLONE: Certainly. It is to model the impacts on the Elenchus cost allocation study of an assumed change that would have the balances of the transmission rights clearing account remitted directly to Hydro One, as opposed to just disbursed to the benefit of ratepayers the way it currently is.

MR. SIDLOFSKY: Mr. Rubenstein?

MR. RUBENSTEIN: I am not going to muddy anything up further.

MR. MYERS: Maybe just one small further

clarification. When you say disbursed to Hydro One, you mean to Hydro One Transmission?

MR. VELLONE: Yes.

MR. MYERS: Like ETS rates, and not Hydro One Distribution?

MR. VELLONE: Correct. That is correct, Mr. Myers.

MR. SIDLOFSKY: Okay. Not seeing anyone coming in with questions. Mr. Vellone, did you want to continue?

MR. VELLONE: Have we got that one marked.

MR. SIDLOFSKY: That was JT2.5.

MR. VELLONE: Thanks.

UNDERTAKING NO. JT2.5: ELENCHUS TO MODEL THE IMPACTS ON THE ELENCHUS COST ALLOCATION STUDY OF AN ASSUMED CHANGE THAT WOULD HAVE THE BALANCES OF THE TRANSMISSION RIGHTS CLEARING ACCOUNT REMITTED DIRECTLY TO HYDRO ONE TRANSMISSION, AS OPPOSED TO JUST DISBURSED TO THE BENEFIT OF RATEPAYERS THE WAY IT CURRENTLY IS.

MR. VELLONE: I would like to continue with the response to APPrO 2A. So in this question, I had asked about Elenchus's professional opinion as to whether or not a recommended methodology to allocate costs would include no shared assets to exporters.

And in the preamble, I actually pointed back to your previous cost allocation study filed in EB-2015-0304.

And I didn't think -- I didn't think I was doing anything controversial to suggest that Elenchus previously recommended, as part of your overall cost-allocation methodology, that no shared asset network costs would be allocated to exporters.

I didn't think that was controversial. But I don't see that in your response.

MR. BLAIR: That's a fair characterization of that report.

MR. VELLONE: You actually cover it pretty clearly in section 6.3.2 of your current report. You basically say our previous report recommended that OM&A costs associated with shared network assets would be allocated, but that the net fixed asset -- but the net fixed asset allocator, but depreciation and return on capital and PILs would not. Is that right?

MR. BLAIR: That's right.

MR. VELLONE: And I have some stuff in the compendium, but maybe we don't even need to go there. Do you recall what the basis of that recommendation was previously? Why did Elenchus land on, from a strictly cost allocation point of view, why should we not allocate these costs to exporters.

MR. BLAIR: It is because the export class was treated as an interruptible class. So the general concept is the system was not built for interruptible customers. So they shouldn't pay the capacity-related costs of the system.

MR. VELLONE: So two things. One is the system is not built for them. And two is they also just don't receive the same level of service, they're interruptible? Did I get that right?

MR. BLAIR: That's right. Yes. They don't receive the same service, which is why they're allocated that portion of costs.

MR. VELLONE: And so my reading of the new Elenchus study is you received -- you reviewed the previous -- your client reviewed the previous OEB decision. The OEB decision said we want to explore allocating shared network asset costs to exporters. Please redo it, and come up with some options. So you basically re-did it and looked at a couple of options on how to do it, is that right?

MR. BLAIR: Yes, that's right.

MR. VELLONE: If that decision wasn't out there, your original recommendations would stand, that the best way to do this for the reasons you previously stated is, no shared asset network costs would be allocated to exporters except for the O&M costs?

MR. BLAIR: No. We would agree that a portion of shared network asset related costs should be allocated to the export class and the two -- the export class is defined is curtailable rather than interruptible, and looking for some information of exactly what the difference is. It is the curtailed and not curtailed in most hours, and even when they're curtailed, it is about -- in peak hours when they're curtailed it is only about 10 percent.

There are a couple of quotes in the report we got from the IESO to get a sense of the proportion of curtailments and they're largely not interrupted and do have fairly good access and increasing access to the shared system.

MR. VELLONE: Okay. On the second reason why you originally decided not to allocate on the planning -- it is not planned for them, the fixed costs aren't planned for them.

MR. BLAIR: It is not planned by them, but we also look at who is using the system, so the value derived from the system. And this is a concept that is used in other jurisdictions as well. Like in the Quebec report, no free service is a principle of cost allocation in Quebec and the FERC transmission cost allocation guidelines, the first one is that the benefit should be -- the costs should be roughly commensurate with benefits.

And sort of a signal from the OEB decision to look at the value also in addition to cost basis, and that is why we agree it makes sense to allocate asset related costs to the export class.

MR. VELLONE: So your opinion has evolved since that 2014 study. Is that a fair characterization?

MR. BLAIR: Yes. Our opinion has evolved and our view of the export class is part of that changing view.

MR. VELLONE: And I touched on this at the start, but I will come back to it again, I guess. In your view, should the OEB be considering the broader benefits associated with exporters, exports outlined in the IESO evidence and the Power Advisory evidence, we don't have to repeat it, when making a decision as to how much or whether to allocate shared network asset costs.

Do you think that is a fair consideration for the regulator?

MR. BLAIR: That is a fair consideration, definitely. We looked at one stream of it, which is allocated costs. But we understand there are other policy objectives and other considerations for the Board to look at.

MR. VELLONE: Okay. Mr. Sidlofsky, I have completed my questioning.

MR. SIDLOFSKY: Mr. Vellone, thanks very much.

MR. VELLONE: Thanks very much, Mr. Blair.

MR. BLAIR: Thank you.

MR. SIDLOFSKY: We are on to Mr. Rubenstein, Schools.

EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Thank you, Mr. Sidlofsky. Let me start off sort of with some of the questions and exchanges you just had with Mr. Vellone.

When Mr. Vellone was asking you about the ICP revenue was remitted to Hydro One Transmission and how would it be incorporated in your cost allocation model. I know there was a discussion about the methodology, but at a high level I took it -- you had other revenue and you would flow it into your model in some way. Is that a fair characterization?

MR. BLAIR: Yes. We would flow it in some way, that way we don't exactly know what we would propose for that.

MR. RUBENSTEIN: You agree with me if the IESO allocated costs, some set of costs to -- you know, and sent a bill to Hydro One transmission to pay some sort of costs, you would have included that as well in your cost allocation model. Similarly, you wouldn't know exactly how, but you would have to include that as well and that would tend to obviously increase costs that would be allocated to various customers, correct?

MR. BLAIR: That's right. In a full cost allocation model, we would want the costs allocated to match the revenue requirement exactly.

MR. RUBENSTEIN: All right. Mr. Vellone also asked you -- he took you to, I believe it was Staff 34b, which was actually asked to the IESO, but the IESO responded, and this was with respect to the purposes of ICP and ETS.

And I believe you agreed with him -- or you agreed with the IESO's response to the first sentence that both mechanisms are intended to offset inter-tie infrastructure costs to Ontario customers? Did I hear that correctly?

MR. BLAIR: You did hear that correctly, although, looking at it now, again, offset specifically inter-tie infrastructure costs, I don't agree with that.

MR. RUBENSTEIN: You don't agree with that?

MR. BLAIR: I missed the word "inter-tie infrastructure costs" there. For sure the ETS rate -- the costs that they're [audio dropout] the ETS rate aren't necessarily just the inter-tie costs.

MR. RUBENSTEIN: Okay, that's fair. But -- so the qualification is ETS rate is a broader aspect of infrastructure costs, correct?

MR. BLAIR: Right.

MR. RUBENSTEIN: But do you agree then that ICP revenue is intended to offset inter-tie infrastructure costs to Ontario customers? Do you agree with the IESO's position that that is the intention?

MR. BLAIR: If the IESO says that's the intention. I am not sure what the initial intention is. I can't really speak to the initial intention.

MR. RUBENSTEIN: Yes, well, that is what I wanted to clarify.

So I guess, using your independent view, do you believe the intention or do you know that the intention of ICP is to offset inter-tie infrastructure costs to Ontario customers?

MR. BLAIR: No.

MR. RUBENSTEIN: Okay. Am I correct, sort of a -- you would agree with me at a general level in Ontario cost-allocation purposes the OEB uses fully allocated costing?

MR. BLAIR: Yes.

MR. RUBENSTEIN: You know, there are takes, but how you allocate those costs and what is, you know, the specifics of what that mean, but you would agree with me at a high level that is fully allocated costing, correct?

MR. BLAIR: Yes.

MR. RUBENSTEIN: And many of the scenarios in your report are trying to get at that, how would you fully allocate infrastructure costs through transmission and domestic customers, correct?

MR. BLAIR: That's right. Export and domestic customers.

MR. RUBENSTEIN: Now, you were asked by Mr. Vellone with respect to the differences between your 2014 report, and one of the things that he raised, and I think you answered, was the idea about, that the system was not built for exporters. Do you remember your discussion with him about that?

MR. BLAIR: Yes.

MR. RUBENSTEIN: And I think you explained why in your view you should still allocate network costs, but I just want to discuss the issue of -- I just want to put that aside for a minute and ask you about your views about the system being built.

You would agree with me that the -- that different customers, an individual customer who connects to a distribution or transmission system in Ontario, even though the infrastructure was not built for them, is still allocated costs, because they use that system. Correct?

MR. BLAIR: That's right.

MR. RUBENSTEIN: Okay. Now, there was also some discussion with Mr. Vellone about the question about double payment, that exporters are double-paying for inter-tie infrastructure costs. Do you recall that?

MR. BLAIR: Yes.

MR. RUBENSTEIN: Now, you just agreed with me that you don't know the intention of inter-tie congestion pricing. So is it fair to say you don't know if there is double payment for inter-tie infrastructure costs? That exporters are paying twice for those costs?

MR. BLAIR: Yes. The specific phrasing of the costs for the -- to recover inter-tie -- inter-tie -- the costs of inter-ties in general.

MR. RUBENSTEIN: Let's just assume he is correct and that there is a double payment going on here for the purposes of the specific inter-tie costs.

Am I correct that the solution using your cost-allocation model would be to take out the specific inter-tie costs but keep the -- some amount of shared network costs, the common costs, essentially, all of the other costs? Conceptually.

MR. BLAIR: I don't think conceptually that is how we would do it. We could keep in the inter-tie costs.

MR. RUBENSTEIN: You would keep in the inter-tie costs?

MR. BLAIR: Yes. We would continue allocating -- I think we would continue allocating inter-tie costs the way it is described in the report, and the inter-tie congestion price would be allocated in some other way.

MR. RUBENSTEIN: But you could, I guess, also do the other way, right, correct? Remove those costs.

MR. BLAIR: You could start by directly allocating the costs of inter-ties -- a portion of the inter-tie congestion revenue, directly allocate whatever costs it is for inter-ties, directly allocate that as an offset so that what we are left with is allocated only to other assets.

MR. RUBENSTEIN: I would have looked at it that you would remove those costs because you would say, well, that is being dealt with -- inter-tie costs are being dealt with through ICP. Different mechanism. It is a market mechanism. So it is fully allocated costing, a little bit different. And then you would keep all the other costs which you would need to do using more traditional fully allocated costing.

Would that be an incorrect approach --

MR. BLAIR: But assuming --

MR. RUBENSTEIN: -- approach?

MR. BLAIR: -- assuming that all remains within Hydro One's revenue requirements, particularly the costs of inter-ties, we'd want to keep all the costs and revenues in the model. There would be a direct allocation, so functionally it would be almost the same as removing those costs, but it would be still within the model and still looking at the total rate-setting process.

MR. RUBENSTEIN: Okay. That is fair enough. That is fair enough.

Can I ask you to go now to SEC 12, please. Can I ask this question of Hydro One? But you are also -- Elenchus is also a common -- a common -- it's a joint response, so I would just like your opinion about this as well.

And so we asked about potential annual adjustments to the proposal in line between -- in 2024 to 2027 on a somewhat similar basis, that -- or -- well, much like Hydro One is proposing to do in its joint rate application, recognizing that there is an increase in the transmission costs.

And the joint response essentially says for the purposes of simplicity and stability Hydro One and Elenchus do not propose annual mechanistic adjustments to the ETS rates, and then it sort of provides some more explanation.

Do you see that?

MR. BLAIR: Yes.

MR. RUBENSTEIN: And you are aware at a general level of the joint rate application proposal?

MR. BLAIR: Yes.

MR. RUBENSTEIN: And you would agree with me that the revenue requirement for Hydro One transmission is -- their proposal is it will increase each year, 2023, and increase in 2024, and increase all the way to 2027. Correct?

MR. BLAIR: Yes.

MR. RUBENSTEIN: And so you would agree with me that if you -- and my understanding is that your model you are only using 2023 costs, correct?

MR. BLAIR: Correct.

MR. RUBENSTEIN: And so you would agree with me THAT if you maintain 2023 costs and the export rate remains the same, you don't take into account increases over those years, there is some level of cross-subsidization between exporters -- between domestic customers to exporters. Correct?

MR. BLAIR: There would be some degree. It would be -- this was from yesterday. It would be very small dollar amounts that would be cross-subsidized there, and just the stability of rates and simplicity, it was decided that that would be a larger consideration than that cross-subsidization issue.

MR. RUBENSTEIN: Okay. But you would agree with me that there would be some cross-subsidization.

MR. BLAIR: Yes.

MR. RUBENSTEIN: I take it from your response is, is it enough to do something about it?

MR. BLAIR: Right. Right, I think.

MR. RUBENSTEIN: Okay. Can I ask you to go to SEC 10B. So in part B we had asked you to update the report for two different things, and the second one being Hydro One's cost information as a result of the evidence update to be filed on March 31st, 2022 in EB-2021-0110.

And so for context, the -- at the time we filed the IRs we didn't know what the proposal would be for Hydro One.

And so in the response you said you don't need to update it because they're deferring the proposal in the joint rate application is the increases that arise out of that update are to be placed under their proposal based in a deferral account to be cleared at some future time.

Is that your understanding as well?

MR. BLAIR: Yes.

MR. RUBENSTEIN: And that -- and as I understand the way you -- you would agree with me that there would be an allocation -- if you -- one of your mechanisms or your methodology, if it is approved, that balance itself would be allocated in a future date, some of it to exporters, correct?

MR. BLAIR: Correct.

MR. RUBENSTEIN: Just so I am correct in understanding, your report proposes a set of methodologies. But I would presume that if all of the joint rate applications the Board does not approve the deferral mechanism or approves a different revenue requirement, you believe the correct approach would be to -- whichever methodology the Board may choose or may not choose in this proceeding -- would be to sort of flow through whatever those numbers are in that joint rate application, in that decision, correct?

MR. BLAIR: Yes.

MR. RUBENSTEIN: Could I ask you now to turn to Power Advisory's report. Can we go to page -- I don't know what page it is here. Could we go to page 13 of that report -- bear with me for a minute, I think I have the wrong page number.

Go to page 16 of that report. Now, as you may have seen in the report, Power Advisory provides some criticisms or critiques of your report. I just want to talk some of those through with you and ask for your response.

So the first is, if you will see beside paragraph 47, Power Advisory says:

> "First, the proposed approach does not align with cost causation principles. As Elenchus correctly notes in its evidence, Hydro One does not take exports into account when designing the

transmission system and the IESO does not factor exports into the reliability planning assessments. Simplistically, the investments by the IESO and Hydro One do not consider the unique needs, capabilities or requirements of exports. Using a cost allocation methodology without cost causality principles is wrong and should be dismissed."

I take it your view is you are using cost causalities principles in your proposed methodologies, correct?

MR. BLAIR: Yes, that's correct.

MR. RUBENSTEIN: I think -- we don't need to belabour the point, but much of the commentary you made with respect to Mr. Vellone would apply to this, correct, about you know, they're benefiting from the system so they should be allocated costs, correct?

MR. BLAIR: Correct.

MR. RUBENSTEIN: And then at paragraph 48, it says: "Second, and related to the first is the concept of shared network assets that assumes each user is afforded the same considerations. The assets are not shared and have been designed, constructed, and operated to meet the needs of Ontario ratepayer needs, not exporters. The simple justification that because the asset is used by exports when excess capacity is available is not reason enough to force shared rate-based costs, which are underpinned by the economic viability of the asset."

Can you provide your commentary on that?

MR. BLAIR: Yes. We would agree that there should be consideration to the fact that they have a lower priority, and our report lays out the scenarios sort of -- really a range of scenarios from full cost causality or full 100 percent CP allocation to some discount allocation.

It is really up to the Board to determine how much of that discount should be applied to the export class. It could be one of the three scenarios, or it could be another scenario.

MR. RUBENSTEIN: It could be higher than the 80 percent, correct, between 80 percent and 100 percent, it could be some lower, it could be some number in between, correct?

MR. BLAIR: Yes.

MR. RUBENSTEIN: The third is somewhat, I guess, also reflective of the pole attachment, which is the Board's comments in the pole attachment report.

I won't read it, I won't read it out loud. But do you have any comments with respect to their criticisms of using the principles that were applied to the pole attachment charges?

MR. BLAIR: No. I think the Board's decision in the 2019 proceeding directed or pointed out the pole attachment decision and spoke in a bit of detail about the aspects of that. And look looking at the full decision, I think that is reasonable to have one of the scenarios the Board would consider. The Board was sort of indicating they were looking in that direction of some sort of cost sharing and

I think the 50 percent hybrid -- it is really just 50 percent sort of a compromise based on that number, except that is what was used in the pole attachment case, so that would be a reasonable thing to consider as one of the options here.

MR. RUBENSTEIN: And then at paragraphs 51 and 51, I won't read this also, but I guess this is also, as I read it, Power Advisory is talking about the benefits of exports, and I take it that goes to your sort of broader comment that there are other considerations than sort of a pure fully allocated costing that the Board should consider.

MR. BLAIR: That's right. Those are the things that should be decided on the ratemaking side of it, but not cost allocation. Those aren't transmission costs that should be considered.

MR. RUBENSTEIN: And so, that is the comment I just want to focus in.

So in your view, you don't play that into the cost allocation model. You sort of take that into account when you are determining if -- it is a consideration outside of the model that the Board should consider when it makes a determination of the final amount. Is that a fair way to look at it?

MR. BLAIR: Yes. That's fair.

MR. RUBENSTEIN: Okay. Thank you very much, Mr. Blair.

MR. BLAIR: Thank you, Mr. Rubenstein.

MR. SIDLOFSKY: Thanks, Mr. Rubenstein. We are moving on to VECC, Mr. Harper.

EXAMINATION BY MR. HARPER:

MR. HARPER: Is my camera on? I don't see myself on the screen.

MR. SIDLOFSKY: I can see you.

MR. HARPER: There I am. Okay, fine. Good afternoon, Mr. Blair. My name is Bill Harper. I am a consultant for VECC in this proceeding.

Actually, I had a few follow up questions on Mr. Vellone's undertaking, but I think Mr. Rubenstein has covered off most of those, except one and I think it is an important issue to understand and that is that there was a discussion about plugging the ICP revenues into the cost allocation model, if the revenues were decided to go over to Hydro One Transmission.

And would you agree there is a number of other considerations or issues that would have to be taken into account if that was -- if that change in paradigm was to take place in terms much how the ICP revenues were treated.

I think of a couple of things like, you know. The transmission rates are based on a forecast revenue requirement. Correct?

MR. BLAIR: Correct.

MR. HARPER: So one would have to come up with forecast values for ICP revenues, if I am not mistaken.

MR. BLAIR: That's correct.

MR. HARPER: And also I think the Board often weighs in on the -- when it is looking at external revenues, it often weighs in on what is the appropriate level of those values and sometimes the costing behind those values. That might be issues that might come before the Board as well if these revenues were included in the transmission revenue requirement. Would that be a fair comment?

MR. BLAIR: That would be fair, yes.

MR. HARPER: Also actually you got into a debate with this with Mr. Rubenstein that I think one method has been suggested to you as to how to treat these within a cost allocation model. But would you agree that if a formal proposal was to come forward from yourselves and/or Hydro One as to a question of how those costs should be functionalised, classified, and allocated would be ripe issues for discussion and perhaps disagreement in a future proceeding?

MR. BLAIR: Yes, absolutely.

MR. HARPER: Okay. Fine. Thank you. That is all I wanted to clear up.

I think it will be easier given Mr. Rubenstein's questions, but can we turn to Hydro One's response to VECC 1.2?

If we look at paragraph 2 here, here Hydro One has expressed its views as to the fact what needs to be considered in setting an ETS rate, you may consider fairness, efficiency, revenue recovery.

Do you agree those are all factors that have to be considered when actually designing and setting the rate?

MR. BLAIR: Yes, I agree.

MR. HARPER: What is your view as to what is the role of the cost allocation study, like the study that you prepared plays in assisting with these considerations?

MR. BLAIR: I think it is gives a good cost basis to look at the ranges of what any rate would be based on any assumptions for what the cost-allocation methodology -- what the results are. It gives a cost basis, which is one important consideration, one consideration in setting ETS rates and setting rates in general.

MR. HARPER: Right. And maybe we can turn to your response to Staff 18C.

Here I think, you know, Staff pointed out that you had three different methodologies in your report and that here you are indicating that you recommend option number 1.

I would like to clarify. You are recommending that option number one be used as the appropriate option in a cost allocation methodology, or are you recommending that option number one, the result of that should be used to set the ETS rate?

MR. BLAIR: We would recommend option 1, based on cost causality, pretty much exclusively. There is other considerations for the Board to consider. We don't factor that in. We don't presume what the Board will -- their perspectives on those other issues.

MR. HARPER: Right. So this goes, I think, to the last question Mr. Rubenstein asked you, and that is that, you know, you've got your cost-allocation results and these other considerations will be considered in parallel with them as the Board makes up its final decision as to what the ETS rate would be.

MR. BLAIR: Yes.

MR. HARPER: Okay, fine. No, no, thank you, that is helpful.

Can we turn to, I think it's your initial evidence, attachment 1 to the joint submission, page 20. And here Elenchus states -- Okay. I will just wait until we get there.

MR. BLAIR: There is two page numbers. 20 on the top of the page or the bottom of the page?

MR. HARPER: I think it is the one where you're talking about the regional transmission operators. I'm sorry. When I made my notes I forget now which of the two I was --

MR. BLAIR: It is the 20 at the top of the page.

MR. HARPER: 20 at the top of the page. Right. Here you say:

> "States that all regional transmission organizations and independent system operators in the United States and most IESO and transmitters in Canada set open-access transmission tariffs in accordance with a number of different FERC orders and that Ontario and Alberta are the only exceptions."

So with that in mind, can we go now to Staff 20. And if we scroll down through Staff 20, I believe it is in some of the middle -- probably the next page, the second page of the responses. Here CRA sets out at a high level, I would say, how export transmission rates are determined under the OATT.

And I don't know if you'd had a chance to look at this already, but would you agree with -- at a high level with CRA's sort of indication as to how transmission rates are set under the FERC's OATT? And I guess --

MR. BLAIR: Yes. So you're looking at response F?

MR. HARPER: Yes. Mainly D and F is what we're looking at. D defines what costs went into it and F defines basically once you got those costs how the rate is determined.

MR. BLAIR: Yes. I can agree with F. I haven't looked at the details of the costs included for -- in response to D. In general, these look like these are the right costs, but I can't say --

MR. HARPER: And would you agree that, based on this description, one could characterize the OATT-derived rates as being cost-based?

MR. BLAIR: Yes.

MR. HARPER: Okay. Can we then turn to Staff -- your response to Staff 12B. And really it is the first paragraph, where Elenchus states:

> "Elenchus is not aware of any jurisdictions that use the methodologies proposed in the 2021 Elenchus report, as these jurisdictions do not explicitly consider cost allocation for the

purposes of setting domestic and export
transmission rates and generally do not have
export-specific rates."

First, my understanding is that these other jurisdictions do have export transmission tariffs, the OATT-type tariffs, and so I wanted to ask you what you meant when you say these jurisdictions generally do not have export-specific rates.

MR. BLAIR: The rates based on the OATT that I have reviewed -- I think they have the same export rate, but it is an export rate listed as the same rate as the domestic rate.

MR. HARPER: Okay. So when you --

MR. BLAIR: And many jurisdictions -- most jurisdictions I would say do not have any reference to exports at all.

MR. HARPER: Okay. So when you say specific you mean a rate that's specifically different from, as opposed to not having any export rate at all?

MR. BLAIR: Yes.

MR. HARPER: Okay, fine. And -- now, the first part of the paragraph says that rates in these jurisdictions don't explicitly consider cost allocation for purposes of setting, you know, export transmission rates.

Can I get your agreement that the OATT-derived export transmission rates are cost -- I think you said they're cost-based, and so what I was wondering, if you can maybe just explain your distinction between a cost-based rate and a cost-allocation-based rate, if I can put it that way, because you seem to agree that they're cost-based, but then you go on to say they're not based on cost allocation. So maybe if you could just give me your understanding of the distinction between those two, that would be useful.

MR. BLAIR: The distinction is that the costs aren't considered separately for each type of customer. There is a different amount of cost per megawatt-hour or whatever bill determinant. There is a different amount considered for each different rate. So if it's the same, there is no consideration of this group to be paying more than this group, then it is really not a cost-allocation exercise.

MR. HARPER: It is only a cost-allocation exercise at its simplest level. We divided everything up on the basis of megawatts or megawatt-hours, but no more refinement than that, I guess.

MR. BLAIR: Right. I wouldn't consider that cost allocation.

MR. HARPER: Okay. No. That's fair. And I think that those are all of my questions. Thank you very much.

MR. BLAIR: Thank you.

MR. SIDLOFSKY: Thanks very much, Mr. Harper.

It is 2:20. I am going to suggest that we continue on with Dr. Higgin for Energy Probe, unless panel or our reporter needs a break right now.

MR. BLAIR: I am okay to continue.

DR. HIGGIN: Thank you.

MR. SIDLOFSKY: I'll just check with our reporter as well.

THE REPORTER: Yes, if we could have a break after Dr. Higgin.

MR. SIDLOFSKY: That would be great. We'll do that. Thanks.

THE REPORTER: Thank you.

EXAMINATION BY DR. HIGGIN:

DR. HIGGIN: Thank you. Just to let you know, many of the questions have been answered, so my original estimate was 30 minutes. It is going to be more like ten minutes. There is very little left for me to do.

So good afternoon, Mr. Blair. Sorry your boss who used to be my boss way back is sick. Hope he will be feeling better soon.

MR. BLAIR: Thank you.

DR. HIGGIN: So I would like to just start by looking at your ETS cost allocation model. And to do that, I would suggest we pull up the spreadsheet HONI-05-24-04. And I would like to look at sheet 1, because I have very little to ask.

Okay. So as you would have heard yesterday, we discussed the fact that these costs that you have used, the revenue requirement and the rate base, are slightly different than the updated 2023 revenue requirement and rate base for Hydro One.

So you heard that exchange, I assume, right?

MR. BLAIR: Yes, I did.

DR. HIGGIN: Okay. So basically, we're going to proceed on the basis of your model, as you proposed here, and then we're going to just have a few questions about that.

So perhaps now we could move to Exhibit I, tab 1, schedule 4, and I am looking at page 3 here. And there you will see at the top -- I assume you are familiar with this. It is the revenue-requirement projection for Hydro One going forward to 2027. However, as we have already discussed, there will also be certain amounts that will be deferred. In other words, this base amount here does not reflect the amounts that are being deferred. Correct? That is your understanding?

MR. BLAIR: Yes, that's correct.

DR. HIGGIN: Okay. So I just want to get from you a feeling for the size of the change, A), to the revenue requirement and, B), to the rate base going forward.

My estimate is that it's quite material. Right? Would you agree that going from 1.8 to 2.2 in the revenue requirement and also that the assets going from 14.52 million to something like 16 million is quite a significant change? Would you agree?

MR. BLAIR: I would agree it is a material increase.

DR. HIGGIN: So then you know where I am going to ask is, how often should the cost allocation study be updated, given these changes to the revenue requirement and of course to the asset base? Do you have an opinion?

MR. BLAIR: Our opinion is that it would make sense to update the cost allocation model when Hydro One rebases, so once approximately every five years.

DR. HIGGIN: So in the interim, these material changes were going to be recorded and we're just going to go perhaps and look at this same exhibit, page 4, if we could flip to part F.

I will give you a minute to look at that, if you are not familiar with this proposal.

MR. BLAIR: I am familiar with this proposal, yes.

DR. HIGGIN: So what this says clearly is that during that period, the amounts that are -- the excess variance account will capture amounts that are different than the base year revenue requirement. Correct?

MR. BLAIR: Correct.

DR. HIGGIN: But it would not, or does it -- I am going to ask you the question. Does it cover the changes to I will call it the financial structure underlying the export revenue service and the revenue.

Does it capture those?

MR. BLAIR: The proposal is to keep the rate in place for five years, so it would not capture updates to an ETS rate that would be calculated.

DR. HIGGIN: Okay. Thank you. That was helpful. Could we now, please, turn up Exhibit I, tab 2, schedule 8, and page 3 of that? I will just let you, you know, just have a look at it and be familiar with this.

If you want to go back and look at the question, that would be also appropriate.

MR. BLAIR: I am familiar with this response.

DR. HIGGIN: Yes, okay. You prepared it, okay.
MR. BLAIR: Yes.
DR. HIGGIN: There is another question here. That is the difference between the 1 CP and the 12 CP, okay?
MR. BLAIR: Yes.
DR. HIGGIN: This question asked you to produce an estimate using the actual hourly data, correct, '21?
MR. BLAIR: Yes.
DR. HIGGIN: If you look at the results, if you move down a little bit, you see that the result is that there is a significant change for that change. In other words, going to, using actuals rather than the proxy 12 CP. There is a material change. Is that correct?
MR. BLAIR: There is a change. I will clarify the previous figures were the 2020 actuals.
DR. HIGGIN: Yes, okay.
MR. BLAIR: Rather than the forecasts.
DR. HIGGIN: All right. So the question to you is, methodologically, should there be an update to reflect the actuals as we go forward and calculate the ETS rates?
MR. BLAIR: I think for rate stability purposes, it would make sense to keep it fairly consistent for a number of years in a row. I do recognize the figures have changed quite a bit from the 2020-2021 using the same 2023 revenue requirements.
And I think it would be better to have stable rates than to adjust that each year, which may go up or down based on maybe the previous year, whichever forecast at

that time.

DR. HIGGIN: Now the other option to adjusting rates, you are familiar with regulatory, is a deferral account. You are familiar with those?

MR. BLAIR: Yes.

DR. HIGGIN: So do you have an opinion whether a deferral account could be a useful asset to setting the rate and then, as you say, you don't change the rate, but you put the money into the deferral account, like all of that other money that is going into the other deferral accounts.

MR. BLAIR: I wouldn't say necessarily that it should be used, but it can certainly be used for that purpose and it would achieve that goal that you described.

DR. HIGGIN: Right. Okay. Thank you for your response.

I think you will be glad to know those are my only questions. Most of the other ground has been plowed before by others. So thank you for your responses, Mr. Blair. Thank you.

MR. BLAIR: Thank you, Doctor.

MR. SIDLOFSKY: Thanks, Dr. Higgin. That leaves us with Mr. Pattani, followed by OEB Staff.

So let's take our afternoon break now. It is just after -- just after 2:30. Let's come back at 2:50. And we will see you then.

--- Recess taken at 2:31 p.m.

--- On resuming at 2:50 p.m.

MR. SIDLOFSKY: Good afternoon. We are back with panel 3 from Elenchus. Mr. Pattani, you are up next.

EXAMINATION BY MR. PATTANI:

MR. PATTANI: Thank you, thank you. Good afternoon, Mr. Blair.

MR. BLAIR: Hello.

MR. PATTANI: So most of my questions have been answered in your responses during the session before the break. So I only had one two-part question to seek clarification about some numbers about correlation between the network revenue requirement and the ETS rates in your cost-allocation methodology.

So in IR Exhibit I-6-1 -- I should wait for it, I guess. Anyway, let me just go ahead. So it is Exhibit I-6-1. You indicated in part C that about 44.3 percent of the total network pool revenue requirement comprises shared network asset-related costs. I think it is on the next page, item C.

MR. BLAIR: Yes.

MR. PATTANI: Okay. Now, if you don't mind, can we refer to -- I don't know if you want to open it, but we would like to refer to table 15 on page 35 of your cost-allocation report, which was attachment 1 of the joint Hydro One-IESO submission in this proceeding.

You probably don't need it yourself, but I guess if it is already there.

Great. So in this table you've got the several final conclusion of registered ETS rates. And if we refer to this table, can I -- is it -- can I say from this table that for the first option in this table, which is titled allocation on basis of 100 percent of shared network fixed assets, can you confirm that the ETS rate of 6.54 percent -- 6.54 dollars per megawatt-hour is, therefore, reflective of allocation of costs from 44.3 of the percent of the total network revenue requirement? Because --

MR. BLAIR: Yes. I think, to make a clarification or perhaps a correction, that 44.3 percent figure is the shared -- is the shared asset-related costs as a percent of the total revenue requirements. So it is not specific to the network pool.

MR. PATTANI: Okay. So it is 44.3 percent of the shared network pool, and shared network pool, I believe, is 66.3 percent of total?

MR. BLAIR: Shared, it's 60.2 percent.

MR. PATTANI: So this is therefore reflective of allocation of costs from 44.3 percent of 66.3 percent of the total network pool revenue requirement?

MR. BLAIR: Could you repeat those figures?

MR. PATTANI: Sorry?

MR. BLAIR: Could you repeat your question?

MR. PATTANI: So is 6.54 a reflection of 44.3 percent of total network pool -- of shared network pool revenue requirement, which in itself is 66-point-something percent of the total network pool revenue requirement?

MR. BLAIR: The 44.3 percent figure is the percentage of shared network asset-related costs as a percentage of the full revenue requirement.

So the 6.54 figure -- actually, if you could scroll up a bit on the page there, the 6.06 figure reflects the 44.3 percent allocation of shared assets, but it is also a percentage of inter-tie -- of inter-ties. That should be included in addition.

MR. PATTANI: Okay. So inter-tie, I believe, is 6 percent. But let's -- in one of -- one of the Hydro One --

MR. BLAIR: It is 0.6 percent of costs are dedicated interconnects, so it is a small portion. In the table below, table 15 has the same rates, but they're inflated for the -- all the transmitters, so it includes the other transmitters included in the UTR.

MR. PATTANI: So, I mean, you know, let's assume that .6 is here or there. So it is reflective of allocation of about somewhere around 44 to 50 percent of the network on network pool revenue requirement. I just want to get a --

MR. BLAIR: Yes, that's correct.

MR. PATTANI: -- and get a feel for it. Okay.

Now, then the other option that I would like to address here in this same table is the second one, which is allocation on basis of 50 percent of the shared network fixed assets. So because this allocation is using a 50 percent of the shared network fixed asset now, then I am assuming, or can you please confirm then, that the ETS rate of 3.66 dollars per megawatt-hour is, therefore, reflective of allocation of costs from about 22 -- 22 to 25 percent of the total, because it is 50 percent of what we just discussed about option one?

MR. BLAIR: Yes. It is 50 percent of the shared network asset-related costs, but the -- there is also that portion for inter-ties.

MR. PATTANI: Yes.

MR. BLAIR: I also want to clarify that these rates include other revenues that have been added to the bottom to net off some of the costs.

MR. PATTANI: When you say "other revenues", but these are revenues that still belong to total network pool revenue requirement. Like, Hydro One's beginning of the network pool revenue requirement is about 1.8 billion dollars, I believe, somewhere around there.

MR. BLAIR: Yes, 1.823 billion. And then there is other revenues that offset that total amount. So the rates revenue requirement is lower than that amount.

MR. PATTANI: Yes, so it's slightly -- so it is -- it is about 24 or 30 percent of that, whatever you are talking about, just a network pool revenue requirement.

MR. BLAIR: Yes. In general you're correct. Just a small qualification along the way that there is minor differences.

MR. PATTANI: Yeah. So we are looking at -- in short, all I am trying to get at is the option one is about half of what it would have been if you hadn't gone to this number -- motion of doing the shared network asset and removing something and removing half of it allocated and so on.

So option one is that. And option two is about one-fifth of what it would have been otherwise, if you are not bothered with this very nice allocation methodology that you have.

MR. BLAIR: It is approximately one-fifth reduction.

MR. PATTANI: Yes, yes.

MR. BLAIR: Okay.

MR. PATTANI: To one-fifth. It is four/fifth reduction.

MR. BLAIR: No. The last scenario there it removes 20 percent. So 80 percent remains. So that is -- the 80 percent is higher, the rate is higher than the 50 percent scenario, because only 20 percent of the net shared assets to -- allocated to the export class, which leaves by 20 percent. So it is -- that amount is higher. It is reduced by 20 percent, not the 80 percent.

MR. PATTANI: Okay. Thank you very much, Mr. Blair.

I am done, Mr. Sidlofsky.

MR. SIDLOFSKY: Thanks, Mr. Pattani.

Last questioner of the day is Mr. Pietrewicz for OEB staff.

EXAMINATION BY MR. PIETREWICZ:

MR. PIETREWICZ: Good afternoon, Mr. Blair. My name is Andrew Pietrewicz. I will be asking questions on behalf of OEB staff. A lot of the questions I was planning on asking have already been addressed, so I only have a handful or so.

First I would like to invite you to help us understand the difference between the 12CP allocator and the composite allocator, and I will provide context for that.

As I understand it, the approach laid out in the Elenchus 2021 report starts with functionalization, classification, and then allocation.

And I understand that it is in the context of allocation that the concepts of 12 critical peak or 12CP or CP allocator and the composite allocator are raised. Is that basically true, that it is in the context of allocation that those concepts are introduced?

MR. BLAIR: Yes. And as well as 12CP is the 12 coincident peak.

MR. PIETREWICZ: Yes, yes, thank you. And so -- and it is really that, if I could invite you to help us understand in simple terms what the 12CP allocator is and where is it used in the 2021 Elenchus report; likewise, what the composite allocator is and how it is calculated and where it is used in the Elenchus report.

Do they allocate different things, same things? If you can briefly explain for us, in plain terms, what these things are and what they're used for in the 2021 report.

MR. BLAIR: The 12CP looks at the coincident peak on the system each month for the 12 months and the highest peak in each of the 12 months the peak hour is used in.

And then you have the 12 coincident peaks and the export and domestic demand in each of those peaks.

And you sum the totals, the sum of the 12, and that is the 12 CP. One CP would be taking just the highest peak, and then there is also a 4 CP considered in the model that has the four highest.

That is what is used to allocate net fixed assets. And in the 2021 methodology, really the net fixed assets allocator -- it is not really a composite allocator. It is the 12 CP allocator because every asset that is allocated that way is the 12 of CP. So there is no difference between 12 CP and that composite net fixed asset allocator.

MR. PIETREWICZ: Thank you. What is the composite allocator? And what is it used for, for example? Is the composite used only to allocate O&M costs between export and domestic rate classes, whereas capital costs are allocated on the basis of 12 CP? How would you characterize it?

MR. BLAIR: In the 2021 report, OM&A and assets are all allocated by 12 CP.

In the 2014 methodology, OM&A was allocated by a composite allocator. So that is -- the difference is that the allocator was based on the allocation of other assets and then this was calculated based on how all of those other assets were allocated, and that is the basis for calculating OM&A. But in this methodology is the 12 CP for each of these cost categories.

MR. PIETREWICZ: Thank you. That is very helpful.

Turning to OEB Staff 8, OEB Staff asked Elenchus about why the last year 12 CP is used to -- sorry, why the last year's 12 CP is used to allocate assets instead of the three-year historical rolling average 12 CP.

And Elenchus replied -- I am just trying to find it here. Oh yes, in part A of the response on page 2 of 2 of the response, Elenchus responded that:

"the most recent year 12 CP was selected to reflect the most recent relative domestic and export demands and to correspond with the time period of the megawatts volumes used as the billing determinant."

I would really appreciate if you could clarify for us what you mean by correspond with the time period of the megawatt volumes used as the billing determinant. For example, when you say billing determinant, what are you referring to?

MR. BLAIR: By willing determinant, I mean the megawatt-hour volumes that are used to divide the revenue requirement allocated to the export class divided by the export volumes.

MR. PIETREWICZ: Thank you. Moving along to OEB Staff 14 -- actually OEB Staff 13 first, please, by way of prelude.

Here OEB Staff asks Elenchus about allocating a portion of inter-tie costs -- or interconnection costs, as I think we refer to them here -- allocating a portion of interconnection costs to domestic customers.

And in response to OEB Staff 13, part A, Elenchus excerpts a bit of the 2021 Elenchus report.

So if you turn to page 2 of 2 of that response, on lines three to five it says:

"Energy is imported to serve domestic load,
therefore a portion of interconnection assets,
asset related costs, and OM&A should be allocated
to the domestic class."

I just want to make sure that you see that one there.

MR. BLAIR: Yes.

MR. PIETREWICZ: Okay, great. So we will move on to OEB Staff 14 that I think says that "and the percentage of interconnection assets, asset related costs and OM&A that should be allocated to the domestic class is 28.29 percent." Is that a correct understanding?

MR. BLAIR: Yes.

MR. PIETREWICZ: Okay, great. Thanks. I think based on our foregoing discussion, you have already confirmed this, but can you confirm that the ETS results, the Elenchus study results summarized in the table in the executive summary of the Elenchus report, do they include some allocation of interconnection costs to domestic customers?

MR. BLAIR: Yes, they do.

MR. PIETREWICZ: Okay, great. And I think you agree -- or would you agree that is the allocation of this 28.29 percent to domestic customers of interconnection costs, is that based on the inter-tie 12 CP?

MR. BLAIR: Yes.

MR. PIETREWICZ: Okay, thank you for confirming that.

Now, here's the question that I would like you to think about. Would you agree that some of the inter-tie 12

CP released import demand that enters Ontario and is consumed in Ontario, whereas some of it represents import demand that enters Ontario and leaves Ontario as a wheel through export. Would you agree that is the case?

MR. BLAIR: I would agree that is the case, yes.

MR. PIETREWICZ: So not all of it stays in Ontario. Not all of it is consumed by Ontarians, right?

MR. BLAIR: That's right.

MR. PIETREWICZ: Yes. So therefore, I wonder -- I would like to hear your thoughts on recognizing that some of that power, some of the power that is imported to serve domestic loads is imported to serve domestic loads, but that some of that imported power actually flows across as a wheel through. Is there a principled reason, in your view, to say that as a potential future refinement that the share that Ontario domestic loads pay for interconnections ought to be perhaps less than the amount that is included right now in the Elenchus 2021 report, ought to be less than that 28.29 percent based on 12 interconnection CP?

MR. BLAIR: Yes. I would agree that is reasonable. We didn't consider the volumes that are wheeled through in setting this allocator.

MR. PIETREWICZ: Okay, thank you. Moving along to OEB Staff 18, we heard yesterday and perhaps today and on the record that exports are curtailable.

MR. BLAIR: Yes.

MR. PIETREWICZ: And operationally speaking, when push comes to shove, that exports can receive a different priority of service from domestic loads. They're curtailed first.

And here OEB Staff -- on OEB Staff 18, we ask about these three cost-based methodologies that were considered by Elenchus to be appropriate options to allocate shared network asset-related costs to export customers.

And I would like to ask you a little bit about them, in fairness, related to this idea that maybe exports are not, you know, an equivalent cost to domestic folks.

I understand that on line ten of the interrogatory, Staff 18, it identifies option 1. Option one, right, which is the fully allocated shared network asset related assets, on the basis of shared net fixed assets. This is, you know, the full allocation method.

And I understand from previous responses on the record that Elenchus feels this reflects actual export demand and, you know, that demand could have been higher to the extent that some exports were curtailed.

But this 12 CP method, option one, in your view, does it reflect actual export demand on the inter-ties?

MR. BLAIR: This related to net fixed assets is 12 CP for the system as a whole, rather than just on the inter-ties.

MR. PIETREWICZ: Okay, thank you. That is helpful. And it reflects exporters' use of the system as a whole as, you know, as seen in the 12 CP periods.

MR. BLAIR: Yes.

MR. PIETREWICZ: Thank you. Here is the question that

I invite your thoughts on, which is does this option one, although it implicitly captures any curtailments that might have been pinned to exports, does it really reflect, in your view, the fact that exporters receive a different level of service than domestic loads?

And I ask in the context of, does this jive with the concept of fairness and is that what the 80 percent option was meant to try to address? That is where I am going with this.

MR. BLAIR: Right. It is sort of the maximum of the range that would be considered reasonable on a cost basis. We do mention there is -- to a certain extent, export volumes may be curtailed at peak times and there should be -- so that naturally in the data there already is a small degree of recognizing they have lower priority access and if you want to attribute additional level of consideration that they have lower priority access, then you might move to option B or C or option 2 or 3.

MR. PIETREWICZ: Thank you. And just kind of your initial impression or your thoughts, given your work on this.

Would you say that the option 1 in your view appropriately reflects the different class of service that exporters receive, given that it has already implicitly captured curtailments that have occurred?

MR. BLAIR: I wouldn't say it fully captures the extent that they're curtailed.

MR. PIETREWICZ: Okay. Thank you for that. And is it fair, again, that the 80 percent option tries to go a little bit of a ways or all the ways to capturing that idea?

MR. BLAIR: Yes. It was a way to capture that maybe there would be a lower-level priority and to assign some sort of -- the variable of how many hours do (sic) they actually curtailed in. That would be good proxy to moving forward if the same methodology was adopted in the future. If they're curtailed less, then they would be allocated more in the future.

MR. PIETREWICZ: Right. So the 100 percent methodology then captures ones you manage to get in through the door, but it doesn't quite capture the fact that there are others that would have been curtailed first ahead of domestic loads before they even got to the door. That is a very convoluted question. I will just nix that. I was just thinking out loud. Lesson to self. Don't think out loud.

Okay. Moving on. In principle, do you think -- I understand that the 80 percent option relates to -- like, it discounts it by 20 percent, assuming that exports were curtailed in 20 percent of the hours or over the last two years, 20 percent of the hours.

What I want to ask you is, in principle, would the quantity of megawatts curtailed be more or less equally appropriate in [audio dropout] discounting instead of the quantity of hours curtailed? Like, the percent of megawatts be equally as appropriate as percent of hours?

Do you have any initial thoughts on that?

MR. BLAIR: That could be another reasonable way to adjust the export CP, yes.

MR. PIETREWICZ: Right. Okay. Thank you. I will move on to the third option. It is the second one shown in OEB Staff 18. That is this 50 percent -- this 50 percent method.

And in plain language, how does that fit in with the fully allocated, the 80 percent option, and here is the 50 percent. Can you in your own words describe that to us?

MR. BLAIR: It would be described as a hybrid version, and it really is just a compromise, 50 percent, that's not based on any particular figure. It is consistent with the pole attachment decision that was cited by the OEB in the transmission decision when they directed OEB -- directed Hydro One to undertake the study.

So it is a good -- something that the Board would want to see at least is, what would cost be at 50 percent, what would the rates be if this discount [audio dropout] 50 percent.

MR. PIETREWICZ: Okay. Thank you. And is it fair to say that the 50 percent -- whereas the second option, the 80 percent kind of had to do something with curtailments or different priority service, is it fair to say that the 50 percent option doesn't explicitly have anything to do with the curtailments, it is more about -- or maybe analogy to the pole attachments idea?

MR. BLAIR: Yes. It is more of an analogy to the pole attachments, yes.

MR. PIETREWICZ: Okay. Okay. And can you remind us arithmetically, what does the 50 percent refer to? It is 50 percent of what? Can you help us understand or remind us what it is?

MR. BLAIR: Yes. We have the 12 CP volumes and the full volumes for the domestic class and the volumes for the export class. And unadjusted it is about 90 percent domestic and 10 percent export.

The adjusted removes 50 percent of the export quantities, the export demand. So it is not quite 95 percent when you do 50 percent, because you are removing some of the total -- the denominator in that calculation, but it is -- it is assuming they have half the capacity that they actually do. Or they actually use, I should say.

MR. PIETREWICZ: So it is allocating less of the shared assets to exporters in this case, right?

MR. BLAIR: Yes.

MR. PIETREWICZ: It is allocating less of them. Thank you.

I will move just to my final question then. If you wouldn't mind going to OEB Staff 12. And this kind of picks up on some of the discussion you were having earlier with, I believe it was Mr. Harper, about in your scan of external jurisdictions there didn't seem to be a difference between -- there weren't separate domestic and exporter transmission rate classes, right?

My question to you -- by the way, is that a fair characterization? I don't want to put words in your mouth, but is that a fair characterization?

MR. BLAIR: Yes, that's fair.

MR. PIETREWICZ: Okay, thank you. And my question to you is, in the Ontario context, would such a rate be akin to exporters paying the same OEB-approved uniform transmission rates that domestic customers pay?

MR. BLAIR: I'm sorry, could you repeat the question?

MR. PIETREWICZ: Yes. If your finding is that outside of Ontario exporters pay the same rates that domestic customers do?

MR. BLAIR: Yes, that is what we find.

MR. PIETREWICZ: If it was, like, you know, if we kind of assume that model in Ontario, would that effectively mean that export customers would pay -- would that be equivalent to export customers paying the UTR, the uniform transmission rate, in the same way that domestic customers do?

MR. BLAIR: Yes. It would be the same rate.

MR. PIETREWICZ: Okay. And in your view, would an export transmission service rate in Ontario that is equivalent or roughly equivalent to today's UTR rate be appropriate as an ETS, and is that what you are showing in your options?

MR. BLAIR: I think equivalent rate wouldn't necessarily be appropriate, because there is the less access that exports have --

MR. PIETREWICZ: Okay. Thank you.

MR. BLAIR: -- wouldn't make sense to have a lower rate than the UTR. And also, I want to point out that there is line connection and transformation costs that are charged to domestic customers that are not charged to export customers.

MR. PIETREWICZ: Thank you. That's been very helpful. Those are all of my questions, thank you, Mr. Blair.

MR. MYERS: Can I just ask one clarification as a follow-up to that last question?

MR. SIDLOFSKY: Sure.

RE-DIRECT EXAMINATION BY MR. MYERS:

MR. MYERS: Mr. Blair, can you also speak to how that scenario would relate to the consideration of other benefits which you talked about earlier?

MR. BLAIR: If the rates were the same? If the exporters paid the UTR rates?

MR. MYERS: Yes.

MR. BLAIR: Well, that would also not -- probably wouldn't consider the aspects of the APPrO report -- or the Power Advisory report and the IESO, the other considerations for the Board to consider, if I wanted to be consistent with all the principles that are considered here to have the same rate.

MR. MYERS: So using the UTR -- the UTR approach, that is more in the nature of pure cost allocation?

MR. BLAIR: Sorry, could you repeat that?

MR. MYERS: Using a UTR approach for exporters, are you saying that that is more in the nature of pure cost allocation and doesn't take into account the consideration of all of those other benefits and factors that you have talked about earlier?

MR. BLAIR: If it is the same rate, then there would be no cost-allocation aspects to it at all. It would just be pure rate-making based on the revenue requirement divided by the billing determinant, and then what should the rate be based on that. It would kind of bypass the cost-allocation aspect of it if you were to take the UTR rate and move from there to what ETS should be.

MR. MYERS: Okay. Thanks very much.

MR. SIDLOFSKY: Mr. Blair, thanks very much.

Mr. Pietrewicz, you were the last questioner for the day.

Thank you all, those of you who are still on the line, thank you all for keeping to time limits and scoping your questions. I appreciate it.

That is all for today's technical conference. Next key date in this proceeding is August 4th. Two things are happening then. There is the transcribed presentation day before the OEB panel, and any technical-conference undertakings are due also on August 4th, next Thursday.

Thanks very much. Mr. Price, did you have anything to say?

MR. PRICE: No.

MR. SIDLOFSKY: Okay.

MR. PRICE: You said what I was going to say, so thank you, Jamie.

MR. SIDLOFSKY: Okay. And thanks to our reporter. Have a good long weekend, everybody.

MR. MYERS: Thanks, Jamie.

MR. RUBENSTEIN: Thanks, Jamie.

MR. DeVENZ: Thank you.

--- Whereupon the hearing concluded at 3:21 p.m.