ONTARIO ENERGY BOARD

FILE NO.: **EB-2023-0195** **Toronto Hydro-Electric System Limited**

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EB-2023-0195

THE ONTARIO ENERGY BOARD

Toronto Hydro-Electric System Limited

Application for energy distribution rates beginning January 1, 2025

Technical Conference held in person and by videoconference from 2300 Yonge Street, 25th Floor, Toronto, Ontario, on Monday, April 8, 2024, commencing at 9:34 a.m.

TECHNICAL CONFERENCE

A P P E A R A N C E S

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CLEMENT LI	Building Owners and Managers Association (BOMA)
TOM LADANYI	Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC), Energy Probe Research Foundation
JULIE GIRVAN	Consumers Council of Canada (CCC)
NICK DAUBE	Distributed Resource Council (DRC)
KENT ELSON	Environmental Defence (ED)
MICHAEL BROPHY	Pollution Probe
DAN ROSENBLUTH BAYU KIDANE	Power Workers' Union (PWU)
MARK RUBENSTEIN JANE SCOTT	School Energy Coalition (SEC)
MARK GARNER 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

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

Monday, April 8, 2024

--- On commencing at 9:34 a.m.

MR. MURRAY: I think we'll get started now. This is the technical conference for OEB file number EB-2023-0195, which is Toronto Hydro's custom IR application. My name is Lawren Murray, and I am counsel to board staff. Before my interjectory remarks and appearances, I'm going to hand things over to Ms. Sanasie, the hearings advisor, who will begin with the land acknowledgement.

LAND ACKNOWLEDGEMENT:

MS. SANASIE: The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many nations, including the Mississaugas of the Credit, the Anishinaabeg, the Chippewa, the Haudenosaunee, and the Wendat Peoples. This area is now home to many diverse First Nations, Inuit, and Métis Peoples. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit. We are grateful for the opportunity to gather and work on this land, and recognize our shared responsibility to support and be good stewards of it.

MR. MURRAY: Thank you, Ms. Sanasie. A few quick administrative matters before we get started: First, this technical conference being transcribed, and the transcription will form part of the record of this proceeding. For the benefit of the court reporter, we are recording today's session, but that recording will not be posted.

Second, a reminder that the technical conference is being live-streamed on YouTube, se be mindful, including during breaks, that there may be people watching other than those you see appearing on the screen.

And, third, while the chat function is enabled and available on Zoom, nothing said in the chat function will be recorded or appear in the transcript of today's technical conference.

With those preliminary remarks, I wanted to just say something briefly about the next five days. We have a very busy five days ahead of us. As people will know, the time estimates exceeded the available time by a wide margin, so we have provided a revised schedule that will see that the technical conference is completed within the allotted time. I would ask that everyone here, both the witness panel and the questioners, work together to ensure we can stay on schedule.

With me here today from OEB staff are my co-counsel, Charlotte Kanya-Forstner; case manager Thomas Eminowicz; senior advisor Margaret DeFazio; our accountant, Dana Wong; manager of major applications, Donald Lau. There will also be other members of OEB staff who will appear at points during the technical conference to ask questions in their subject matter area.

Let's get started now with appearances and proceed in the order of the schedule. Mr. Garner.

APPEARANCES:

MR. GARNER: My name is Mark Garner, and I'm a

consultant with the Vulnerable Energy Consumers Coalition, and I am here with -- I will let you introduce yourself, Mr. Harper.

MR. HARPER: My name is Bill Harper. I am also a consultant with the Vulnerable Energy Consumers Coalition.

MR. MURRAY: School Energy Coalition.

MR. RUBINSTEIN: Good morning. Mark Rubenstein, counsel for the School Energy Coalition, and, appearing virtually from time to time, set consultant, Jane Scott.

MR. MURRAY: AMPCO.

MS. GRICE: Good morning. Shelly Grice, consultant for the Association of Major Power Consumers in Ontario.

MR. MURRAY: DRC.

MR. DAUBE: Good morning. I am Nick Daube, appearing for DRC.

MR. MURRAY: CCC.

MS. GIRVAN: Good morning. It's Julie Girvan, and I am a consultant to the Consumers Council of Canada, and I will be attending later this afternoon. Thank you.

MR. MURRAY: PWU.

MR. ROSENBLUTH: Good morning. It's Dan Rosenbluth, counsel for the Power Workers' Union, and I am accompanied by Bayu Kidane.

MR. MURRAY: Environmental Defence.

MR. ELSON: Good morning. My name is Kent Elson, and I represent Environmental Defence.

MR. MURRAY: Pollution Probe.

MR. BROPHY: Good morning. My name is Michael Brophy,

and I'm here on behalf of Pollution Probe.

MR. MURRAY: CCMBC.

MR. LADANYI: Good morning. My name is Tom Ladanyi. I am consultant for the Coalition of Concerned Manufacturers and Businesses of Canada.

MR. MURRAY: Energy Probe.

MR. LADANYI: And also my name is also Tom Ladanyi. There are not two of me. I'm a consultant representing Energy Probe.

MR. MURRAY: Just looking, did I miss anyone in terms of the -- oh, BOMA.

MR. LI: Good morning, Clement Li, representing BOMA. I'm attending virtually today.

MR. MURRAY: Did I miss anyone's name in terms of the questioners? No. Before I hand things over to Mr. Keizer to introduce his first witness panel, I just want to canvass the room to see if there are any preliminary issues. Hearing none, I will hand things over to Mr. Keizer to introduce Hydro One's first panel.

MR. KEIZER: Well, so it's actually Toronto Hydro.

MR. MURRAY: Toronto Hydro.

MR. KEIZER: But, also, I should put in an appearance. My name is Charles Keizer, external legal counsel for Toronto Hydro. With me today is Daliana Coban, director of regulatory affairs, Toronto Hydro; and also appearing will be Mr. Arlen Sternberg. I will put in appearance for him, as well, as external legal counsel for Toronto Hydro.

The first panel is ready to go. Maybe what I will ask

is that, if each panelist can in their -- starting here, at the left, if you could introduce both your name and your title, and then proceed along through the panel, that would be appreciated.

MS. MARZOUGHI: Good morning. My name is Rei Marzoughi. I'm the manager of the non-wire solutions team at Toronto Hydro, in the engineering division.

MR. HUNTLEY: Good morning, everyone. My name is Kirk Huntley. I'm the director of stations and capacity planning and grid innovation of Toronto Hydro.

MR. HIGGINS: Good morning. My name is Matthew Higgins. I am the director of integrated planning and modernization at Toronto Hydro.

MS. NARISETTY: Good morning. Sushma Narisetty, I'm the director of the standards team at Toronto Hydro.

MR. MUNDENCHIRA: Good morning. My name is Githu Mundenchira. I'm the senior manager of finance capital planning at Toronto Hydro.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED - PANEL 1

Rei Marzoughi

Kirk Huntley

Matthew Higgins

Githu Mundenchira

Sushma Narisetty

MR. KEIZER: Thank you, panel. I think, just so you're aware, that you do share mics, so just so you are aware as you are turning on and off. We don't have any preliminary matters. I spoke with [audio dropout] and Mr.

Harper about some questions that they had filed earlier in the week, and Toronto Hydro is prepared to deal with those questions that were filed as written questions, so I leave it to Mr. Harper to bring that up, and maybe we will mark it as [audio dropout].

MR. MURRAY: Would you like to do that now, Mr. Harper, or is there somewhere in your --

MR. HARPER: No. My first item on my agenda after making sure everybody knew my name was to note that we had filed a letter on April 2nd, giving our time estimates and some of the questions we planned on asking, and asking if we can make that an exhibit number since I had planned on referring to it during the course of the week.

MR. MURRAY: That will be Exhibit KT1.1.

EXHIBIT NO. KT1.1: VECC LETTER FILED APRIL 2, 2024.

MR. MURRAY: And, Mr. Keizer, do I have it correct that Toronto Hydro is prepared to answer those questions?

MR. KEIZER: Well, actually, Toronto Hydro is prepared to answer them in writing, so it may be best if we mark them as an undertaking, actually.

MR. MURRAY: That is what I was going to think. That will be undertaking JT1.1.

UNDERTAKING JT1.1: TO RESPOND TO VECC TECHNICAL CONFERENCE QUESTIONS IN EXHIBIT KT1.1.

MR. HARPER: And I guess the only thing I wanted to clarify was that JT1.1, did it have four questions identified for this panel? I think in my review of the panel assignments I noted at least one -- it was the second

question -- that probably should go to panel 4, and I was wondering if there were any other questions, just so I know which questions are being answered under which panel, if there are any other questions other than the second one out of the four that you feel will be best addressed by a different panel.

MR. KEIZER: Yes, Mr. Harper. So the question identified as TCQ 2 is going to panel 4; TCQ 3A and B will go to panel 4; TCQ 4B will go to panel 4; And TCQ 4C will go to panel 4.

MR. HARPER: Thank you very much.

MR. MURRAY: Thank you.

MR. HARPER: And I guess, with that, actually the questions filed were the only ones that I had for this panel, so I can turn it over to Mr. Garner, who I believe also has some questions for this panel. Thank you very much.

MR. GARNER: I do have a slight preliminary matter, just as introducing the panel. It may be me, Mr. Keizer, but were CVs and names handed out for the panels? It's just that I'm a very slow note-taker on everybody's name. Was that circulated somewhere electronically?

MR. KEIZER: The names were circulated, but I don't believe the Toronto Hydro filed CVs.

MR. GARNER: Okay. Well, maybe look into whether you wish to do so at the break, I'll find the names, though, thank you.

MR. KEIZER: We'll try to make it available to you,

Mr. Garner.

EXAMINATION BY MR. GARNER:

MR. GARNER: Good morning, panel. I'm going to be very brief; I don't have a lot of areas I want to focus on, but I do have a couple. And the first one is I don't know if someone can bring these up. It's 1B-CCC-10, and I just want to talk a little bit about this interrogatory, but also other interrogatories related to it. And what I would like your help with, if you could, is in this interrogatory there's, basically, a discussion about assets past their useful life, and you will see in a figure that's used of 24 percent in 2018 and 23 percent in 2023, so when I read this, I was curious as to how those numbers, first of all, had been calculated.

And then you gave a reference to 2-SEC-44, but I didn't find that actually responded to how that was calculated, but I did find an interrogatory that I did think showed how they were calculated and I'm wondering if you could just tell me if I have this right. So, if I go to 2B-SEC-31, and there's a table in that interrogatory. You're there. Is how the 24 and 23 percent the math behind it calculated by the simple addition of those columns, is that how it's done?

MR. HIGGINS: That's -- well, that's partially correct, Mr. Garner, so what this shows is the breakdown by asset class, and so, yes, if you sum up those individual percentages, you'll get the total of 24 percent and 25 percent, et cetera.

But, actually, if you're looking for more of a description of the calculation, I would actually direct you to 2B-AMPCO-16. We may have gotten the reference wrong to that VECC IR wrong in the drafting, but 2B-AMPCO-16 actually has a plain language description of how we calculate the assets past useful life.

MR. GARNER: Right. And I think I recall that. One of the things I was also curious about is: If I were to ask you to provide me with the past useful life by that calculation for every year from, let's say, 2017 through to 2023, are you able to do that? Or maybe that's already in there, because my first -- where I'm going with all that, is my first, kind of, question when I read that interrogatory was: Is it basically history that it's always around 24, 23 percent? Is it historically that is basically where the company sits on past useful life assets. That it hasn't changed a lot, is there pattern to it or is it going in a certain direction? So, that's what I was trying to explore.

MR. HIGGINS: I'm just thinking about whether or not we might have some of those data points handy already. Some of them will probably need to be calculated fresh. I would have to check.

MR. GARNER: Well, you did it for 2018, right? That's what I was sort of curious about, so I thought you must have gone through a process to do that. I think I see the 2023 by simply taking that interrogatory we talked about and then I asked myself, could I create, then, all the

years in between or are they already there somewhere in all that pile of evidence that, you know, I've missed.

MR. HIGGINS: There's probably references to a few of those years throughout the records, but I don't think it would be unreasonable within the undertaking period to produce those. So we can, we can take that away and see if that's feasible.

MR. GARNER: If you could take an undertaking to do that, that would be helpful to me. And before we give it a number, if it's acceptable to Mr. Keizer, where I was also going with this is. I was trying to understand, and I believe there is somewhere that's spoken about in the interrogatories, I was trying to understand, over the rate plan, if you actually did precisely what you're proposing, you know, in your plan, is the 23 staying 23 or is it directionally forecast to move in a different pattern?

MR. HIGGINS: Yes, and we did receive questions like that sort of asset class by asset class in the interrogatories, and I think we don't have to go to the IR, but in 2B-SEC-44 we laid out some of the issues around sort of developing those kinds of forecasts for assets past useful life. And so, we don't, we don't have a specific forecast because in a large number of our programs the more volumetric programs like the Horseshoe programs, we don't know which assets we're going to replace, and ultimately there's a number of different things that go into deciding which assets we're going to replace. Besides, you know, is it the oldest asset on the system, so it would be difficult

to forecast that in any meaningful way.

MR. GARNER: Yes, I do recall the interrogatory, and before go further, maybe, Mr. Keizer, I will stop there and just ask if you would take that undertaking to produce the table we spoke of for the 2018 to 2023 period, giving those.

MR. KEIZER: Yes, I think that would be fine, I just wanted to clarify with Mr. Higgins that you said you were able to do that during the undertaking period, is that correct? Is it a lot of work to do or is it something that's...

MR. HIGGINS: It's probably a bit of work to go back and just ensure that, you know, everything is clean and to the same standard of what we have currently filed for assets past useful life, so it will be a bit of an undertaking, if I can use that term, but it should be doable.

MR. GARNER: And just to be clear, to help Mr. Keizer, I think what would be most useful to me, and about the work to be done, the way I would see it if you took 2B-SEC-31 and you basically, it has 2023, and you work that backwards to 2018, so you use that table as your format. Do you know what I mean?

MR. KEIZER: That's fine, sure.

MR. MURRAY: That will be undertaking JT1.2.

UNDERTAKING JT1.2: TO REPRODUCE THE TABLE IN 2B-SEC-31 FOR THE 2018 TO 2023 PERIOD

MR. HIGGINS: Sorry, can I just clarify, Mr. Garner,

it's the table in SEC-31 that you're looking for?

MR. GARNER: Yes, I'm coming to this conclusion, you can correct me, is that when I looked at the CCC interrogatory, the derivation of 25 percent is found by adding up all the columns that are found in the first column of 2B-SEC 31. I will find that same figure of 25 percent?

MR. HIGGINS: Yes, so, I mean, we provided this breakdown to provide an additional level of detail. If that's what you're looking for, we can provide it, I would say the more meaningful number at the end of the day, given the high level nature of this metric is just the overall assets past useful life, so it just sort of depends what you're looking for.

MR. GARNER: I guess the thing -- and I don't want to debate with you really -- I guess the thing is, because I'm going to come to this in the next part of my question. I guess the thing that I'm trying to understand eventually is about how in the future one would make this assessment.

So, my first premise is one had to come up with a math formula to get 24 and 25 percent. I assume this is that formula sitting in that table? And if it isn't, you can --

MR. HIGGINS: No, maybe I can help clarify. Sorry to interrupt. To clarify, so this is not so much the formula, This is just a disaggregation of the statistics by asset class. The formula is more, maybe going to 2B-AMPCO-16 for a moment. So, we describe it qualitatively here. But,

essentially what we're doing for each asset class, we are tallying up the number of assets that are before their mean service life, and the number of assets that are after, dividing each of those numbers for each asset class by the total population for that asset class, and that gives us the percentage of assets before and after useful life for that asset class, and then we are waiting --

MR. GARNER: Sorry, can I just stop you? That gives you the numbers that I'm looking at in table 1, then? Is that how those numbers of percentages for conductors and all that, is that how that number gets derived? So, .5 percent for OH conductor in the first row, do you know what I mean? Like, I'm listening to what you're saying. I'm wondering, so is that how I got to that .5 percent, by taking the aggregate, and then using a proration based on the overall asset in the class?

MR. HIGGINS: So, no, and that is where I think the last point, just to sort of finish the description, the last point, so just we have sort of a hundred thousand poles, right, or more or less. And then we've got a smaller population of large transformers in stations, just to use two examples. If we were to not do any weighting to those asset classes, then the poles would overwhelm the stations assets in the formula. What we end up doing is applying a representative unit cost to scale the different asset classes, so that they're, you know, more so on even footing.

So, those percentages that you're seeing, if you just

take the 2023 column, that would add up to the, I believe, it's 25 percent in the current rate application assets past useful life. But for those individual categories, there's a dollar weighting that's been applied. So that 0.57 percent for overhead conductors, for example, is not kind of the -- if you were to just look at that asset class and the percentage of assets past useful life for that asset class, I believe, subject to check, it would be a different number than the 0.57 percent. So I just...

MR. GARNER: While I digest that, let's go back to the undertaking that you have agreed to do. And I guess what I would say back to you is this table either does or does not, and I heard you say it does, represent the approximation of the 24 and 25 percent in the CCC interrogatory. Correct?

And so it is either in your mind a valid technique to find those numbers, or an invalid technique to find those numbers because you then again use it for 2030, right? And you are demonstrating something in 2030. So it seems to me as, if you are, you are then demonstrating, however this is derived, it has validity to show you something in 2030 because that's what you are showing me in that interrogatory. So I think if I just I have that table that we have discussed, I would see that.

And then what I guess where I was going with the next question of this is what then confused me or I was perplexed by a bit was that your next response that you have given those other Interrogatories that I also recall

which I that, if you can do it in this form, I don't really understand why you cannot replicate it based on your plan that you have proposed to the Board.

So you have a plan, and you are actually showing it for 2030 already, right? So you are showing it at the end of the plan. So I am perplexed why you can't show me the forecast for the periods/years during the plan. You are showing me the end and the start, and then you are saying to me, "But I can't show you what would happen in between."

Sorry, I just don't follow that.

MR. HIGGINS: And so maybe just a clarification, Mr. Garner. The assets [audio dropout] at the end of useful life by 2030, that is we usually describe it using a bit more language in other IRs. That's without any investment. So it's sort of a hypothetical. If we just age the model out with the current asset base, without any intervention, without accounting for failures or anything like that, this is what the --

MR. GARNER: So this is without the investment?

MR. HIGGINS: It is without the investment. Yes.

MR. GARNER: So you haven't done something that shows me, shows anybody, with the investment?

MR. HIGGINS: No.

MR. GARNER: But if can you show me without, then clearly you could show me with, right? -- because you can do it without. And then you are going to invest in the assets. So if your plan says I am going to replace 400 poles, then doesn't it follow you can show me that?

MR. HIGGINS: So again, just going back to my earlier response, Mr. Garner, we tried to unpack this in detail in 2B-SEC-44. The issue in particular with sort of large programs like the Horseshoe program, is we don't know specifically which projects we are going to do, other than sort of 18 months in advance.

MR. GARNER: Right.

MR. HIGGINS: So, for the full five-year period, you know, it's -- we would have to make very broad assumptions about particular assets that we were going to replace, which we are not comfortable doing. So that is the limitation.

MR. GARNER: Okay. I will leave it at that. I don't want to belabour this. But what you are also saying to me, though, is you can tell me what will happen if you don't do it, if that's what that table says. Right, you are saying?

MR. HIGGINS: Correct.

MR. GARNER: We will leave it at that, and with the undertaking. Thank you. It took a lot longer than I was thinking it would.

The second area I would like to explore, and you can go to 1-VECC-5 for this. This is about -- generally, it is about the PIM scorecard. And, forgive me, but I have forgotten what the acronym is now, the performance-something or other, I am sure, scorecard.

And really, what I wanted to focus on with the panel was the issue about scheduled outages, which -- let me start this way: Am I correct to say there are two

scorecards that are talked about in this application? One is the PIM scorecard and one is -- I can't remember what it's called. There is another name for it. Maybe the one, the Board's default scorecard. Is that correct?

They call it -- there's a custom scorecard measures, and then there is a PIM score card measures?

MR. KEIZER: That's right.

MR. GARNER: Right, sorry. That's --

MR. KEIZER: No, I am not right.

MS. COBAN: If I can help you out, Mr. Garner?

MR. GARNER: Sure.

MS. COBAN: There's the 25 to 29 custom scorecard, which is attached to the performance inventive mechanism. And then there is the regular electricity distributor scorecard that --

MR. GARNER: The Board's kind of scores -- scorecard.

MS. COBAN: The Board's standard scorecard. Yes.

MR. GARNER: Okay. Sorry, thank you. That does help me, because I was a little bit confused about how many scorecards I am actually looking at in this thing.

So, as I understand it, on the PIM scorecard, you have removed the idea of tracking scheduled outages. Correct?

MR. HIGGINS: For that particular measure, yes.

MR. GARNER: And now just remind me, is it on the -- but does that measure remain in the Board's scorecard.

MR. HIGGINS: I believe so. Yes, the Board's scorecard only excludes major event days and loss of supply, I believe. Yes.

MR. GARNER: So just so I've got it right, so for the purpose of the Board's default, let's call it the Board's default scorecard, you will be producing a number for scheduled outages, but for the purpose of the incentive mechanism scorecard, you will not be doing that?

MR. HIGGINS: Yes, and if I can just maybe rephrase a little bit: For the electricity distributor scorecard, the Board scorecard, we would be reporting all of the cost codes within SAIDI/SAIFI, according to their definition of the measure. So no proposals to deviate there.

For the purpose of the performance target we are setting, yes, we are proposing to exclude scheduled outages.

MR. GARNER: Now as I recall in the evidence, there is evidence that says that the capital plan that you put forward is going to increase both the number and the duration of scheduled outages. That is correct, as compared to the past averages?

MR. HIGGINS: Yeah. We would expect more scheduled outages. Scheduled outages follow the amount of planned work that we have, so yeah.

MR. GARNER: Right. And the reason, as I understand it, just to -- so I have my understanding correctly, the reason that you say you can't do the scheduled outages has to do with something to do with the tracking mechanism, the OUA, the Oracle database system you are using that is in some way being refined, replaced or in some way done like that. Is that right?

MR. HIGGINS: That's right, Mr. Garner. And I believe it is in Exhibit 1B, tab 3, schedule 1, pages 8 to 9, where we discuss the design of the performance incentive measure, where we do discuss the impacts of upgrades we have made to both our network management system and the introduction of OUA for tracking outages.

MR. GARNER: So is the logical conclusion of that is that the outages, scheduled outages you are reporting to the Board, to the Board's scorecard are defective, will be defective? Is that what you are saying? Because they can't be used for the PIM, they are defective for the Board's purposes?

MR. HIGGINS: No, the issue actually is more with respect to setting a target. We -- in effect, what's happening as a result of the upgrades to NMS and OUA is we are now getting more accurate tracking of scheduled outages, and we do expect that means that we are going to be more inclusive of smaller outages in our tracking. And that is going to drive up the number of outages and, to some extent, the impact on safety and SAIDI.

The issue is forecasting what that impact is going to be because unfortunately, because of the timing, we switched over to the new analytic system in 2022. And so we really only had and still really only have one-and-a-bit years worth of historical data under the new system, which is just not enough to forecast on.

So that was the main reason why we felt we had to exclude scheduled outages from the PIM.

MR. GARNER: And how is it that you know or can say You are going to have more scheduled outages and longer scheduled outages? How do you know that?

MR. HIGGINS: So there's sort of two sides to that. There is the fact that we would expect more --

MR. GARNER: Is it more because the capital program is bigger? Is that the -- okay. It is all it is --

MR. HIGGINS: Yes. That's the main reason.

MR. GARNER: It does bigger things, so it is going to have more scheduled outages. Right? Is that --

MR. HIGGINS: Yes. So, for example, like, there's a number of different kinds of work where we can avoid or minimize a scheduled outage. But when it comes down to ultimately, say, switching out a pole-top transformer or something, there is no way to avoid putting a small handful of customers on a two-, three-hour outage. Our experts on panel 2 can speak a little bit more to more the operational realities there.

MR. GARNER: Right. Okay. So one thing, while we are on that, in 1-VECC-5, you will see there's a response in there about kind of what you are talking about now, which is this communication office will contact people for scheduled outages, et cetera.

Can I just, first of all, before I go too far, can I just ask that somebody on your team just check the reference that you put in the brackets, "Please see Exhibit 1B, tab 3, schedule 3, page 27"? You don't have to do it right now, but I can't find anything at that reference that

actually has to do with this interrogatory. And maybe if it is just the wrong reference -- I kept looking in different places. I couldn't really see what was supposed to be there, but maybe I am wrong. I just put that --

MR. KEIZER: Sorry, can we just -- I don't know if it matches, what you're looking at with what's on the screen. So is it -- sorry, I'm not picking up the reference where you --

MR. GARNER: Okay. So I'm at 1-VECC-5, and I'm at the second page, page 2 of 2, and the first paragraph. Yes, maybe question C. So if you -- Mr. Keizer, if you look at the last line above question, where it says "Question C" in bold, that reference there, it could be maybe there was an update to the evidence or something. I just couldn't find anything.

MS. COBAN: If I can clarify, Mr. Garner, it should be schedule 1 that we are pointing to within that Exhibit 1B, Tab 3, which is --

MR. GARNER: Okay. Well, I will look there again, but I just you to look there again, too, because I thought that, too. I went through all three schedules, but I will take that under advisement and take a look.

Now, having talked about that just clarification, why -- as I understand this, this response, what it also says and I think rightfully, that, you know, there's a discussion about scheduled and unscheduled outages, and Toronto Hydro makes the point they're not equivalents because, scheduled outages, we can deal with the customer,

right, and that's a good point.

But what I was wondering, then, about that is, on scheduled outages, are customers always notified for a scheduled outage or will they be under this plan, or is it just outages of a certain duration? Like how does that work?

MR. HIGGINS: I might ask: Maybe we can punt that question to the second panel. We do have some control-room operational witnesses who would be more versed in the details on that.

MR. GARNER: Okay, fair enough. But, while you're here, let me just pursue that a little bit, maybe on the area that might be more in line with what you're expertise is. When a job is set out for a scheduled outage, is the job assigned a period for the outage, the expected period for the outage, let's say one hour, whatever it is? Is the crew basically given a metric, themselves, to say this is about a one-hour outage, and that's what we're expecting?

MR. HIGGINS: I might again also suggest that we punt that to panel 2.

MR. GARNER: Sure. Well, let me just see if there's anything that I can ask you that's left in this one. Just one moment, please. No. I think in this panel was the issue about the customer surveys you did. And I'm right that the evidence is that, with respect to scheduled outages, there was no surveying of the customers with regards to -- what you said is: It's a bigger plan; there are going to be more scheduled outages.

There was no discussion at all with the customers about that?

MR. HIGGINS: That's correct. I believe we've noted that in the response.

MR. GARNER: Okay. Well, thank you, panel. I think, given what you've helped me with, Mr. Higgins, I think that's where I'll leave this. And thank you, panel, for your help.

MR. MURRAY: Mr. Rubenstein, over to you.

EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Good morning, panel. I have many questions, so let's try, all of us, to get through this. Can we start in 2B-SEC-33? And this interrogatory was noted for both panel 1 and panel 3, so I will try with you guys first. And my question is really with respect to the 7 percent price limit. As I understand, that's for residential customers. I just want to tell you what I think, how I read this interrogatory and some others, and you can correct me if I'm incorrect about it.

As I understand, the 7 percent is an output of the overall budget limit of $4 billion for capital, and $1.9 billion for OM&A. That was a draft budget, and that's where -- and the -- when allocated to residential customers, that's an average [audio dropout] That's my understanding of the 7 percent price. Am I generally correct?

MR. HIGGINS: Just, if you can say that again, you said the draft plan?

MR. RUBENSTEIN: I believe it's the draft plan at the time.

MR. HIGGINS: Yes, that's correct.

MR. RUBENSTEIN: So, then, is it really, was there really a budget limit, or is it really the underlying dollars, the $4 billion and the $1.9 billion for OM&A, that was in essence the limit?

MR. HIGGINS: The three figures go hand in hand, I would say. The three of them are essentially limits for each of those, for each of those areas that we set. You're talking about the price limit and the capex limit and the OM&A limit. Correct?

MR. RUBENSTEIN: Well, I understand that the price limit for residential customers is an output of the budget numbers that I just told, that just we agreed about, the, $4 billion for capital and $1.9 billion for OM&A. So I'm just trying to understand what internally Toronto Hydro actually considered the limit. Is it the dollars or the residential impact?

So, for example, I'll just give you a hypothetical. You know, you can change the load forecast; it may not have an impact necessarily on the dollars, but it may have an impact on the residential, great impact. I am just trying to understand: How, internally, did you look at those two things?

MR. KEIZER: I think that this may be best with panel 3, Mr. Rubenstein.

MR. RUBENSTEIN: All right. Can we move now to 2B-

SEC-54. So, in this interrogatory, we asked you -- we reference some of the evidence that's stated, that the starting point was an iterative process that led to the draft plan. Do you see that? And then we asked you to provide each expenditure plan that was generated during the iterative process, and you provided what you call an initial plan compared to the draft plan. Do you see that?

MR. HIGGINS: Yes.

MR. RUBENSTEIN: I just want to understand. Is that what you mean by the iterative process: There was an initial plan, and then get to the draft plan; obviously there is a final plan after this, but, between the initial and the draft, it's really these two; there was really only those two initial, straight to the draft; there's no other budgets in between?

MR. HIGGINS: That's correct.

MR. RUBENSTEIN: Okay. Thank you very much. Can we now go to 2B-SEC-34. And so, in this part A, we asked you to provide the 2020 gap analysis. This is with respect to ISO 55001. You provide the most recent version, which is dated January 2024, in Appendix A. And, at least as how I read that document, there's really only a 2020 and a 2024 gap analysis that has been undertaken. Am I correct?

MR. HIGGINS: That's correct, yes.

MR. RUBENSTEIN: All right. Now, in part B, you reference something called a "strategic asset management plan."

MR. HIGGINS: Yes.

MR. RUBENSTEIN: What is that?

MR. HIGGINS: Sorry?

MR. RUBENSTEIN: What is that?

MR. HIGGINS: So a strategic asset management plan is part of the standard ISO 55001 guidelines. Essentially, it's the overall master document that sets out your asset management objectives, you know, your overall plan to achieve those objectives, the context for your organization, et cetera.

MR. RUBENSTEIN: And Is it based on when you -- and it talks about you developed a draft plan. Is it based on what you hope processes will look like in the future if you're certified as ISO 55001, or does it represent what you're actually trying to do right now?

MR. HIGGINS: I would say the strategic asset management plan is -- it's not independent of processes, but it's sort of independent of the ISO 55001 journey that we're on. Ultimately, it's a planning document that is considered to be standard, "You shall have one," essentially, if you're going to be certified against the standard.

MR. RUBENSTEIN: Can you provide it?

MR. HIGGINS: The strategic asset management plan?

MR. RUBENSTEIN: Yes.

MR. HIGGINS: So, ultimately, the strategic asset management plan at this time is our distribution system plan that is in front of the board, so the two are one in the same, and that ultimately comes down to, you know, a

matter of timing, our resources were focused on producing the distribution system plan, which captures all the elements of a strategic asset management plan.

MR. RUBENSTEIN: And just to clarify, when you say it's the DSP, is it literally the DSP or, well, we have another document and we've essentially just translated it -- we have a strategic asset management plan, and we're copying and pasting it into what the is DSP?

MR. HIGGINS: For now it is literally the DSP, in the future there may be separate documentation, we're still sort of determining whether or not that will be the case, or if it's more efficient just to produce one document, but, yes, for now it's one in the same.

MR. RUBENSTEIN: Okay. Can I ask you to turn to Appendix A, this is that 2024 gap analysis. And can we first go to page 9 under clause 6.1, I'm just going to ask you about -- it references a number of things and I just want to ask about them. So, the first thing on the second line it talks about the enterprise risk management framework what is that?

MR. HIGGINS: That is the Toronto Hydro's corporate risk management framework.

MR. RUBENSTEIN: Provide a little bit more colour of what that is, what's contained in that.

MR. HIGGINS: So, it is a corporate function. I'm just considering here. Just give me a moment.

MR. RUBENSTEIN: Is it the document you filed in attachment -- in Appendix A to 2B-SEC-43?

MR. HIGGINS: That's helpful, Mr. Rubenstein. Thank you. Yes, that's the interrogatory response I was going to be looking for. So, yes, that is a document that was filed by our ERM team, yes.

MR. RUBENSTEIN: Okay. Well, so let me just -- we'll come back to that, but that's the enterprise risk management framework. There's a lot of similar language, I just want to make sure we're all taking about the same thing. Is it the document or is that just something else that involves risk?

MR. HIGGINS: I just wanted to clarify, so that question was asking for the risk register? And so, that --

MR. RUBENSTEIN: Yes.

MR. HIGGINS: Yes, that covers the universe of risks that we track within the ERM.

MR. RUBENSTEIN: Okay. So, let me, while we have this up, let me ask you about 2B-SEC-43. And so, when you provided this document, it talks about the various, at least how I read it, there's a few slides, it looks like a presentation of some sort, and it provides various risks that the company faces categorized. But what I don't see there is how you plan to mitigate them, mitigation, what are the things that the company is doing to mitigate all the various risks, it just sort of references all the risks. Is your risk management framework, your risk register, whatever language you want to use, contain plans to mitigate the risks?

MR. HIGGINS: So, it is a risk management system, so,

yes, it involves analyzing, quantifying, mitigating risks, yes.

MR. RUBENSTEIN: Well, so is there -- what you provided in appendix -- or attachment A or Appendix A to 2B-SEC-43, just identifies the risks? It doesn't show anywhere about how you're mitigating or how you quantified each of the risks, how you're mitigating the risks. Does that exist somewhere?

And let me clarify, I don't mean that you don't have a plan to mitigate the risk. Is it put in a document, is there something that one can look at that shows here and how we're going to quantify each of the risks that you've presented and how you plan to mitigate them?

MR. HIGGINS: I would have to go back and see if there's a single document or series of documents. Again, we take part in this ERM process on the asset management side partially through a number of risk drivers, but not all of them. So, we would have -- I would have to go back and look at that.

MR. RUBENSTEIN: Well, okay, I will ask you to undertake to do that and then provide it, if it exists.

MR. HIGGINS: That's fine, we'll look to see if there's a document. To the extent that it's provided, we will, if we can't, we'll advise why.

MR MURRAY: That will be undertaking JT1.3.

UNDERTAKING JT1.3: TO PROVIDE FURTHER RISK MANAGEMENT INFORMATION ABOUT APPENDIX A OF 2B-SEC-43.

MR. RUBENSTEIN: All right. Can we go back to 2B-SEC-

34 in the Appendix A, still on page 9, and two thirds down, the answer 6.1, it references a project status report. What is that?

MR. HIGGINS: So, I believe, Mr. Rubenstein, this would be referring to sort of a generic work product that we have at Toronto Hydro called a project status report, which is essentially a way of tracking reporting on any given project, including its risks, et cetera.

MR. RUBENSTEIN: And have you filed any of those on the record? I didn't see a reference to project status report, it's the first time I saw it in this document, so...

MR. KEIZER: I think this may be a question for panel 2, Mr. Rubenstein.

MR. RUBENSTEIN: Panel 2. All right. We'll ask about it then.

Can we go to page 11. And page 11, in clause 7.5, it talks about an asset information strategy draft. What is that?

MR. HIGGINS: Did you say asset information strategy?

MR. RUBENSTEIN: Yes, the first sentence under clause 7.5, you'll see a reference.

MR. HIGGINS: Yes. So, an asset information strategy is another, kind of, core document as part of the ISO 55001 framework. And, essentially, at a high level it defines which information is most critical to the organization, what it's used for, what are the data quality standards, how is it governed, what systems does it live in, et

cetera.

MR. RUBENSTEIN: And is that in the DSP? Like the other --

MR. HIGGINS: No, that document is currently under development.

MR. RUBENSTEIN: And you're not using it, as I understand; is that still the case?

MR. HIGGINS: No, the document is currently under development.

MR. RUBENSTEIN: So, it's not being used?

MR. HIGGINS: No.

MR. RUBENSTEIN: The sentence says the asset information strategy is currently being developed but has not been finalized nor is it being reviewed or approved. So, I take it as it's not being used or is it being used?

MR. HIGGINS: No, it's not being used.

MR. RUBENSTEIN: Okay, thank you very much. Can we go to page 13. If we can go down to internal audit.

And so, about four lines from the bottom in clause 9.2, internal audit it says:

> "An external audit was performed for AMS processes in 2022. An internal audit was not completed to avoid duplication."

Do you see that?

MR. HIGGINS: Yes.

MR. RUBENSTEIN: And I understand AMS means "asset management system"?

MR. HIGGINS: That's right.

MR. RUBENSTEIN: Can you provide that audit?

MR. KEIZER: Can we just be clear what the relevance of it is first? I think the question as to -- I think it may be intriguing for you but I don't know what's --

MR. RUBENSTEIN: I think it's self-explanatory that an external audit of your asset management system is relevant to this proceeding.

MR. KEIZER: I think the question, I guess, is whether or not it's got information that's actually helpful. I mean, in terms of is it highly technical information or is it...

MR. HIGGINS: We were just conferring, I'm actually not a hundred percent sure what the reference is here. We would have to take that back and just look at the consultant's notes again to see what they're referencing. They interview a large number of people in doing these audits, so it would have come out of one of those discussions with internal audit most likely.

MR. RUBENSTEIN: Okay. Well, I would ask you to do that and produce the document that it's referencing -- it's referring to.

MR. KEIZER: Fine, we'll take it away, look at it and see if we can clarify, and if we can produce it, we will. If we can -- if there's a reason why we can't, we will advise.

MR. MURRAY: That will be undertaking JT1.4.

UNDERTAKING JT1.4: TO FILE THE AUDIT DOCUMENT REFERRED TO AT CLAUSE 9.2 AND THE DOCUMENT IT

REFERENCES.

MR. RUBENSTEIN: So the question relating to an external audit or external review but -- that wouldn't fall into some of the other questions arose in my head when I saw that.

And I would ask you to also undertake to provide a copy of any other external audits or reviews that were undertaken with respect to any material aspects of the business since 2012, that have been obviously not already been provided that are not your financial audit, financial statements, or anything that is referenced in 2B-AMPCO-33 or 4-AMPCO-80B.

MR. KEIZER: Sorry, since when?

MR. RUBENSTEIN: Since 2020.

MR. KEIZER: Can I have a moment? Can you just clarify the two IRs? Sorry, Mr. Rubenstein.

MR. RUBENSTEIN: 2B-AMPCO-33 provides us -- and 4-AMPCO-80B. And just to give you some information, 2B-AMPCO-33 asked you about -- I think it was reviews of specific assets. And there's a list there. And then, in 4-AMPCO-80B, you were asked about external audits. And there's a list there. Obviously, it's an addition to those. Are there any other external audits or reviews?

MR. KEIZER: And, sorry, your question was very broad in terms of relating to everything and anything, and so I guess I am just -- are there particular areas that you want to focus on? Or is there...

MR. RUBENSTEIN: Well, it is related to material

aspects of the business, so if there's an audit of -- I mean, immaterial, that wouldn't count. But, I mean, as you can imagine, I don't know what exists. Right? And this one -- the reason this question sparked is because there's no reference to this audit in any of the other interrogatories.

MR. KEIZER: Fine. And we are going to undertake to look for this audit. I mean, I am just troubled by your "material aspect of the business." I am not sure what that means. You know, in terms of materiality or the -- are you talking -- I guess I am trying to get some kind of specificity.

We have a certain amount of time to answer undertakings. It is an incredible amount of work to go through an entire organization to find anything that already hasn't been produced. And so, you know, the way you phrased the undertaking request is very broad.

MR. RUBENSTEIN: Well, I would say material in terms of its impact on -- if it relates to a material business unit or relates to a material expenditure. I mean, I -- the term used in some other interrogatories where we have asked for benchmarking in the material. The idea is, not insignificant or immaterial.

MR. KEIZER: Right. Actually, if I could just take this away at the break, and talk with Toronto Hydro? And then I can come back to you on the undertaking as to whether we will give that broad an undertaking.

MR. RUBENSTEIN: Okay. I mean, you'll do what you'll

do. All right.

Can we go to 2B-SEC-37. Actually, I understand, can we go to 2B-SEC-44, first? This is the interrogatory that I think you were discussing with Mr. Garner earlier, in which we had asked you to forecast the asset condition based on the work plan that you are providing in this evidence, you provide a lengthy response.

And I will tell you how I interpret it, and you can tell me if I am incorrect of how I interpret it: As I understand for some assets, you have used simplified scenarios to come to it. But there's a lengthy discussion with a significant amount of caveats about your inability really to do it, or what is its meaningfulness. And I just want to -- and at the end, I am just kind of left wondering what I should take away from this response, and the tables that you provide in this response that show that.

Should we take it away that it's not really representative of what the ACA results will look like at the end of 2029, if the plan is approved?

Just help me understand what the bottom line here is of how meaningful those numbers in your view are, actually. And I respect that you tried to answer the question and do your best here, but what should we take away from that.

MR. HIGGINS: I guess, can we bring up table 1 in the response? I think it's on page 5. Yeah. So what we have provided here, Mr. Rubenstein, is the current health scores of our assets in these relevant asset classes as of the end of 2022, which is the basis for planning in this

distribution system plan, as well as the projected future health scores in the second column for HF4/HF5 assets, without investment. So again, this is essentially a scenario where you age out the model that many years, and you get that result.

And then in 2029 as we explained in the notes throughout this interrogatory response, we have applied what we have called some -- a simplistic, kind of, set of assumptions, which is essentially, with the exception of sort of PCB transformers and things that we know about today, essentially what we have done for these asset classes is assume that the worst-condition assets will always get replaced. So you get rid of all your HF5s, then you start getting ready for your HF4s.

And what that gives you is -- we were hesitant to use the term "best-case scenario", because it is not quite that; that would be misrepresentative. But it gives you sort of an outer boundary in a sense of how much better the condition could get if those -- versus the 2029 projection in the middle column, if we were to apply the investments in that way.

The rest of the interrogatory response goes on, I agree, at length, about the various considerations that drive asset replacement decisions that are not purely condition-based decisions, so the complicating factors that are dealt with by an engineer doing a desktop analysis coming up with a scope of work for one of our programs.

So I won't go into those in detail, since they are

already on the record here, unless you would like me to, but that's the idea.

So I am not sure that answers your question, but I can take another crack at it, if you --

MR. RUBENSTEIN: Well, I am just trying to understand because, as you mentioned, there's lengthy, I would say, caveats to the analysis.

MR. HIGGINS: Mm-hmm.

MR. RUBENSTEIN: And they are so lengthy, and I don't mean that in a negative way -- it's a comprehensive response. I am trying to understand at the end of the day, what should I take away from this interrogatory and this -- and really, the table 1 numbers, that this is our best effort at trying to do this, but don't rely too much on this?

MR. HIGGINS: No, I think these numbers can be relied upon. I think we are trying to explain here, if I can just back up: When we go through our integrated or our IPPR process, our investment planning process, it's an options-driven process. And we give direction to our planners to produce investment options based on their expertise, and some of these metrics that are available to them, options that would either maintain risk and reliability or improve it in some strategic way, or actually let it deteriorate in some strategic way that can be managed.

And we then choose investment options for -- our investment plan, basically, from those options.

And so the plan that's been produced and that we've

put forward in the DSP is one that has consideration for the health metrics that are shown in this table, ad this logic that we have put forward here of assessing the current health scores versus the future health scores without investment, and then running this kind of scenario analysis to get a sense of is this the right level of investment to allow us to manage the worst-condition assets and maintain reliability?

That is the kind of analyses that we go through, and that's the analysis that we have attempted to present here.

So there are particular examples that we could potentially go through, after the table, which explain in qualitative terms, based on what you are seeing in the table, and then what can be found in the detailed evidence in the distribution system plan where, directionally, we expect asset health to go. Do we expect it -- do we expect to be able to generally maintain health risk? Might we experience some deterioration that we will need to manage? I think we have articulated that for all the asset classes, if you go further through the interrogatory response.

MR. RUBENSTEIN: All right. Thank you, very much. That's helpful.

In 2B-SEC-37, we asked you about management's tracking progress and capital plans, and what reportings there were. And then we asked you for a copy of the most recent version. And, in 2B-SEC-39, we asked specifically about what you reference, executive performance reports. You point us to 2B-AMPCO-29B and C in those two responses, so

maybe we can pull that up, that AMPCO IR up.

So, in part C, you discuss the monthly investment and operations planning process, and there's a presentation given, as I read it -- do I have that right -- as part of that process?

MR. KEIZER: I think that this is best for panel 2, with the operations folks.

MR. RUBENSTEIN: Is that right? Sorry, I think this was put to this panel.

MR. KEIZER: Yes, I think it shows up on the list of IR's panel, panel 2.

MR. RUBENSTEIN: All right.

MR. KEIZER: The execution folks are on that panel.

MR. RUBENSTEIN: Okay. Can I ask you now to then turn to 2B-SEC-55. This interrogatory asks you a number of questions about third-party contractors, and in part D we asked you about the contractual arrangements with major contractors, and you reference "unit price contract management system."

MR. KEIZER: I think this may also be panel 2.

MR. RUBENSTEIN: All right. Well, then, I apologize. Can we go to 2B-SEC-57. In this, we asked you to provide a table that shows [audio dropout] budget amounts for each year, and you declined to provide it on the basis that it's not relevant and not probative. I'm not sure I even understand that refusal.

Is it the company's position that understanding how the company every year budgets, internally budgets, its

expenditures is not relevant?

MR. KEIZER: I mean, as we stated in the IR response, we believe it's not relevant to this process. I mean, the process here is measuring ourselves relative to the Board-approved that it formed part of the previous rate order and the continuation of the plan into the future, over the proposed rate period.

The changes from year to year with respect to internal budgeting we don't believe to be relevant.

MR. RUBENSTEIN: Does the company internally budget -- you know, the Board approves a capital amount for every year in the last custom IR proceeding. Internally for each of those years, do you -- is the amount that you're working towards that board approved amount, or is it that it ends up being something different?

So, for example, I'll just give you an example. In 2024, this year's budget, there's a budget for the year presumably set by the company; is it the Board-approved amount for 2024 or is that a different number?

MR. MUNDENCHIRA: It is the Board-approved amount.

MR. RUBENSTEIN: That's the amount that you're working for in the company? So the internal amount and the Board-approved are the same?

MR. HIGGINS: Sorry, can we just clarify? When you say "Board-approved," are you talking about the Ontario Energy Board?

MR. RUBENSTEIN: Yes, OEB Board, sorry, not your company internally approved board, your board of directors.

MR. MUNDENCHIRA: The plan that is presented is part of 2AA in the evidence as part of this rate application, is aligned to the latest Board-approved amounts that Toronto Hydro is looking to execute, so it is aligned to what the company is working towards.

MR. RUBENSTEIN: Sorry, that's not my question. Is the internal amount that the company has an internal budget -- first, let's back up. There's an internal amount budgeted amount for every year, correct?

MR. MUNDENCHIRA: Yes.

MR. RUBENSTEIN: And is that the same as the OEB Board-approved amount for that year, or is it different?

MR. KEIZER: Just be careful, though, because I don't think that the OEB approves an amount per year with respect to revenue requirement based on the previous custom incentive rate.

MR. RUBENSTEIN: Well...

MR. KEIZER: Right? So, on an OM&A and a capital --

MR. RUBENSTEIN: We're talking capital. I'm talking capital here specifically. They are the Board-approved five years that was turned into a C factor, et cetera. Is it the same or not?

MR. KEIZER: But just be -- it is a five-year capital envelope that the board approves, right?

MR. RUBENSTEIN: Well, I mean, they approve it for a certain amount of capital for every year that plays into the C factor. That's how [audio dropout] It wasn't one at the end you have to spend this amount of money. I mean,

obviously, it turns into a revenue requirement, so that is specific of which year the amount of capital.

MR. KEIZER: Yes, and then the envelope exists over -- it's over a five year period.

MR. MUNDENCHIRA: And, if I could point you to one of the appendices we have in our evidence, it is Exhibit 2B, section E4, Appendix A. Yes, it's an Excel. While that's being pulled up, that is a comparison of Board-approved capital expenditures versus actual expenditures. However, Toronto Hydro is working towards an approved revenue requirement as far as the 2020 to 2024 rate application. So, essentially, that revenue requirement that Toronto Hydro is working towards is the latest plan that's filed as part of the 2024 application.

MR. RUBENSTEIN: That wasn't my question. So, using the table as you put up here, is the internal budgeted amount -- is the internal approved budget for 2024 capital for the company on the capital expenditures basis, the five-hundred-and-thirty-nine-point -- sorry, the $551.7 million OEB approved for 2024; yes or no?

Or is it some other number?

MR. KEIZER: Well, Just be careful because this is supposed to be a technical conference, not cross-examination, so let's try to colour within the lines here of appropriate TC.

MR. RUBENSTEIN: Well, I'm just -- I'm asking a pretty specific, like, a specific question.

MR. KEIZER: Well, I think they've given their answer,

and I think they've indicated what they do plan on the basis of or what they have provided, so I mean -- and we've already indicated in the IR response that we think the question with respect to the year-by-year internal budget is not relevant, recognizing the five-year capital envelope.

MR. RUBENSTEIN: And you're maintaining that refusal?

MR. KEIZER: We are.

MR. RUBENSTEIN: Okay. Thank you very much. Can we go to 2B-SEC-59. This is with respect -- that's not the right one. Sorry. I apologize. Give me a second here. Sorry, 2B-SEC-42, and this is with respect to your reliability projection methodology. So let me first ask you -- if you go down to line 19 -- this is under the rubric. You're discussing the general overview of the methodology. You say, Toronto Hydro says, "Toronto Hydro modelled defective equipment outages based on asset demographics and included the expected benefits of the utilities 2025 to 2029 planned sustainment investment."

Do you see that?

MR. HIGGINS: Yes, I do, Mr. Rubenstein.

MR. RUBENSTEIN: What does "asset demographics" mean in the context you are using it here?

MR. HIGGINS: It is broadly referring to, you know, the current age distribution of our assets.

MR. RUBENSTEIN: So you use age, not condition?

MR. HIGGINS: For the purposes of this high-level modelling exercise, yes, because we only have condition for

a limited number of assets.

MR. RUBENSTEIN: Okay. Now, you provide information with respect to how the model works, but it's a complex model. We had asked you in part B for the model and your response was, well, we can't provide it to you since it's connected to other databases. Do I have that correct?

MR. HIGGINS: Yes, it's an Alteryx model that is basically embedded within internal systems.

MR. RUBENSTEIN: And you provide us, you say, we can't provide it and then you provide us sort of a visual depiction in the Appendix A?

MR. HIGGINS: Correct, that's basically the model workflow. The tool spits out --

MR. RUBENSTEIN: Which you can imagine is not very easy to understand without the context of that. And so, I have a question. Is there any internal reference documents that you have internally, a guide, some documentation about the model?

MR. HIGGINS: To my current knowledge there's nothing that's been formalized or finalized. There would have been working documents most likely from the development of the model.

MR. RUBENSTEIN: Are you able to provide that?

MR. KEIZER: Sorry, just to be clear, though, Mr. Higgins indicated working -- with respect to the development of the model, but not the model itself in the completed form. I just want to make sure if we're talking about the same things. You may be talking about two

different things, so let's just be clear.

MR. HIGGINS: Yes, I think in terms of the if you're talking about sort of like, a manual or something to the model, there would be some descriptions and notes and some things have been memorandized so that the model can be reproduced, and rerun and handed off in the future, but there's no sort of one central document.

MR. RUBENSTEIN: So, can you provide the former? I mean, this is the situation we find ourselves in, there's a model, it's an important model, a complex model, you can't provide it. So, we're, kind of -- and I recognize the limitations of, obviously, why you can't provide it, so I'm trying to find the next best thing.

MR. KEIZER: We'll look to see if we have, and if it's of a greater technical detail than what's already showing in the flowchart attached in the appendix, then we'll bring that to your attention as to whether it's even helpful for you, but we'll look for those and see what we can produce.

MR. MURRAY: That will be undertaking JT1.5.

UNDERTAKING JT1.5: TO PROVIDE ASSISTIVE OR EXPLANATORY MATERIAL FOR THE ALTERYX MODEL.

MR. RUBENSTEIN: Have you done any internal analysis or review of the models performance itself?

MR. HIGGINS: Maybe you can specify for me, Mr. Rubenstein, kind of, what kind of analysis you have in mind?

MR. RUBENSTEIN: Well, I can think of a couple of things. First, has any third party reviewed the model?

MR. HIGGINS: No.

MR. RUBENSTEIN: Have you yourself done an analysis to back-cast the model to determine, you know, based on what we actually did do in a year, did the reliability projections, are they accurate or not. Have you done any of that analysis?

MR. HIGGINS: We haven't back cast the model as such, however, the model is calibrated so that the level of interruptions is aligned with sort of historical average ranges to ensure that the results are, essentially, reasonable.

MR. RUBENSTEIN: Can you explain exact -- what you mean by that exactly? Like, what do you actually do here? How do we -- let me back -- just ask a higher level question here. How do we know that the model is accurate? How do you know that the model is actually accurate and it accurately forecasts?

MR. HIGGINS: So, with respect to sort of the accuracy, so this model is, to some extent, kind of, an upgrade on the model we would have used in the past, and the goal of the model is, essentially, to relate dollars on one hand to SAIDI and SAIFI outputs on the other, it really is focused on creating that relationship. So, it is a high level model in that sense.

Effectively, the way the model is working is we have failure curves, probability of failure assumptions for out assets, and we're running those assumptions on the underlying asset demographics to determine a number of

failures. Now, the issue with the failure curve is they forecast all types of failures, not just outage -- not just failures that result in outages, and so what we then do is we compare the forecasted results to the historical SAIDI SAIFI results and we do a calibration to bring the two into general alignment. And then, you know, just based on our review of those forecasts, we ultimately determine that we felt like they were projecting a reasonable output, based on the inputs that we put into the model.

MR. RUBENSTEIN: Thank you, can I ask you to 2B-SEC-64. Panel 2 I think someone is going to tell me in a moment. All right. Never mind. Can I ask that we go to 2B-SEC-66.

MR. MURRAY: Mark, just wondering in terms of a time check, and we're scheduled now to take a morning break. But if you want to --

MR. RUBENSTEIN: No, that's a good time to have a break now actually.

MR. MURRAY: So why don't we take a break and come back at eleven o'clock.

--- Recess at 10:50 a.m.

--- On resuming at 11:04 a.m.

MR. MURRAY: Mr. Rubenstein, are you ready to continue your questioning?

MR. RUBENSTEIN: Yes, I am. Thank you very much.

Panel, can we go to 2B-SEC-66? And if we can scroll down to part C? Just to situate us, this is an interrogatory about the system renewal Horseshoe program.

So my first question is we had asked you to provide a breakdown of annual costs included in a table in the evidence based on asset categories in another table.

And, in your response, you say:

"Toronto Hydro has also identified that the volume of cable shown for the 2020 to 2024 period were incorrectly entered as conductor kilometres instead of circuit kilometres.

Do you see that?

MR. HIGGINS: Yes.

MR. RUBENSTEIN: And I just want to be perfectly clear what the difference is.

MR. HIGGINS: So conductor kilometres is just purely the amount of cable. Circuit kilometres would take into account whether it is a three-phase or a single-phase circuit. So the circuit kilometre number will always be lower than the conductor kilometre.

MR. RUBENSTEIN: And so here, you had provided a table in the evidence for 2020 to 2024, which you corrected. How was it shown? Was this in the 2018-0165 application? And it is the same issue there.

MR. HIGGINS: In the previous rate application?

MR. RUBENSTEIN: Yeah. So if I am comparing the various information, because there are similar tables in that, does the same issue arise, where you similarly had made -- this is definitely an undertaking question.

MR. HIGGINS: As a forecast for the -- yeah, we would have to take that back.

MR. RUBENSTEIN: Can you do that? Can you do that?

MR. HIGGINS: Yes.

MR. MURRAY: That will be undertaking JT1.6.

UNDERTAKING JT1.6: TO CLARIFY THE RESPONSE TO 2B-SEC-66C

MR. RUBENSTEIN: Now, my second question with respect to this part is this: Now, you provided the cost breakdown by assets as requested. But when you add up the annual amounts, they are very far off the total costs that were on original table 7.

MR. KEIZER: Sorry, just to interrupt, Mr. Rubenstein. Maybe I can ask Mr. Murray to clarify? There seems to be an issue with the screens. Is that --

MR. MURRAY: Yes, we are looking into it right now. I am wondering whether or not it might be the person who is sharing their screen and sharing the documents. Is that possible? If it's on our end, we are working on it. But I'm just wondering if it's whoever is sharing the document.

That seemed to work.

MR. KEIZER: Thank you.

MR. MURRAY: And I just wanted to check, because I think I saw a message at some point saying that they weren't getting volume online. I just wanted to check, if they were. Maybe if Jane -- sound is on, now. Excellent. We will continue the questioning.

MR. RUBENSTEIN: Would you like me to repeat the question?

MR. HIGGINS: Was there a question? Sorry, Mr.

Rubenstein.

MR. RUBENSTEIN: Sure. Now you provided the cost breakdown. So maybe we can go to the next page, here, just to be clear. And you can see in tables 8 and 9, you provided the total costs by the assets, as requested?

MR. HIGGINS: That's right.

MR. RUBENSTEIN: But when I add those up for those, for the years for 2020 and then 2021 and then so on, those numbers are significantly less than the amounts in the underlying table 7 that you were asked to break down. And I am trying to understand what the difference is.

MR. HIGGINS: Yes. And I am just looking to see. I think we may have discussed an analogous issue in one of the overhead-related interrogatories. But I will just summarize it here.

So essentially what you are seeing here is the major electrical assets that drive the actual program, like, the things that we are targeting for replacement.

What we don't cost out on a unit-cost basis is the civil aspects of these programs, so ducts, cable chambers, tap boxes, things like that. Those assets are estimated on the basis of a ratio. So the planners essentially look at historical ratio between civil expenditures and electrical expenditures, and they gross up the program estimate for the civil assets.

And the reason that we do that is it is very difficult to pinpoint an amount of civil to go with a specific amount of electrical, because it really depends on the specific

geographical situation and the topography of the system and the work that is being done, so it is basically -- that's why there's a chunk of cost that appears to be missing, is there are civil costs that aren't accounted for.

MR. RUBENSTEIN: So the difference, if I was looking at any given year in looking at the table 8 here, and comparing it to the table 7 that's in the evidence, the difference -- I could include a line item that says "Civil Work"?

MR. HIGGINS: That's right. And also subject to check, also, secondary cabling as well would be lumped in with that.

MR. RUBENSTEIN: Maybe you could speak a little bit more about the ratio? How do you -- maybe you could speak again, to that? How exactly do you do it?

MR. HIGGINS: So essentially, it would be looking at the previous -- I would have to check whether it is three or five years exactly, but let's say three years, for the sake of discussion. Looking at the previous three years of investment within the program, and just what is the percentage breakdown between these discrete asset classes that are costed on a unit-class basis and the total cost of the program. And so that ratio would be used to gross up the program from year to year.

MR. RUBENSTEIN: And that's on a forecast basis, because actuals, you would know what the actual costs were?

MR. HIGGINS: Yes.

MR. RUBENSTEIN: Okay. If we can go to 2B-SEC-68?

Just hold on one second, please. Give me a second. I have the wrong reference. All right, -67. If we can go to part C.

In this response, it's very similar; we had asked for a breakdown of the costs by the asset type. In table 1, it talks about updated underground cable renewal costs, broken down by assets categories. So I take it, and we see this again on part D. So I take it that there was an update to the costs, as well?

MS. NARISETTY: Other than the -- I think the only update in here would be the 2023 actuals.

MR. RUBENSTEIN: All right. Thank you very much. If we go to 2B-SEC-69, this is again -- if we go to part E, we asked you a similar question as the others, to break down the costs by the various asset types. Go down to part E. Now, similar to the question I asked you a bit ago, there's a difference between the total costs in table 7 -- sorry, the total costs and what's broken down in table 7 in the original evidence. What's the variance there? Is it civil work again? What are we talking about here?

MR. HIGGINS: Yes, same thing, basically. So, in this case, it would be mostly the cost of secondary services and buses that would not be accounted for. There would be some civil, as well, in these projects. Even though it's an overhead project, there ends up being dips and risers and things that would not be fully accounted for here.

MR. RUBENSTEIN: Okay. Thank you very much. Can we go to 2B-SEC-74. And so we had asked you to provide a

version of a table you had on a Capex basis, on an in-service basis. Do you see that? That's the question, and then you provided that table.

MR. MUNDENCHIRA: Yes.

MR. RUBENSTEIN: And I'm confused with respect to what exactly is being in-service regarding planning and preparation?

MR. MUNDENCHIRA: Yes, the project, there are several phases that will be completed as we go through the project, one of which -- 2027 I believe -- is the acquisition of land. And, as we progress, there are subcomponents of the overall program that will be ready for in-service.

MR. RUBENSTEIN: Well, okay, to 2027 we've got land. I understand that. So is the $6.5 million related to the land?

MR. MUNDENCHIRA: Excuse me.

MR. HUNTLEY: Thank you for the question, Mr. Rubenstein. The assets that are referred to specifically in table 1 categorizes assets that are primarily land and building related, so the building is included in those costs.

MR. RUBENSTEIN: Okay. So, just to be clear, when we talk about planning and preparation, what's being in-serviced in this test period, the 27 and 29, are all related to land and building?

MR. HUNTLEY: That's correct.

MR. RUBENSTEIN: Okay. Thank you very much. Can we go to 2B-SEC-78. So, there, we asked you for certain

information with respect to material capital projects, asked for the name, the program, the original budget cost or if it was included in the application budget, and some information depending on the variance. And you provide the response in 2B-SEC-78. Do you see that?

MR. MUNDENCHIRA: Yes.

MR. RUBENSTEIN: Am I to understand the only material capital projects are those five?

MR. MUNDENCHIRA: For material capital projects, our interpretation is if the individual project was $10 million or more.

MR. RUBENSTEIN: What's your materiality threshold?

MR. MUNDENCHIRA: For the purpose of this response, we have interpreted $10 million. Materiality in general would depend on the specific context.

MR. RUBENSTEIN: Am I correct your materiality threshold is a million dollars?

MR. KEIZER: On a revenue requirement basis, is our understanding.

MR. RUBENSTEIN: I believe that's on a capital expenditure basis, not a material. Is that the position, that it's on a revenue requirement basis?

MR. KEIZER: Yes, that is the position of Toronto Hydro.

MR. RUBENSTEIN: Just to be clear, is that the reason why you responded the way you did, or that's a separate, that's a separate position?

You took materiality to mean 10 million. I want to

make sure I understand the difference.

MR. MUNDENCHIRA: That's correct, Mr. Rubenstein, $10 million was the materiality threshold that was used for this response. It's aligned to a similar question that we have responded to in the last rate proceeding.

MR. RUBENSTEIN: Okay, and, if the board determine that the materiality threshold, a million dollars on -- it was a million dollars not on a revenue requirement basis, how many projects would we be talking, how many projects would make up this table, roughly speaking, obviously?

MR. MUNDENCHIRA: It would be quite significant in the capital expenditures.

MR. RUBENSTEIN: Can you give me a little more colour than just "quite significant," an order of magnitude here?

MR. MUNDENCHIRA: I would hate to make a speculation, but over -- since we're talking about quite a few years, it could potentially be in the hundreds.

MR. RUBENSTEIN: What about at $5 million?

MR. MUNDENCHIRA: It would be difficult for me to give an accurate estimate off the top of my head.

MR. RUBENSTEIN: All right. Well, I'm going to ask you to provide a revised response to 2B-SEC-78. "Materiality" in that context is all projects that had a budgeted capital expenditure amount of $1 million or more.

MR. KEIZER: Sorry, just one moment, Mr. Rubenstein. I guess this thing we're struggling with is that materiality -- I mean, in our view, materiality relates to revenue requirement. Something that's a million dollars in

capital expenditures, you know, in terms of overall revenue requirement is not a significant amount relative to even a million dollars. As well, I think that there are interrogatories which indicate the number of projects, which I think 2B-AMPCO-29, for example, there's hundreds of projects that actually Toronto Hydro does, so I'm not quite sure I understand. That's a significant amount of work, number one, for a small amount of revenue requirement for some of those projects, and so I guess I struggle with the overall relevance of the complete probative value of breaking down every project that may have a million dollars attached to it.

MR. RUBENSTEIN: Well, let's take that separately. With respect to the position on what the million dollar materiality threshold, I think our view is it's not with respect to the revenue requirement. With respect to -- and the relevance is obviously clear. We're assessing the capital execution of the company compared to its budgeted amounts.

Just to be clear, the more detailed information is only with respect to projects that have a variance, a plus or minus 10 percent. I'm not asking for a detailed assessment of any amount.

And with respect to the amount of work. Well, that's why I asked what is a 5 million dollar error, how many projects are we talking about at that range. I'm just trying to understand where the -- what, actually, the breakdown looks like when you get to differing, you know,

buckets of size?

MR. KEIZER: Yes, I think at this stage, Mr. Rubenstein, we still struggle to see what the overall relevance of that is, so. But let us take it away at lunch, and see if we can talk about it further. But I do have concerns with respect to the total volume of work, given we'd be talking about hundreds of projects.

MR. RUBENSTEIN: Can we turn to 2B-AMPCO-33. Here you were asked about various studies that you had undertaken. Just one or two I have a question about. Maybe we can flip to the next page. The one I'm interested in -- sorry, maybe I can just -- in the last page it talks about the preventative maintenance optimization overhead switches, and it talks about work that done with Metsco. Do you see that?

MS. NARISETTY: Yes.

MR. RUBENSTEIN: And then it talks about conclusions and recommendations. And my question is: Have you implemented that? Have you implemented a variable cycle for switches based on the risk category?

MS. NARISETTY Subject to check, I believe it's part of our application that's in front of you.

MR. RUBENSTEIN: So, that's a yes? Subject to check.

MS. NARISETTY: We haven't implemented. It's part of the 2025 to 2029 rate term.

MR. RUBENSTEIN: Okay. So, you haven't implemented it yet but you plan to for purposes of the upcoming rate term?

MS. NARISETTY: Subject to check, yes.

MR. RUBENSTEIN: Now, can I ask you about the distribution assets failure curve study? Can I just ask you if you can provide a little bit more colour of what you were asked to do there?

MR. HIGGINS: Yes. So, we as part of our longer term analytics strategy, we are looking to develop some more sophisticated probability to failure based kinds of tools for predicting future performance, you know, algorithmically creating potential project candidates and things like that that will drive efficiency and improvements. And as part of the long lead-in to eventually doing that, we wanted to explore, with an expert, what kind of failure curves we might be able to squeeze out of our current failure data sets if we apply some more advanced statistical methods and some cutting edge techniques to that data. So, this was a research exercise to see what kind of outputs get using our own failure data.

MR. RUBENSTEIN: Can you provide that?

MR. HIGGINS: Yes.

MR. MURRAY: That will be undertaking JT1.7.

UNDERTAKING JT1.7: TO PROVIDE MORE DETAIL ON THE DISTRIBUTION ASSETS FAILURE CURVE STUDY

MR. RUBENSTEIN: Can I ask you to go to 2B-AMPCO-39. And in part B you were asked to provide the number of work request cancellations per year. Do you see that?

MS. NARISETTY: Yes.

MR. RUBENSTEIN: Now, from my eyes it looks like very

high number of work cancellations. Can you speak to that, quite a high amount of work that you ultimately end up canceling? What's driving that?

MS. NARISETTY: So, the cancellations may occur for a number of reasons. And the work requests that are -- that form the input to the reviews that are conducted that ultimately may lead to a cancellation are all-inclusive. And when it comes to actually allocating the work, issuing out the work, there's a number of checks and balances that we have in place to make sure that, you know, it's work that needs to be done in a short period of time.

So, for example, an engineer could review the results from an inspection that would come back that may say perhaps there is some work required, and they may decide that immediate work is not necessary.

Or our execution management team can look at the work and say that there is already an existing project here, and hence the work is not required to be done in that short period of time.

MR. RUBENSTEIN: Thank you very much. That's helpful. Can I ask you to go to 2B-Staff-138B. So, here you were asked in part B how does Toronto Hydro prioritize pole replacements, given that it replaces poles that have different health indices. And you talk about how you replace forms in HI4 and HI5 condition, and then you provide some colour about how you make a determination of how that works, based on, you know, focusing on the system where there's customers' failure is high, you know,

historical poor performance, et cetera. Maybe you just can talk about how in practice what this actually looks like when you're determining which of the poles to do, poles to replace?

MR. HIGGINS: I'm just considering whether it's worth maybe directing back to SEC-44, which I think does give some more colour around those considerations.

MR. RUBENSTEIN: Let me rephrase the question.

MR. HIGGINS: I'm trying to think of a concise way to respond here, yes.

MR. RUBENSTEIN: You know, there's a -- a lot of the answers are very -- you know, you're providing a sort of general view. I'm just trying to understand, practically speaking, you know, you have a bunch of poles in H4 and H5, how in the company, when the engineers or the planners are determining which poles, what does this look like when you're making that determination?

MR. HIGGINS: So, it is -- our particular planning paradigm because of the nature of our system is programmatic in nature and very bottom up in nature. And so, what I mean by that is, the engineers are assigned and become experts in their particular regions of the system and the groups of assets that exist within those regions, so Horseshoe west and Horseshoe east, et cetera. And they're looking at trends and performance, they're looking at clusters of risk. They're looking at various obsolescence issues, plans that they have long term to convert certain parts of the system to different standards,

a number of different drivers. And ultimately through a desktop analysis, they're piecing together information to determine what is the next focus area for a project.

And that would be the typical, kind of, scope of work that we would do is, we've identified a section of a feeder or a particular neighbourhood or a couple of streets, or whatever it is, that requires coordinated intervention, and the assets in that area are then dealt with as a group. And so, one of the drivers of choosing one of those areas would be the number of HI4, HI5 assets.

In other instances where we have one-off poles that are sort of, an isolated situation, they're condemned, perhaps, and they require more urgent repair on their own, we may do a spot replacement project if we feel that there's enough of a lead time to do so, or if it's truly an urgent issue we may deal with it reactively, so that's how a number of, say, HI5 poles would be dealt with, is through a reactive program. So, there's different ways that we get at it.

MR. RUBENSTEIN: There's a lot of things that go into the assessment, as I would I take it you determine, and you have different planners that focus on different parts of the city, correct, right? They focus on different parts or making the decisions that are different parts of the city. Correct?

MR. HIGGINS: That's right. But then they're following a set of sort of established principles that make up our planning paradigm.

MR. RUBENSTEIN: I think you're getting to my question. But it seems to me, listening to how you do current planning, there's a lot of different considerations, there's a lot of judgment that is required, individual judgment that's required, which -- so how do you ensure that different planners focusing on different systems are actually -- you know, are taking in all that information and coming out with what would be a sort of a similar outcome? A similar type of project is being done in area, similar type of poles in the same -- you know, of this type of reliability issues and so on. How do you determine that? Or how do you ensure that?

MR. HIGGINS: Well, I will just clarify that the -- I mean, the character of any given project in terms of how exactly it is dealing with the particular challenges on the ground can vary significantly, from scope to scope. Some overhead system renewal programs may in fact be more focused on, at the end of the day, sort of redesigning that part of the system, if it turns out that's the best solution to dealing with that particular ageing part of system. So the actual scopes can vary significantly in terms of how they address assets.

In terms of how the overall process is governed, again, it's a bottom-up process, and so the planners are empowered through training and job shadowing and their own experience to become experts in the system. Over time, they get feedback and then, ultimately, their managers are accountable for ensuring that consistent principles are

being applied, and that the right scopes are going into our scope pipeline for execution at the right time.

MR. RUBENSTEIN: And in Part C of the response, you were asked about the -- well, you were asked about the economic trade-off between value to customers. And then in the response, I believe it's part C, you mentioned -- just hold on one second. This is on page 3. You mention about the value framework that you are going to be implementing in the next -- I believe it's, and maybe you can correct me, which year? It's within the next planning cycle, correct? Do I have that correct?

MR. HIGGINS: I'm sorry, I don't know if it's just the fan blowing behind me, but I couldn't quite hear.

MR. RUBENSTEIN: Sorry. You talk about the value framework that you are planning to implement, and I was trying to recall exactly the timing; I think it is for the next planning cycle, that you are going to have that in place?

MR. HIGGINS: Yes. Our goal right now and we are on track is to have it ready for the beginning of the next planning cycle, next year. Yes.

MR. RUBENSTEIN: And I believe it is the Copperleaf system.

MR. HIGGINS: Yes.

MR. RUBENSTEIN: And so, as I understand the Copperleaf system, probability and consequence of failure, and it is also -- you know, it makes a determination, if you do the work versus you don't do the work, it changes in

the risk levels. Correct? Is that your understanding, at a high level?

MR. HIGGINS: Essentially, yeah, you are influencing changes in the risk levels, which is then computed in terms of value achieved. Yes.

MR. RUBENSTEIN: And it allows you to prioritize projects across different categories of spending programs, one of the benefits of the system. You can compare a project in the Horseshoe -- you know, at a Horseshoe project, a Horseshoe overhead project with a downtown underground, which one would you have to -- which would be, if you had to choose one, which one would you do? That sort of idea. Correct?

MR. HIGGINS: You can. Yes, you can do that.. Whether or not that's a direction that ultimately we end up going, that will be something that we determine through sort of using the tool over time. Because the further you get away from like-for-like projects, the more you are kind of artificially comparing values. But it's certainly possible. Yeah.

MR. RUBENSTEIN: Well, so I guess I am -- you are getting to where I want to ask you about: You are going to implement this during the rate -- imagine the Board approves your budget and your application as filed. So you have projects, you have forecast units and dollars.

But now, you are implementing a new system in the next planning process that takes place during that plan. Are we going to come back in 2029 and you might have spent the

same amount of dollars that the Board gives you, but the mix of projects is just totally different because of the change in the system.

MR. HIGGINS: I would not expect it to be the way you characterize it, totally different, Mr. Rubenstein. It may change. But one caveat I will say is we -- getting a capital project executed is a very long lead-time activity. So the current work program for 2025 and part of 2026 is already scheduled. And those projects have not been subject to this new kind of optimization tool.

So the effects of the tool likely going to begin to, you know, influence the program until around -- sometime in 2026 and 2027. If the actual mix of program -- now, one thing I will just go back to is this is not a project-based distribution system plan. We only have so many projects to base the plan on.

However, to the extent that this tool results in maybe a different mix of program spending, that would be, arguably, because that tool has helped us identify, you know, where to direct the capital funding in an even more sort of granular, sophisticated way.

MR. RUBENSTEIN: Is it your expectation that it will affect materially, let's say materially, the program, the mix of program spending.

MR. HIGGINS: No. It would be speculation at this point to sort of try to put a quantum on it. No, I would not expect that it would be a material difference.

The distribution system plan is developed using kind

of parametric estimating approaches. We are looking at relationships between spending and outcomes. And the plan that we put in front of the board is one that we think is the right spending to achieve the outcomes we have articulated.

So I don't expect that the program spending will change dramatically as a result of this new tool. I think the new tool will help us ensure that we are doing exactly the right projects to achieve those outcomes and hopefully, over time, that starts to make the achievement of those outcomes a more cost-effective endeavour.

MR. RUBENSTEIN: Yes. Just to clarify it, I wasn't asking the question that you would do work that you shouldn't do. But it may just change -- as you are mentioning, it's kind of -- I think the goal of the project to implementing it is you will do the -- like, you will pick the best projects comparatively, right? And I am just trying to understand if, when we come back in 2029, are all the unit -- you know, you forecasted unit numbers you are going -- for all the programs and all that. Is that really going to -- is it going to look all -- is it going to look different?

MR. HIGGINS: No, we don't expect it to result in -- we don't expect the tool to be a material driver of major changes in the programmatic kind of number of units that we have to do.

MR. RUBENSTEIN: It is just going to focus on which of those, you know, if you have -- which -- I forget; I don't

know what the Toronto Hydro lingo is these days, which jobs or which programs within -- which projects within a program change, which ones you do.

MR. HIGGINS: That would be the biggest effect, I would say. Yes.

MR. RUBENSTEIN: Thank you, very much. Can I ask you to go to 2B-Staff-212A.

MR. HIGGINS: Sorry, what was the reference?

MR. RUBENSTEIN: 2B-Staff-212A. And if you flip to the next page, you talk about the primary driver of cost increases across all asset classes was price inflation. And you talk about reflecting commodity costs from that period, you talk about copper and aluminum prices and the large swings we saw

And when I raised that question, it raised sort of a broader question for me which was, you know, it's one thing that there were swings in commodity prices, but I couldn't really see anywhere in the evidence where we see what is the change in your actual material costs, right?

So transformers: I think transformers, there was -- transformer costs went up over time. And I couldn't find anywhere that showed, you know, over time where -- for each of the major asset classes, what were the actual increases in the underlying cost of the asset to Toronto Hydro? And how that -- and what that looks like for 2025?

And so maybe I can ask you to do this by Undertaking: Are you able to provide a table that shows for each year between 2020 and 2023, the actual cost per major asset that

you purchase?

So kilometre of underground cable, pole top transformers, to show the price inflation for those materials? And then can you show us what that looks like on a forecast basis, for 2024 to 2029?

MR. HIGGINS: I don't know if this will be fully satisfying, Mr. Rubenstein, but if I can take you to section D2 of the distribution system plan? At page 14, we did provide some examples. And these are trendlines. So we can provide some more detail.

But we did provide some examples of how costs went up for some of our higher usage cable types, as well as our higher usage transformer types, both overhead and underground.

MR. RUBENSTEIN: Well, then, I will ask this question, and I will use this as a representative here. Are you able, first, to provide this in a tabular format, not a chart, and then can you provide the forecast that you're utilizing for the application, then, and the numbers for 2024 to 2029?

MR. HIGGINS: So we can do the tabular part of this. With respect to the forecast, subject to check, I'm fairly confident that that likely would not be possible because the way that the programs are estimated are on the basis of, like, ISA unit costs for major asset classes. So there's not a specific material cost assumption. And a given project may, you know, use a number of different subtypes of assets with different material costs, so, yes,

I don't know that that would be possible. Like, we didn't base the forecast, I guess is what I'm saying, on those kinds of unit costs.

MR. RUBENSTEIN: Well, do you forecast what these costs are going to look like, internally? Put aside how you've done the build-up of the capital plan; internally are you forecasting what these major asset costs are going to look like?

MR. HIGGINS: Yes, no, we wouldn't -- we don't have those forecasts.

MR. RUBENSTEIN: You don't do the forecasts? You're not forecast -- you don't internally forecast those sorts of things? I'm just clarifying your response.

MR. HIGGINS: No, not over this time horizon, no.

MR. RUBENSTEIN: Well, I'll take the undertaking for the tabular response to this.

MR. HIGGINS: Sure.

MR. MURRAY: This will be undertaking JT1.8.

UNDERTAKING JT1.8: TO PROVIDE THE DATA AT PAGE 14, SECTION D2 OF THE DISTRIBUTION SYSTEM CODE IN TABULAR FORMAT; TO CLARIFY TIME LAG BETWEEN TIME OF ORDER AND TIME OF INSTALLATION.

MR. RUBENSTEIN: I just want to be clear. These represent the time of purchase, the year of purchase, correct? Or is it the...

MS. NARISETTY: Yes.

MR. RUBENSTEIN: Okay, so let's use a top usage. Let's use the transformers. It's 2023. You buy a

transformer, and the prices are shown. When would -- that transformer would be used for a project when? When you take into account lead time to order, you know, using your inventory first, when would a -- if I buy something in 2023, it's going to be, that transformer will be used in the field when?

MS. NARISETTY: So, yes, there may be a lag between when we purchase the equipment versus when it is actually issued out and installed, And that's where, again subject to check, these numbers are a moving average, because we do regularly purchase equipment and regularly issue it out and regularly install it. So it's a moving average.

MR. RUBENSTEIN: Okay. So, then, it's not representative of the average price of -- let's just take top usage cable. I'm looking at the first line, 9662955 cable triple X. That doesn't represent the cost of the purchases made in 2023, the average purchases that were made in 2023?

MS. NARISETTY: On a representative basis, yes, but, like I said, we procure equipment on a daily basis, so that's why we utilize a moving average type of formula, to take into account, you know, everything that is purchased over a quarter, over six months, over a year. So this is representative of what was the price for these assets in those particular periods.

MR. RUBENSTEIN: But let's say you purchase a project, well, mid-year of 2023. July 1st, Canada Day, you make a purchase. When -- if you can, give me a sense of, like,

when would that be used in the field. Because, as you know, when it's installed, that's when it's in-serviced. I'm just trying to understand the time. What are we looking at here?

MS. NARISETTY: It would vary project to project. So, if it is a very high-usage piece of equipment, you know, it may get issued out, you know, within the week. Sometimes we may be purchasing equipment, you know, to replace a critical spare, in which case it could sit in our warehouse for some time, until there's a failure in the field, and then it gets issued out. So it's hard to say, you know, when it would actually get issued out. It varies highly project to project.

MR. RUBENSTEIN: Well, first you have to have delivery. Then it's -- so there two steps.

MS. NARISETTY: Mm-hmm.

MR. RUBENSTEIN: So maybe in your response to your undertaking that you just gave you can give me a sense for these, which are your top-usage equipment, what is the lag between the time of ordering, which is I think the price point -- you can correct me if I'm wrong there -- and when it would be in the field, in terms of installed somewhere. Is that something you can do by way of undertaking?

MR. KEIZER: Just to be clear, though, because I'm assuming these numbers include many pieces of assets, right, so we don't want [audio dropout]

MR. RUBENSTEIN: I'm talking about an average. I'm just talking about a general sense. I don't need, you

know, 4.23 days. I am just trying to get a sense of what we're talking about. When you order that cable that I had referenced, it's going to take time to be delivered, and then you have something in inventory. When are we looking at that that shows up in the field and get installed?

MR. KEIZER: Yes, the thing is, what the witness is saying is it turns over all the time, right; that's why you have a moving average. So it's not like you've got that piece, and that piece is earmarked for whatever.

MR. RUBENSTEIN: No, I understand, but it the same sort of moving average of when it would show up in the field to give me a sense of what we're talking about here.

MR. KEIZER: Why don't we do it this way, that -- sorry. Just a moment. You go ahead. That we -- that Toronto Hydro consider whether they could provide that information? If there's something that they can that's meaningful, they will, but, if they can't, they'll explain why they can't.

MR. MURRAY: Just for clarity, that would be added to 1.8.

MR. RUBENSTEIN: Can I ask you now to turn to STAFF-238. So the question asks about contributions to Hydro One during the period, the 2025 to 2029 period. Do you see that?

MR. HUNTLEY: Yes, I do.

MR. RUBENSTEIN: And as I understand the last -- I just want to make sure I understand the last line, the true-up costs, where you have included an amount of true-

up. Just to be clear, I take it that those are, that is a collection of various true-ups making sort of a net calculation of all the true-ups that you have to make in any given year with respect to pre-2025 Toronto Hydro contributions to Hydro One?

MR. HUNTLEY: Could you repeat the question, Mr. Rubenstein? Please clarify.

MR. RUBENSTEIN: I just want to make sure I understand what the true-up costs line is. It is the last line in the table. And I take it that, when you are discussing true-ups in the context of this question, those relate to various true-ups on previous contributions you've had to make to Hydro One pre-2025, and those would include multiple different true-ups you may have to make in a year, plus or minus, they may have to pay you, and it's a net number. Is that right?

MR. HUNTLEY: For the earlier years in the forecast, 2025, 2026, and 2027, that would be entirely accurate. They would be for projects that were -- require contributions prior to 2025.

MR. RUBENSTEIN: But, for the later years, '27 to '29, how is that different?

MR. HUNTLEY: As you can see in the categorization column, there is mention there of "construction and/or true-ups costs." They are projects that are executed in the rate period that will also require true-up costs, or attract true-up costs, so those will be later year charges that are reflected in '28 and '29.

MR. RUBENSTEIN: But '25 and '26 contributions will have later true-ups?

MR. HUNTLEY: Projects that are executed in the rate period, meaning shorter term projects, can attract construction true-ups within the rate period. Those would be funded from that line as well.

MR. RUBENSTEIN: And I take it -- I mean, if you know now you're going to have to make a true-up for a project that hasn't happened yet, I take it it's because you had agreed to the contribution previously?

MR. HUNTLEY: When it comes to -- it depends on the type of true-up we're discussing. Load true-ups are generally easier to forecast than construction true-ups. The majority of the true-up costs that are reflected in that line are load true-ups. So, what we're -- so, to go back to your initial assertion, that the projects that are going to be reflected in that particular line item would have been executed prior to 2025 is still correct. But what I am attempting to indicate to you, that construction true-up costs can be reflected in the later years for projects that are initiated in 2025, that are construction related and complete in the rate period.

MR. RUBENSTEIN: All right, thank you very much. Can we go to 1B-Staff-89. Can we go to part G. Go down to the bottom of the response. So, just actually the question just so we can situate ourselves here. Staff had asked you about the factors and considerations that led Toronto Hydro to the conclusion that the shared savings mechanism

incentive options were not sufficient to the level playing field between the LDR program and the load transfers. And If you go to the bottom. In the last sentence you say:

> "Compared to the forgone revenue of 37.2 million and the operational and market risk and complexity associated with successfully delivering of the LDR program, Toronto Hydro did not find the shared savings outcome acceptable."

Do you see that?

MS. MARZOUGHI: Yes. Sorry, can you hear me?

MR. RUBENSTEIN: Can you provide some more insight on what you meant by that it wasn't acceptable?

MS. MARZOUGHI: Sorry, Mr. Rubenstein. So, the question is with respect to Toronto Hydro's decision not to use the shared savings mechanism for the performance incentive?

MR. RUBENSTEIN: No. The question -- your response says Toronto Hydro did not find the shared savings outcome acceptable. And I just want to understand if you could provide a little bit more about why you didn't find it acceptable.

MS. MARZOUGHI: If we can just take a step back. The decision to utilize the score card metric for the performance incentive for the non-wires program is situated just within our broader use of the score card mechanism to measure outcomes and within the performance incentive mechanism framework. Now, in terms of why we didn't go with the shared savings, and the statement that you're

referencing there, that we did not find the shared savings outcome acceptable. It's with respect to putting the non-wires program on a level playing field to the conventional options for system planning. And that that using the shared savings mechanism wouldn't do that.

MR. RUBENSTEIN: And so, I take it, then, what you're say is the principle behind it, correct me if I'm wrong here, is that you needed to find a mechanism that completely levels the playing field, the equivalent of [audio dropout] a conventional wire?

MS. MARZOUGHI: What we would put forward is, yes, a mechanism that we believe doesn't completely level the playing field, but does put non-wires solutions -- it puts non-wire solutions in the same realm as making a capital decision.

MR. RUBENSTEIN: What do you mean by same realm?

MS. MARZOUGHI: Like, similar. It's not exactly equal, but it brings it to a similar consideration.

MR. RUBENSTEIN: Okay, thank you very much. Can I ask you to go to 1B-SEC-21. Now, this question is asked, so I think all of the, all the panels, so I'll try first with you guys. So, in this question we had asked you, we're just trying to understand how the change in the capital budget would impact the PIM targets. And so, we had sort of given you a hypothetical and three scenarios that the board may order in a decision, and how that would affect the -- let me just stop. As I understand the proposal, after the Board -- as I understand what you're proposing,

is after the Board's decision, you will assess the decision, and then come back with, assuming there's a reduction of some sort, you'll propose differing PIM targets that take into account the impact of the decision. Do I have that right as a high level?

MR. HIGGINS: I do think we're getting in, maybe, to some procedural elements that might be better dealt with by panel 3.

MR. RUBENSTEIN: Well, I want to ask you the next step. So just, am I far off of what the proposal is?

MR. KEIZER: I think that's a reasonable premise.

MR. RUBENSTEIN: Okay. And so we asked you, here's some scenarios, what would it look like? I would imagine this is what the board ordered, how would you take that into account? So we can assess the proposal to do that.

And the first thing you mention is that Toronto Hydro is unable to forecast PIM targets on the basis of the scenarios outlined above. And you, kind of -- you provide some explanation, but I'm just confused by that, because imagine the board provided you with that decision. You're going to have to do it, so help us.

MR. HIGGINS: Yes, the issue maybe to just help clarify the response a little bit. The issue here is not so much whether it's doable in and of itself within a certain timeframe, but in the context of the interrogatories process, where, you know, we're dealing with I think it's 45 hundred individual part questions. Doing this kind of a strategic exercise within the company

to come to a consensus view on what the re-forecasted PIMs would be under multiple envelope scenarios was not feasible within that timeframe.

MR. RUBENSTEIN: Okay. So, help us, what I assume help the Board, is trying to understand the proposal. Okay? We're trying to see what this would look like, how you would deal with it. So, maybe you can help me from a process point. Get the board decision, and it says something like reduce capital expenditures by X percentage. Walk me through how you're going to go about the process of adjusting the PIM targets, or at least for this panel those that deal in your categories, in your areas of responsibilities.

MR. KEIZER: Well, Mr. Rubenstein, if I can point out to you that, and the interrogatory, I think the response also includes the fact that the question is related to capital expenditures, but the other concern is that it's, kind of, an incomplete scenario, because it doesn't consider operational funding, so it doesn't include the OMNA funding, which would also be part of the consideration with respect to that, to PIM.

MR. RUBENSTEIN: Let's just assume that the only reduction was on the capital. Right?

MR. HIGGINS: Yeah. I mean, it's not complicated; it's just a time-consuming process. So we would need to iterate through some different scenarios, leveraging things like our reliability forecasting model, but also all the other judgment that goes into determining the right level

of investment, and figure out what kind of trade-offs we would want to make within the overall investment plan, at the proposed level of investment, and come to a new strategy where we would have to determine which outcomes are we going to sacrifice, by how much.

And that's just an iterative exercise that requires a lot of input and a lot of stakeholdering, and -- but it is something that can be done within the proceeding. It just couldn't be done for this interrogatory response.

MR. RUBENSTEIN: And then you do provide some information. It's a lengthy interrogatory, so you provide this. But you are looking at it, as I understand it, at the scenario 3, the 30 percent reduction?

MR. HIGGINS: The tabular result?

MR. RUBENSTEIN: No, when you go -- yeah. If you go through the rest of the response.

MR. HIGGINS: So it wasn't -- oh, yes, so the total -- that's right. So what we set out to do here, to be helpful, was demonstrate the sensitivity of the PIMs to different programs that are the more sort of materially related programs to the PIMs.

And so what you see here is basically if we were to zero out particular models, or particular programs -- so, for example, a total reduction to the Horseshoe renewal programs, this would be the total effect of that change. And then, when you combine all of the investments that we have zeroed out through these different options, you end up with something that is close to 30 percent of the overall

capital program.

MR. RUBENSTEIN: But you didn't provide one at the 10 percent or the 10 percent? You picked the 30 percent one.

MR. HIGGINS: No, because again, to do that, we would need to make actual determinations on what the program would look like and which outcomes we would prioritize over others, and which risks we would prioritize over others.

So, instead of doing that, we offered a number of different examples. One could total up the numbers as one wishes and come up with something closer to 20 percent. But we just caution that that's not a plan; it would just be a hypothetical.

MR. RUBENSTEIN: Okay. Thank you, very much. Can I ask you to go to 2B-Staff-172B?

MR. KEIZER: Take a moment. I know we are coming up to the lunch break. I just want to clarify, when you were thinking of breaking for lunch?

MR. MURRAY: After Mr. Rubenstein's next question, I was going to ask him the exact same question, where he was at in terms of things.

MR. RUBENSTEIN: I am almost done, so...

MR. KEIZER: If you are almost done, maybe we should let you have a restful lunch, Mr. Rubenstein, and see if you can finish it.

MR. RUBENSTEIN: Well, maybe let me ask this one question, and then we can -- I am fine with that.

In part B of this response, you were asked:

"Has Toronto Hydro identified unacceptable

reliability trends relative to its historical performance or its peers? Please explain."

And then in the response, and you say this in the first sentence, you say:

"Toronto Hydro views its reliability performance as acceptable both in comparison to its historical data and in competitiveness amongst its peers."

I just want to be clear, I just want to ask you just so I can clarify, when you are using the term "peers" in the context of this, is it peers [audio dropout] Clearspring report analysis? Who are peers in this context?

MR. HIGGINS: I think this was intended to be more of a general statement, so it could -- you know, it's both.

MR. RUBENSTEIN: Both? I think I only gave you one, so I am -- one grouping. So is it --

MR. HIGGINS: Sorry. Clearly, I got ahead of you. Yeah, the Clearspring would have been part of this, as well as just looking at the electricity distributor scorecard in our Ontario counterparts.

MR. RUBENSTEIN: Okay. Thank you, very much. Maybe we can take the lunch, now.

MR. MURRAY: We will take the lunch now, and we will come back -- let's some back at one o'clock.

--- Luncheon recess taken at 12:10 p.m.

--- On resuming at 1:07 p.m.

MR. MURRAY: Thank you. Welcome back. Mr.

Rubenstein, before you proceed, I understand you have maybe one or two more questions. I was wondering if you can give an update on those two outstanding potential undertakings that you and Mr. Keizer were discussing over lunch.

MR. RUBENSTEIN: Yes, I believe there are two. One is with respect -- I'll call it broadly production of reviews or assessments that are not, or audits that are not included in a number of other interrogatory responses. And the second one is the response, a response, to interrogatory -- we had asked a follow-up question on 2B-SEC-78 with respect to material capital projects. We're still having some discussions, and, hopefully, we can get to a conclusion and deal with it first thing tomorrow morning.

MR. MURRAY: Thank you for that update, Mr. Rubenstein. I hand it over to you for any further questions.

MR. RUBENSTEIN: I just have two small and hopefully quick questions if we can go back to 2B-SEC-66C. So, if you recall our discussion, we had asked you to take the capital numbers in the application and break them down into the asset categories that were in another table. And part of that response was that there was an update to the -- there was a change -- once when you were doing the response, you noticed that there was an error in the number of units in certain years, and you provided the corrected numbers. They're in the updated table. Do you see that?

MR. HIGGINS: Yes.

MR. RUBENSTEIN: I just want to make sure, then, in the evidence, the table 7 in the evidence that has the total dollars, is that correct?

MR. HIGGINS: Yes.

MR. RUBENSTEIN: And, similarly -- maybe you don't need to pull it up -- in SEC-69, you did a similar thing, where you had to update upon your review of the situation, and during answering the question, you noticed that there were some errors in the unit cost measurement. Is the dollars, the budgets in the underlying evidence, did that also need to be corrected or not?

MR. HIGGINS: No, the dollars are all consistent.

MR. RUBENSTEIN: All right. Thank you very much, panel. Those are my questions.

MR. MURRAY: Thank you, Mr. Rubenstein. Next on the list is AMPCO, Ms. Grice.

EXAMINATION BY MS. GRICE:

MS. GRICE: Thank you very much. Good afternoon, panel. I have less questions than I originally thought, in part because they've already been asked, but, based on your discussion also with Mr. Rubenstein, I realize some of my questions are better suited for panel 2, so I will not be using all of my time.

Okay. The first question I have is with respect to 2B-AMPCO-15. I want to look at the table there, table 12, which is a standard labour-rate calculation for the power-line technician position. My understanding is Toronto Hydro allocates labour costs to projects using time sheets,

based on safe for, in this example, for the power-line technician position; when the project is being undertaken, the costs would be applied to the project as the labour costs are incurred. Is that correct?

MR. MUNDENCHIRA: Yes, that's correct.

MS. GRICE: All right, and then you've got a standard labour rate for every role in the organization, correct?

MR. MUNDENCHIRA: Yes.

MS. GRICE: Okay, so I just have just a question about 2025, the forecast, and how those numbers are derived. So, the total compensation cost, is there a link to appendix 2-K with respect to those costs? Or maybe you could just let me know where the $12.4 million comes from.

MR. MUNDENCHIRA: Ms. Grice, while there is a relationship to appendix 2-K, appendix 2-K is on an aggregate basis; it doesn't have the same level of detail to the labour type.

MS. GRICE: Okay, but appendix 2-K includes the 12.4?

MR. MUNDENCHIRA: Subject to check, yes.

MS. GRICE: Okay. And then, just in terms of total working hours in a year, available working hours, what goes into that number?

And I guess what I'm thinking is it's obviously number of positions times number of working hours in a year, but is overtime, are overtime hours, included in there? Maybe, if you can, just speak to what is included in total working hours.

MR. MUNDENCHIRA: Yes, if you can give me a moment, I

will point you to a reference. The reference is Exhibit 2A, tab 4, schedule 2, S.1.1 on page 1. So, here, we have described the methodology used for calculating standard labour hours, in s.1.1.

MS. GRICE: Okay, so, just in the first one, total working hours in a year, is overtime factored into that or is that separate?

MR. MUNDENCHIRA: I need to subject to check that, but I believe it is.

MS. GRICE: Okay. And then I just have a question because I see that here's the definition and things are subtracted off to arrive at the final total available hours. And, if we can, just look at the line -- let me see here. It's row 4, which is "time not spent working on a specific operating or capital project." I just had a question about that.

Will you take it subject to check that, for the years 2020 to 2023, about 7 percent of the time is in this category time not spent working on a project, which I believe has to do with training and safety meetings and down time? But then, when we get to 2024 and 2025, it's closer to 13 percent, and I just wondered what, what's accounting for that difference in time not spent working on a project?

MR. MUNDENCHIRA: I'm afraid I do not have that information in front of me right now, but I can undertake to look into it.

MS. GRICE: That would be great. Thank you.

MR. MURRAY: That will be undertaking JT1.9.

UNDERTAKING JT1.9: TO CLARIFY AMOUNTS FOR THE CATEGORY, DIFFERENCE IN TIME NOT SPENT WORKING ON A PROJECT

MS. GRICE: Okay. And then, just turning the page, I just have a question on part B of the interrogatory response. And this was asking questions on the on-cost rate for material handling. And, again, my understanding is, as materials are used, the costs then are directly charged to projects as they're incurred. Is that correct?

MR. MUNDENCHIRA: As the materials are issued to a specific project, yes, that's when it shows up on the project.

MS. GRICE: Okay. So, in table 2, you've got a material throughput row that has dollar amounts in each year, and, for 2025, it's $165.1 million. Is that amount, has that, is that built into the OM&A budget for 2025? Are those your projected, forecast, material costs for 2025?

MR. MUNDENCHIRA: It is not specifically OM&A. It can include capital and opex projects.

MS. GRICE: Okay.

MR. MUNDENCHIRA: But the underlying assumption, yes, is the forecasted programs in capital and OM&A.

MS. GRICE: Okay, so would those, would that cost include, you know, the cost of poles, transformers, cable, all of those types of materials, as well?

MR. MUNDENCHIRA: Yes, correct.

MS. GRICE: Okay. And then the first row you've got

eligible procurement and warehousing related operating expenses. And I just wanted to compare that to numbers that you had in evidence, which is at the exhibit that you had taken me to, which is 2A, tab 4, schedule 2. If we can look at page 4, and I'll just grab a year, if we can just look at 2020. So, you've got 12.4 million as the material handling on-cost. But in this response to B, it's 13.2 million. And I just wondered what the difference was between those two numbers?

MR. MUNDENCHIRA: The most significant portion of that difference should be the fact that table 1 in the Exhibit 2A reference is showing capitalized on cost, so it was charged to a capital project.

MS. GRICE: Okay, okay.

MR. MUNDENCHIRA: There may be some that went to operating expenses.

MS. GRICE: Understood, that explains it. Thank you very much. Okay. My next question relates to 2B-AMPCO-16. And you had a discussion about this issue with Mr. Garner this morning. So, in AMPCO -- and so I just have some follow-up questions, but in 2B-AMPCO-16, we asked for the calculation of 26 percent of assets at end of use of life by 2023. And you gave the formula, and my understanding is that you took the population of assets by asset class that were at or past useful life, and then you multiplied it by a representative unit cost for each of those assets and you arrived at 2.7 billion. Is that correct?

MR. HIGGINS: Yes, it is.

MS. GRICE: Okay. And where did you get your representative unit costs from?

MR. HIGGINS: They were developed a number of years ago now just for the purposes of this model. So, they would have been, you know, they would have been based on, essentially, a study of unit costs at the time. We tend to try to avoid updating them if only because then if you have too many moving variables in the model, it becomes a little less meaningful for what it is. So, it's a static unit cost set that we developed years ago.

MS. GRICE: Okay. And I don't think we need to turn this up, but in 2B-SEC-31 you had a table where you showed the percentage of each asset that was at or beyond useful life in 2023 at the end of 2023. And I wondered if you would be able to -- just there was a lot of discussion this morning about how that you came up with 25 percent. And I think it might be helpful to parties if you could take the number of assets in each asset class where you gave the percentage in 2B-SEC-31, and then show us the representative unit cost for each of those assets and multiply it out so that we can see how you arrived at 2.7 billion? And I think that then that would answer a lot of the questions that everybody seems to have.

MR. HIGGINS: So, essentially -- yes, I think that should be doable, yes, for one of the years.

MS. GRICE: Okay. Thank you.

MR. MURRAY: That will be undertaking JT1.10.

UNDERTAKING JT1.10: FOR THE ASSETS DESCRIBED IN 2B-

SEC-31, TO SHOW THE REPRESENTATIVE UNTI COST FOR EACH ASSET, TO SHOW THE DERIVATION OF THE 2.7 BILLION FIGURE.

MS. GRICE: Okay. 2B-AMPCO-18, please. Okay, these are just quick little questions. I just wanted to understand sort of the timeframe of when Toronto Hydro's implementing specific initiatives. So, I asked for the start date and end date for probability of failure, and you provided the end date, but I just -- if you could provide the start date, that would just be helpful.

MR. HIGGINS: You're referring to the first line of the response there?

MS. GRICE: Yes, "please provide the start date and forecast end date of the probability of failure" is the one I'm referring to, because you answered about the consequence of failure.

MR. HIGGINS: Sure, yes, we can provide that.

MS. GRICE: Okay. Thank you.

MR. MURRAY: That will be undertaking JT1.11.

UNDERTAKING JT1.11: REFERRING TO 2B-AMPCO-18, TO PROVIDE A START DATE FOR THE PROBABILITY OF FAILURE INITIATIVE.

MS. GRICE: Okay. And I have got the same type of question on 2B-AMPCO-20. And it has to do with the engineering asset investment planning initiative. You provided information around phase 3, but I wondered just the beginning of the initiative as a whole, when the start, if you could provide that?

MR. HIGGINS: Yes, we'll take an undertaking, I just want to make sure I get it correct, yes.

MR. MURRAY: That will be undertaking JT1.12.

UNDERTAKING JT1.12: REFERRING TO 2B-AMPCO-20, TO CONFIRM A START DATE FOR THE ENGINEERING ASSET INVESTMENT PLANNING INITIATIVE.

MS. GRICE: Okay. And then just one more, last one, 2B-AMPCO-21, just when you started the ISO 55000 certification. When did that initiative begin?

MR. HIGGINS: So the gap analysis initially was performed in 2020, and then we spent some time deciding whether or not to pursue the certification, and so it would have been in 2021, I don't know if I can pinpoint the month off the top of my head, but in 2021 is when we started.

MS. GRICE: Okay. No, that's fine, that's great. Thank you. Okay. Now, if we could just go to AMPCO-62, please. Sorry, I'm just getting there myself in my paper version. Okay.

You provide a number of major asset failures by asset type, and I just wanted to understand, when you provide, say, in table 1, are all of these failures do they result in an interruption? Is that what's included in table 1?

MS. NARISETTY: It could be a combination of an asset that was replaced after it failed, and hence caused an outage, or may fail imminently, or in a short period of time, and hence the asset was replaced.

MS. GRICE: Okay. Okay, thank you. And then in table 2 on page 2, where you show number of interruptions by

major asset category, so then those are a subset. They're the result of an asset that actually failed and caused an interruption?

MS. NARISETTY: Subject to check, yes.

MS. GRICE: Okay. Thank you. Can we please go to AMPCO-42. And I wanted to look at the appendix that was filed with that response, which is Appendix A. So, what this shows is the forecast number of units that were being installed in all of your programs 2020 to 2024, and compares it against what you actually did, including the forecast for 2024, and I wonder, do you have this information available on a global basis like this for 2025 to 2029 for all of your programs that are in your DSP?

MR. HIGGINS: I would have to check whether or not it already exists in this format, but likely it could be assembled in this format, yes.

MS. GRICE: Okay. Thank you, that would be great, thank you.

MR. HIGGINS: Okay.

MR. MURRAY: That will be undertaking JT1.13.

UNDERTAKING JT1.13: REFERRING TO AMPCO-42, APPENDIX A, FORECAST UNITS INSTALLED, TO PROVIDE DATA FOR 2025-2029 FOR ALL PROGRAMS IN THE DSP.

MS. GRICE: Okay. And then I just have a question from 4-AMPCO-91, part C. And I just wanted to understand the way that Toronto Hydro plans its vegetation management cycles. I've just seen with some utilities they geographically divide the service area into, say,

quadrants, and then you have a four-year cycle? I don't think that that's the way Toronto Hydro does it.

Can you just help me out and explain how you plan your vegetation management cycle? And if you have -- if it's classified as something like a three-year cycle, four-year cycle?

MS. NARISETTY: I can take you to our response to IR 4-Staff-289A. So here, we outline our strategy and how we schedule vegetation management, which is done on an annual basis where we prioritize the feeders on an annual basis with a multi-year view, while taking into account factors such as the historical reliability of the feeders, the number of customers by each feeder, and the time elapsed since the last pruning.

MS. GRICE: Okay. So you don't do it on a fixed schedule. You develop it on an annual basis?

MS. NARISETTY: Yes.

MS. GRICE: Okay. Okay. That's great. Thank you.

And I just have one more question: 2B-AMPCO-75. Okay, I had a question just about the number of deficiencies. And I just wanted to -- sorry, can we look at table 1 in response A, please? So I just looked at the -- I added up the number of deficiencies, P1 to P3, and I get 11,707.

And then I just want to reconcile that against a table in the evidence where you talk about various things that are going on with your system. So that's at 2B-D2-table 1, page 17. Here we go. Okay.

So if you look under priority deficiencies for this -- table says that all figures are 2022 year-end actuals. So it says here that there were 12,589 deficiencies, and then that table that I took you to in the IR response totals 11,707.

So I just wondered what the difference between those two numbers would be?

MS. NARISETTY: So you are comparing the 2022 numbers?

MS. GRICE: Yes.

MS. NARISETTY: We can undertake to provide that answer.

MS. GRICE: Okay. Okay, thank you, very much.

MR. MURRAY: There will be Undertaking JT1.14.

UNDERTAKING JT1.14: TO EXPLAIN THE DIFFERENCE FOR 2022 YEAR END FIGURES FOR PRIORITY DEFICIENCIES.

MS. GRICE: Okay. I am finished, now. Thank you, very much, panel.

MR. MURRAY: Thank you, Ms. Grice.

Before we go to the next person, I just wanted to -- because we had a discussion off the record here in terms of the schedule, I wanted to let the parties that are participating remotely to know that we are no longer planning two breaks for this afternoon. Rather, we are going to plan to have one break shortly after three o'clock for a slightly longer period, so maybe a 20-minute break around 3:05 or so. That is what we are sort of aiming for towards, right now. I just wanted to make sure everyone was aware of that.

And with that, I will pass things over to Mr. Daube of DRC.

EXAMINATION BY MR. DAUBE:

MR. DAUBE: Hi, everyone. How are you, today? I am Nick Daube, I represent DRC.

I would like to start, please, at 1B-DRC-2. Under question C, under "Environmental and Social", you say:

> "A growing awareness of climate change, peer influence and community norms can drive more customers to choose DERs."

Then under "Government Incentives and Business Models", you use the example that can new business models can provide new options and incentives for adopting DERs.

So, with those general concepts in mind, I want to ask you a few questions about variables that drive demand with a relatively new technology or set of technologies.

So I take it in these questions and elsewhere, you are generally accepting that social norms, things like awareness levels and access to options all influence the rate of adoption with a technology, just as a general point?

MR. HUNTLEY: The answer is yes.

MR. DAUBE: And would you agree that these types of variables are more influential in the case of DERs, than they are with more established technologies or options?

MR. HUNTLEY: One moment, please. Mr. Daube, can you rephrase the question?

MR. DAUBE: Yeah. I am just looking to see, just

testing the idea that there's more movement, maybe is the better way to put it, with new technologies when it comes to factors like awareness levels, like social norms, the ones that we just went through, there's more movement on those generally speaking in the case of newer technologies than established technologies?

MR. HUNTLEY: Toronto Hydro will acknowledge that awareness does play a specific role in terms of influencing the adoption of DERs.

MR. DAUBE: Okay. That wasn't really the question, but I appreciate the answer. Maybe I can just move on, because I don't think it's an important point.

Is it fair to say that awareness levels, social norms, access to options, those things aren't uniform across your service territory? That, in fact, they are going to play out in different ways across your service territory?

MR. HUNTLEY: The rates of adoption of DERs will vary across the Toronto Hydro service territory. That is acknowledged.

MR. DAUBE: Okay, maybe I should get more precise. You will agree that in one neighbourhood the awareness levels of the attractiveness or access to DERs isn't going to be necessarily identical to those same things in the next neighbourhood?

Or are you saying that they are going to be exactly the same, neighbourhood to neighbourhood, across your service territory?

MR. HUNTLEY: There are numerous factors that affect

the adoption of DERs from one neighbourhood to the next, awareness being one variable amongst a range of others.

MR. DAUBE: Okay, and what about the answer to my question?

MR. HUNTLEY: Could you please repeat?

MR. DAUBE: I want to know whether you're saying that awareness of the attractiveness or lack thereof, awareness of access to options when it comes to DERs, whether your position is that it is going to be identical neighbourhood to neighbourhood, those awareness levels, or whether there will be variations in that level of awareness across your service territory.

MR. HUNTLEY: Toronto Hydro has not studied that aspect of DER adoption specifically, but I think it can be stated that there would be an expectation for some variation between neighbourhoods, with respect to adoption.

MR. DAUBE: And you've acknowledged in your evidence, I believe, that social norms, awareness levels, and access to options all influence the rate of adoptions. Do you also agree that existing levels of those three things aren't predictive of where they're going to be five years from now?

MR. HUNTLEY: The utility recognizes that consumer behaviour, influenced by some of the factors you earlier described, does have a profound impact on adoption rates, and we recognize that in the plan that we have put forward when it comes to a recognition of variability and flexibility on the electrification journey. So, with

respect to variability of adoption rates, I think the utility has appropriately recognized that fact in the plans that we've presented before the board.

MR. DAUBE: Can you go to 2B-DRC-7, please, question A and response A, please. If I understand correctly, you're saying here that your DER forecast relies on your historical DER connection trends, project pipeline, economic environment, and energy policies at the time of the forecast. Is that correct?

MR. HUNTLEY: Yes, that's correct.

MR. DAUBE: Is there anything else that your DER forecast relies on?

Is there anything missing from your answer here?

MR. HUNTLEY: No.

MR. DAUBE: Is there anything here that you say is forward looking as opposed to looking at historical trends or historical facts?

MR. HUNTLEY: Mr. Daube, the forecast that has been prepared as part of this plan, first of all, is updated annually, so it is responsive to evolving conditions due to some of the factors that you described. In the near term, our forecasts are influenced by pipeline projects, projects that have commitments associated with them, and therefore reflect, in our view, what would amount to a stable forecast period.

In addition to that, I do think that it is important to note -- and we allude to this in several parts of the evidence, itself, with respect to the DER forecast -- that

it is responsive to policies, as well. So, with that combination, it gives us confidence that it is responsive and reflective of future conditions, with the flexibility to adjust as the plan evolves.

MR. DAUBE: Is there anything else, aside from what you've just stated, that goes into your DER forecast that incorporates the possibility of future changes to existing trends?

MR. HUNTLEY: We do evaluate our forecasts and the variables on an annual basis.

MR. DAUBE: With respect, I'm just going to be pressed for time if you repeat your answers. So my question was whether there's anything else aside from the evidence you just gave.

MR. KEIZER: Sorry, with all due respect, Mr. Daube, it's not cross-examination, it's a technical conference, so, if the witness has an answer, he's going to give the answer.

MR. HUNTLEY: Could you repeat the question, please?

MR. DAUBE: Is there anything in addition to the evidence you've just given that factors into Toronto Hydro's DER forecast in a way that incorporates the possibility of future changes to existing trends -- I believe that was the question, and I would say -- or anything else that you mention here that goes into your forecast in the response to A?

MR. HUNTLEY: We evaluate on an annual basis, and we will adjust as additional variables are deemed necessary.

MR. DAUBE: Is there anything in your answer to A here that accounts for the possibility of changing social norms when it comes to DERs, aside from the annual updates that you've mentioned?

MR. HUNTLEY: Mr. Daube, our answer to part A stands. We have incorporated the variables at this time we deem appropriate. Should it need adjustment on an annual basis, we're prepared to do so.

MR. DAUBE: Same answer for both changing awareness levels and changing access to options when it comes to access to DERs. Is that correct?

MR. HUNTLEY: That's correct.

MR. DAUBE: Thank you. Can we go to question B, please, second paragraph, I think this is just a clarification. You say Toronto Hydro accepts that support of DER and EV programs is integral to customer adoption of these technologies.

Do you mean to say that Toronto Hydro accepts that its support of DER and EV programs or is that meant to be a general statement? I appreciate you had about 10,000 answers to write here.

MR. HUNTLEY: With respect to the application, the context is Toronto Hydro support.

MR. DAUBE: Okay. Is part of the reason why Toronto Hydro support is integral is because that support is a central part of ensuring that that adequate infrastructure is available to meet any increases in DER demand?

MR. HUNTLEY: That would be an accurate

characterization, yes.

MR. DAUBE: Is another part of the reason because Toronto Hydro support is integral to producing increased customer awareness of options when it comes to DERs?

MR. HUNTLEY: Can you clarify the question, Mr. Daube?

MR. DAUBE: I'm just trying to flesh out why your position, which I'm not taking issue with, but why your position is that Toronto Hydro's support is integral to customer adoption?

So, I would assume, and you've confirmed access -- ensuring adequate access to infrastructure is part of why you say integral. I would also assume that you have an integral role to play in increasing customer awareness of options, so I'm looking for you to confirm that.

MR. HUNTLEY: With respect to the awareness, those activities are part of our non-rate-regulated business, but the company has taken steps to ensure that the benefits of DER adoption are communicated to customers.

MR. DAUBE: Okay. Well, aside from ensuring access to infrastructure, is there any other reason why Toronto Hydro takes the position that its support of DER and EV programs is integral to customer adoption of these technologies, or is it just ensuring access to infrastructure?

MR. HUNTLEY: As far as the capital plan is concerned, and the one before the Board, access to infrastructure is critical -- a critical element of what we are putting forward.

MR. DAUBE: Okay. The question is when you say your

support is integral, you've clarified that Toronto Hydro accepts that its support of DER and EV programs is integral. We've talked about how access to infrastructure plays in. Are there any other headings that I'm missing? And I'm not pushing you on one way or the other, the answer might be, no, that's it.

MR. HUNTLEY: As far as distributed energy resources are concerned, the utility has explored and continues to explore opportunities to leverage DERs for non-ORs solutions.

MR. DAUBE: Okay. I'll take that as a no, unless you want to correct me. I think it's a yes or no question.

MR. KEIZER: I just will also point out. I'm not sure the direction of your question, Mr. Daube, whether or not there may be participants on panel 2 that can speak to some of the customer support aspects that may go towards this as opposed to just purely on the capital side. So...

MR. DAUBE: Okay. That's a good point.

MR. KEIZER: I don't want to take it as though that this is the -- there may be opportunity for you to explore it there.

MR. DAUBE: Okay. Great. And listen, this isn't a crucial point. If there are any headings that Toronto Hydro wants to add later on, I'm happy to take it. But I appreciate the clarification on both the customer support and infrastructure.

Can we go to 1B-DRC-2, question D and E, please. In the second paragraph of your response, you acknowledge here

that the highest level of DER uptake in the FES report would include more constrained feeders, issues with existing protection systems, and voltage regulation issues.

My question is: Is it correct to assume that these constraints will be faced on a localized basis or is it the case that if DER implementation outstrips your ability to handle it, it's immediately a levelized problem across your network?

MR. HUNTLEY: Mr. Daube, it will occur on a localized basis.

MR. DAUBE: Is it fair, then, for me to assume that neighbourhood characteristics, or localized characteristics are a very important variable towards determining where constraints may exist?

MR. HUNTLEY: Can you clarify what you mean by localized neighbourhood characteristics?

MR. DAUBE: Yes, well, I guess what I'm confirming here, I think this is an obvious point, but in order to understand and anticipate whether constraints on -- constraints are going to exist, you not only have to know what infrastructure is in place in order to meet demand, it's very helpful to know what the likely demand characteristics of a neighbourhood or the applicable localized zone are. Is that clear enough?

MR. HUNTLEY: Yes. That would be part of the analysis.

MR. DAUBE: Okay. And among other things, those more localized characteristics are important towards determining

what constitutes sufficient investment to adequately meet demand in those areas, is that right?

MR. HUNTLEY: Can you please repeat that question?

MR. DAUBE: So, among other things, understanding more localized characteristics that can inform your understanding of what demand in the area is likely to be, understanding those characteristics is important towards understanding what sufficient investment to meet demand is going to be?

MR. HUNTLEY: If your question is attempting to determine if we match the level of investment to satisfy a particular localized need, the answer is yes.

MR. DAUBE: Thank you. That's a much clearer way of putting my question, so thank you.

Can we go to 2B-DRC-10, please, and question C. Off the top here, you say DER connection location probability greatly varies and is determined by customer demand. I'm just -- and this is no criticism, again, I know you had 10,000 answers to write here.

Are you saying here that -- is this just saying that demand is going to vary across your service territory on a localized basis, some areas more demand, some less?

MR. HUNTLEY: The response in part C is meant to indicate that there is variability, and the complexity and the ability to forecast, specifically where demand will materialize for DERs. And there is variation across the service territory.

MR. DAUBE: Why? Why is that?

MR. HUNTLEY: Because the ability or the choice to adopt DERs, amongst other things, is influenced by consumer choice. And there is significant variability in how that materializes in the system. That is why it is challenging to forecast specifically where DERs will materialize.

MR. DAUBE: Can we go to 1B-DRC-2, please, and questions D and E? - or, rather, your responses, I guess.

There is a paragraph that begins, "One benefit of a scenario-based". It's on -- yes, there it is, thank you. So you write here:

> "One benefit of a scenario-based model such as FES is that the utility can track developments as they occur and determine which scenario is most closely being followed and plan the necessary investments accordingly, to ensure that the utility is able to meet demand."

Your answer to this may be the annual update. I am just trying to understand what processes do you have in place to do this, to do what you describe in this paragraph? And I am hoping for a little bit of elaboration, if it's just the annual update.

MR. HUNTLEY: I'm sorry, Mr. Daube, which paragraph are you referring to specifically?

MR. DAUBE: Yes. Right in the middle of the screen there, it says:

> "One benefit of a scenario-based model such as FES is that the utility can track developments as they occur and determine which scenarios is most

closely being followed and plan the necessary investments accordingly..."

So I guess, maybe to be a bit more precise, what processes do you have in place to track developments as they occur and determine which scenario is more closely being followed? That would be the first subquestion.

And the second subquestion is what processes do you have in place to plan the necessary investments accordingly, to ensure that the utility is able to meet demand?

MR. HUNTLEY: Thank you for the question, Mr. Daube. I will answer the first part initially by stating two things.

First of all, in addition to our annual forecasting update process, we do conduct an annual investment plan and portfolio reporting process. Between those two processes, we update our capital plans on an annual basis to reflect evolving conditions.

Specific to DERs, DERs are tracked by connection and trended as such. And this gives us a relatively granular view of rates of connection. And it is from that process we are able to judge emerging constraints and take appropriate action to mitigate, should they be necessary.

MR. DAUBE: Does that answer apply in the case of DERs as well? It's the same process, or a part of the same process?

MR. HUNTLEY: Yes, that's correct.

MR. DAUBE: In the next paragraph, the very -- I guess

the last two sentences, you say, if the rate of DER uptake significantly outpaces that reflected in your forecast, it will likely be necessary to increase the scope of investment in solutions.

And it goes on.

So my question is, when you are monitoring in the future for that possibility of DER uptake significantly outpacing your existing forecast, will your monitoring include more localized analysis and review as opposed to what is happening across your system in its entirety?

MR. HUNTLEY: That's correct, Mr. Daube. Our analysis always commences with a localized review.

MR. DAUBE: Why is that?

MR. HUNTLEY: Because the investment needs to be matched to a specific need, which manifests itself on a localized level first, before it has larger system implications.

MR. DAUBE: Is your monitoring and review process entirely responsive to demand as you see it developing? Or is there also an aspect to it that is looking to recognize opportunities to accelerate things like DER uptake, the adoption of electric vehicles and to help assist that growth?

MR. HUNTLEY: Mr. Daube, in exhibit 2B, section D5, the utility outlines several initiatives that it intends to undertake as part of the grid modernization strategy.

Now, integral to those plans are initiatives that will investigate the enhanced use of leveraging DERs for grid

benefit, in addition to -- and this is also outlined in our non-wire solutions, exhibit 2B, section E, 7.2, our use of battery energy storage as part of our enabling investments to encourage and facilitate additional DER connections where restrictions may exist with respect to minimum load-to-generation ratios on specific feeders.

MR. DAUBE: So I think, recognizing that and recognizing those very positive efforts, what I am trying to test here is whether efforts to recognize opportunities to support DER adoption essentially crystallize and freeze at the beginning of this plan, whereby it becomes very difficult to, you know, move the ball forward until five years from now.

Or whether there is something that you are referencing in this annual process that continues to allow you not only to respond to evolving demand but also to make similar efforts to the ones you just took us through, to continue to support the acceleration and transition. Is that clear enough?

MR. HUNTLEY: Yes, Mr. Daube. It is. The utility has put forward a plan that demonstrates the need for flexibility as we approach or continue along the journey considering electrification. We have outlined and proposed a demand-related variance account that is meant to recognize the risk associated with demand-related investments and appropriately protect the ratepayer and utility from the impacts and the risks associated with that level of variability.

MR. DAUBE: Okay, thank you. Can we go to 1B-DRC-3, please, and specifically question and answer to B, the second paragraph of the response. So Toronto Hydro here states:

> "Hypothetically, if a much higher electrification scenario occurs and Toronto Hydro fails to make necessary investments in a timely manner, this would have negative impacts on the various topics listed in DRC's question."

I recognize this is not the approach Toronto Hydro has recommended or has adopted. What I'm generally trying to understand is whether an approach that totally mitigated the risk of infrastructure investments not keeping up with DER and EV demand, whether that just means more money or if it means other disadvantages.

So my question for you is: Could you please sketch out what Toronto Hydro's approach would be if it were looking to mitigate the risk of failing to keep up with higher electrification or DER scenarios? And, you know, I don't need, you know, the most detailed answer in the world. I'm really just looking for the pillars here, to understand whether it would just mean more money and more investments in infrastructure that supports DER and electric uptake.

MR. HUNTLEY: Mr. Daube, Toronto Hydro has proposed a plan utilizing a least-regrets philosophy. And that basically means, in a nutshell, we're advancing investments that represent, in our view, the minimum to achieve long-

term value for the ratepayer without the possibility or the risk of stranding assets in the future.

Accompanying that proposal is the demand-related variance account, to which we will ascribe changes above or below the plan to accommodate a scenario like you've described, whereby there is an accelerated pace of DER proliferation due to additional demand for that particular type of technology.

MR. DAUBE: Yes, well, okay. Well, let me ask this another way. If you knew that the highest electrification scenarios were going to play out, presumably you would be suggesting today two questions here. Presumably, you would be suggesting here today higher levels of investment to support that higher demand; and, number two, failure to make those investments today doesn't necessarily mean you can't make them later on, but my guess is it's going to be more expensive if you're required to make those investments on a more expedited timeline, in all likelihood. What do you say to those two questions?

MR. HIGGINS: Maybe I'll just chime in here. So I think, just to expand on my colleague Mr. Huntley's response, the least-regrets approach that we took to developing the plans, including the grid modernization strategy associated with DERs in this rate application, kind of cuts both ways. It is a balancing act. And so, while we certainly don't want to put off investments that we have a reasonable degree of confidence are going to be needed and therefore, to your point, they become more

expensive, because we delayed or perhaps even not possible because we delayed. We also don't want to invest too early because that also creates negative value for ratepayers and the company.

So it is a balancing act. So, you know, in the hypothetical situation, where demand is much higher, we would be proposing a plan that is higher. But that is not the forecast that we have in front of us.

MR. DAUBE: Is there any disadvantage, aside from cost, to making those additional investments?

And I take the point about stranded assets. I mean, I think that feeds into costs generally speaking, the costs of carrying those assets, but you might put those in a different category. So maybe the better way of asking this is: Are there any disadvantages to those higher level of investments, aside from costs and the risk of stranded and underutilized investments -- assets? I'm sorry.

MR. HIGGINS: Certainly with respect to the topic of DERs, I think, because the technology required, especially on longer time horizons, to accommodate more DERs is more innovative in nature, there is the risk of technological obsolescence, as well. So, if we go down a particular path and commit to a particular technology stack in order to support large amounts of DERs and they don't materialize, because we are talking about operational and digital technology, we could find ourselves having to replace and upgrade that without having gotten any of the value out of it. So There is that side of it, as well.

MR. DAUBE: Right. Okay. That's helpful. Anything else?

MR. HIGGINS: Those are the things that come to mind at this time.

MR. DAUBE: Thank you. That's helpful. Can we go to the next page. When we look at your responses to what the implications in the midterm of underinvestment are -- this is my characterization, but I think it's fair to say there's a tonal shift from what you describe in the midterm versus the short term, including language like, under "customers", "customers could face significant power quality issues", under "investments and DERs", you talk about finding yourself "turning away large volumes of prospective DER projects."

Just in a general sense, when you think about this internally, is there an inflection point where this goes from, you know, the smaller kinds of problems that we see in the rebasing period to the much larger problems in the midterm in the underinvestment scenario?

Like, is there a general time frame when you're saying internally: If we don't get our house in order on these matters, this becomes a much more significant problem?

MR. HIGGINS: Mr. Daube, I mean, it's hard to sort of pinpoint an exact timeframe because these are sort of hypothetical kind of directional scenarios. However, you know, based on some of the research that we did within the future energy scenarios report for example, you know, I think like many other utilities have been saying who have

done similar studies, we would expect the inflection point in the adoption of these and various other technologies associated with electrification to begin to accelerate sort of beyond this next rate period.

So, while we may start to see some issues, and we, in fact, you know, already have some parts of our system that have some restrictions for accommodating DERs. We wouldn't expect to start to see these more series issue materialize, these more widespread issues until sometime in the 2030s. Now, exactly when depends on how things evolve, and our view on that, you know, gets updated over time, you know, basically on a monthly basis, just based on what's happening in the sector. So...

MR. DAUBE: Thank you. If we go to response C, I'm conscious of my time here. I think I'm rounding the corner here, so if it's all right to keep going?

MR. MURRAY: Mr. Daube, it's Mr. Murray here, just want to get a sense. I think you're already to your time, we have a little bit of flexibility, we're a little bit ahead of schedule but I'm also mindful of the fact that some of the questions that some of the parties seem to think were for panel 1 may be for panel 2. So, I'm hoping we're at least on schedule, if not a little ahead going into panel 2, because the times there might be a little bit longer than anticipated. So, perhaps if you can try to wrap it up in the next 5, maybe 10 minutes?

MR. DAUBE: That's exactly what I was going to say, so thank you. And I'm in your hands. If I see you flailing

your arm understands on the screen, then I will know to wrap it up. Thank you.

Response C, I think I'm just looking for an elaboration here, and the last couple of answers, if you just want to refer to them, this may be a complete answer.

When you talk about under-utilized or stranded assets and technical -- I'm sorry, technological obsolescence. I think you've already given me a full picture of what you mean by technological obsolescence. Have you given me a complete answer on what you mean by under-utilized and stranded assets in the case of DERs. What do you mean by that?

MR. HUNTLEY: Thank you for the question, Mr. Daube. I'll generally take you to exhibit 2B section E5.5, where we discuss at length our capital investments to enable the connection of DERs. And critical, critical to those investments are investments around bus tie reactors that would be used in our stations to mitigate and reduce the impact of high fault levels due to the connection of DERs.

MR. DAUBE: Okay. So --

MR. HUNTLEY: Those would be one category of investments that we would refer to as stranded in this context.

MR. DAUBE: Any others or is that the main one or the only one?

MR. HUNTLEY: In our stations expansion evidence, in exhibit 2B, section E7.4, we allude to the expansion of Sheppard to Yes, which is driven by the need to alleviate

short circuit constraints in that area of the city. That would also be categorized as a stranded investment in this context.

MR. DAUBE: Okay. Anything else you want to add or that's it?

MR. HUNTLEY: Not at this time.

MR. DAUBE: Thank you. Can we go to 1B-DRC-5, please, question C. Just some brief questions about EVs. So, question C, just looking for the elaboration here. Whether the general indicators that will determine for you when EV energy storage systems can be aggregated to provide meaningful capacity?

MS. MARZOUGHI: Thanks for your question. So, I think as some of my colleagues today have outlined several times, just with respect to our general planning process, it's come up a few times that it is a grounded in a ground-up analysis of the system that's driven by needs. And then, that's how we make our investment decisions. And in terms of our use of non-wires, it's no different.

So, we look at our system needs and we assess on a localized basis what the application of demand response in this case would be, and how it can provide system value. And the reason for that is because we always have to ensure that we have a good framing and understand of what the conventional solution would be that we're displacing, using demand response. And in this case you're talking about EV, EV demand response.

And so, it's not that we would not utilize EV demand

response. We're very open to it. However, just understanding that it is a very, very small amount of capacity, so it must be aggregated in order to provide that kind of system, localized system, benefit that I was talking about earlier.

So, it becomes meaningful when it can be aggregated to provide that kind of localized system capacity. And so, even at this time as we pursue our procurements of non-wires, we're very open to this, and to -- if there are parties who are able to aggregate EVs in this manner, it would not be something that we would not be, you know, interested in pursuing, we would be open to that. However, that's not been the case thus far.

MR. DAUBE: And on that last point, do you have any insight on where we stand today versus where we'd need to get for, in your judgment, it to be possible for devices to be aggregated to provide meaningful capacity -- sorry, that's an awful way of asking the question.

Where are we today compared to where we need to be in order for the conditions in this first sentence to be satisfied, and do you have insight on that?

MS. MARZOUGHI: I don't have -- I'm not an expert on where we are in terms of, you know, in the City of Toronto in term of all the EV uptake and the ability of EVs to provide this type of service, but I think it's a matter of numbers. And as EV uptake grows, and continues to grow in the city, and as different third parties become more equipped to be able to leverage that capacity, that is -- I

think that it can only improve, and we are doing -- I think we do outline in our evidence in 2B section D5 2.2.2.5, talk about our plug-in drive pilot, which is a pilot that we have been running during this rate period that works with a company called Velocity, and we're looking at the ability to track and manage EVs and conduct demand response in this way. But It really is a matter of just more of these programs popping up, and more EVs popping up and Toronto Hydro would be very willing to utilize that capacity as long as it can be aggregated in areas where we have actual system need.

MR. DAUBE: Great. Thank you. Two quick ones, and then I'm done. 2B-DRC-7, please. And response I, you reference a 2019 report -- do I not have it right? 2B -- no, I do have it right. You reference the report from Pollution Probe. I'm unclear whether you're adopting its conclusions, and specifically the 14 -- whether you agree with the 14 barriers that Pollution Probe identified.

If I am catching you on the spot, especially recognizing the volume of materials, I am happy to take this way by of an undertaking whether you agree with the 14 barriers and, if not, which ones and why not?

MR. HUNTLEY: Mr. Daube, with respect to the response to this IR, this reference was just -- this particular document was offered as reference. It did not constitute Toronto Hydro's adoption of the report itself.

MR. DAUBE: Okay. Can you let me know by way of undertaking which of the 14 barriers you agree with? And

if you don't agree with some of them, why you don't agree with some of them?

MR. KEIZER: That's fine. We'll take the undertaking.

MR. DAUBE: Thank you.

MR. MURRAY: That will be undertaking JT1.15.

UNDERTAKING JT1.15: TO CONFIRM WHICH OF THE 14 BARRIERS THESL AGREES WITH.

MR. DAUBE: I think this one is just an oversight: 2B-DRC-10, questions A and B. My client asked you -- if you scroll up a little bit, please? Please elaborate on customer interest related to solar power since the last rebasing period.

And I don't think I got an answer to it. So if you want to point me to the aspect of your answer that -- or the existing answer that is responsive to that question, I am happy to be referred now. But otherwise, I would just ask you to answer the question now: Can you tell me a little bit about how customer interest related to solar power since the last rebasing period has developed? And you can refer to the preamble above.

This question was grounded in your original statement that it has grown in recent years; DER connections, I guess, was the reference.

That's a very long question. Really, I want to know what your perspective is in a higher level sense on how customer interest related to solar power has developed.

MR. HUNTLEY: Thank you, Mr. Daube. The statement or the response to that question is meant to communicate that

we have observed continued and growing interest in DER connections, specifically in using solar technology.

The basis for that is our connections -- our assessments, our applications, as well as the connections pipeline that we are managing. It has been steadily increasing since 2020, and continues to do so.

MR. DAUBE: Okay. That is very helpful. Thank you, very Much. And thank you for everyone's patience.

MR. MURRAY: Thank you, Mr. Daube. Ms. Girvan.

EXAMINATION BY MS. GIRVAN:

MS. GIRVAN: Good afternoon, panel. Can you hear me? Okay. Thanks. My name is Julie Girvan, and I represent the Consumers Council of Canada. So I am going to be mostly referring to the interrogatories that we posed.

If you could turn first to 1A-CCC-6.

So I am just curious as to this change in the basic connection charge, and I wondered what the rationale was. And you referred me to section 2B -- sorry. Where does it say -- oh, Exhibit 8, tab 2, schedule 1. And I didn't see reference to this, there.

So I would just like to understand a better understanding of this charge, and explain why the change has taken place. And we can start with that.

MS. NARISETTY: If I can take you to Exhibit 2B, section E5.1, page 20. So, yes, right here at the bottom, starting at lines 21, we talk about the change, and why we're making it and what we are changing.

And to summarize, we are proposing to increase the

basic connection fee allowance from $1,396 to $3,059. And this is something that has not been updated since 2009. And the updated fee reflects the current cost of making this basic connection.

MS. GIRVAN: So what is the basic connection? Can you help me understand that?

MS. NARISETTY: So the basic connection is defined under the Distribution System Code. And it allows the utility to recover the cost of the basic connection as part of our revenue requirement. And, at a minimum, it includes the supply and installation of a transformation, and anything else that goes with it to make that basic connection.

MS. GIRVAN: So it is just connecting from your system to someone's home. Is that it?

MS. NARISETTY: At a basic level, a simplistic level, yes.

MS. GIRVAN: Okay. And so is this now -- you are saying this is cost based?

MS. NARISETTY: Yes.

MS. GIRVAN: So you have done calculations to demonstrate that that's the actual cost of that connection?

MS. NARISETTY: Yes. It reflects our current costs.

MS. GIRVAN: Do you have more details on that?

MS. NARISETTY: I mean, not off the top of my head, but we have gone into details to come up with $3,059.

MS. GIRVAN: Could you undertake to provide that, please?

MS. NARISETTY: Yes.

MS. GIRVAN: Thank you.

MR. MURRAY: That will be Undertaking JT1.16.

UNDERTAKING JT1.16: TO PROVIDE THE CALCULATIONS BEHIND THE INCREASE IN THE BASIC CONNECTION FEE TO $3,059, SHOWN AT EXHIBIT 2B, SECTION E5.1, PAGE 20.

MS. GIRVAN: And I just wanted to go back to the Interrogatory. I think we asked you about customer communication about this, and it's not clear to me that you either consulted your customers about this, or how you are going to inform them that this is actually an increase in the charge?

MS. NARISETTY: Yes. So going back to our response to 1A-CCC-06, we didn't directly ask them on this particular subject. However, customers did indicate to us that, you know, reliable and affordable service is a priority for them. So this increase to the basic connection allowance is consistent with it.

And, once this change is approved by the OEB as part of our regular process to communicate with the customers for any changes to the conditions of service, at that point it will be specifically put in front of them.

MS. GIRVAN: In what way?

MS. NARISETTY: As part of our communication when we implement this change through the conditions of service.

MS. GIRVAN: Okay. So you are actually asking the OEB to specifically approve this charge?

MS. NARISETTY: Yes.

MS. GIRVAN: Okay. Is that typical, with your service charges?

MS. NARISETTY: In this particular case, yes.

MS. GIRVAN: Okay. Okay, thank you.

If you could turn now to Exhibit 1B-CCC-9. And Toronto Hydro referred to a number of initiatives being undertaken by the City of Toronto, and I didn't really get a response about how the Toronto green standard has impacted your rate plan. And I just wondered if you could help me with that.

MS. NARISETTY: Can you please repeat the question?

MS. GIRVAN: Sure. Can you explain how the Toronto green standard has impacted your rate plan, if in any way?

MS. NARISETTY: Not in a direct manner.

MS. GIRVAN: No? So you didn't make any changes related to that green plan?

MS. NARISETTY: Not in any direct manner.

MS. GIRVAN: Okay. Also, with respect to the Toronto EV strategy which was referred to, as well, I just wondered. It says that you have incorporated this, but I haven't seen sort of in terms of magnitude, in terms of whether it impacts your load, your revenue, your costs, anything like that.

MR. HUNTLEY: Thank you for the question, Ms. Girvan. With respect to the City of Toronto's EV strategy, it does have an impact with respect to our peak-demand forecast. The vehicle populations that were in that particular strategy did serve as an input into our peak-demand

forecast.

MS. GIRVAN: Do you have any sense of magnitude?

MR. HUNTLEY: Could you clarify what you mean by "magnitude"? Are we talking about costs, load?

MS. GIRVAN: Just any of that, yes.

MR. HUNTLEY: I do not have that number with me. I do not think we disaggregated the cost element attributable to any specific driver in the peak-demand forecast. It was an aggregated view that drove the plan, so we would not be able to disaggregate the cost of electric vehicles with respect to the capital plan.

MS. GIRVAN: Okay. Thank you. Now, could you please turn to Exhibit 1B-CCC-10? So Mr. Garner, I think, first off this morning was asking about this idea of asset population operating beyond it's useful life. And I think you said, in the 2018 to 2024 period, you had budgeted $1.8 billion to deal with this issue in terms of system renewal, and, at the end of 2023, 25 percent of your asset population is operating past its useful life. Is that correct?

MR. HIGGINS: Ah, 25 percent by the end of 2023. Sorry, I wasn't sure if I heard you correctly.

MS. GIRVAN: Yes, sorry, 25 percent. Yes. And then you had proposed $1.8 billion in the last case with respect to system renewal and metering. What did you actually spend in that period, on that specific item?

MR. HIGGINS: We're just going to do some quick math here, so just one second.

MS. GIRVAN: All right.

MR. HIGGINS: So, if you tally up actuals on metering and renewal, it's approximately $1.5 billion.

MS. GIRVAN: Okay, so you spent less than what was approved for that item. The 1.8, I think, is referred to. $1.8 billion was proposed for system renewal and metering. It's on the screen.

MR. HIGGINS: Yes, that's right, and we have described those variances in various other place in the evidence.

MS. GIRVAN: Okay. So the other thing is that, in 2025 to 2029, you're proposing on the same item, system renewal and metering, to spend $2.2 billion. Is that correct?

MR. HIGGINS: That's correct.

MS. GIRVAN: Okay. And that will take you to 27 percent of your assets past useful life by the end of -- I guess it's by 2030, so over the rate plan.

MR. HIGGINS: Sorry, Ms. Girvan. Can you say that again?

MS. GIRVAN: 27 percent. It's right at the top of the page.

MR. HIGGINS: So, no, sorry, that -- just to clarify, that 27 percent is not referring to -- I can see the confusion. It's not referring to the assets past useful life measure. That's a 27 percent increase in the system renewal and metering spending versus what was proposed, I believe, in the previous rate application.

MS. GIRVAN: Okay, so where do you plan on ending up

at the end of the -- I guess by 2030, in terms of asset population operating past its useful life?

MR. HIGGINS: Yes. So, per the discussion with Mr. Garner earlier this morning, we don't have a -- we don't set a precise target, and we don't have a model that gives us a precise outlook on that. It's not something -- basically, we don't set targets on the basis of age, so we would need to know specifically the assets we're replacing overall, essentially, when we filed this rate application. It would have been seven years looking out, which we don't have. So, you know, our goal is generally to keep these kinds of large, slower moving statistics as stable as we can, but there's no particular objective.

MS. GIRVAN: So is your goal typically, though, around 25 percent? Is that what you sort of live with?

MR. HIGGINS: More recently, that has been where we've been at. I think, if we were to rewind the clock to our first CIR application, we were closer to 30 percent in that pie. I would have to go back and check at this point. So it's through investment that that has come down, and, at this stage, we're looking to maintain more than anything.

MS. GIRVAN: Okay. Did you give Mr. Garner an undertaking about where you think you'll be? I can't remember.

MR. HIGGINS: No.

MS. GIRVAN: Oh, okay. But you're asking the Board in this category to spend $2.2 billion, but we're not sure where you're going to end up in terms of asset population

operating beyond it's useful life. Is that right?

MR. HIGGINS: Well, and again -- that is correct, Ms. Girvan. Again, though, we're not setting a particular objective with respect to the asset-past-useful-life measure. I think, to have an appropriate discussion about what the objectives are behind that $2.2 billion, we would need to go into the program evidence and examine the particular asset population and system area needs, including compliance needs, reliability needs, condition needs, all of which drive that total $2.2 billion number. So I think the answer to that is more so in the details. And then I would also say that inflation is also a contributing factor here. That should be considered, as well.

MS. GIRVAN: But isn't one of your goals to improve the situation where you have less assets in operation beyond their useful life?

MR. HIGGINS: Not at this stage in our assets renewal cycle, no. We have spent the last 10, 15 years investing heavily in bringing that number down. We're now at a place where we are looking to manage that risk. We do that primarily through the application of condition and reliability analysis and focusing on the worst assets.

But we have other priorities, modernizing the grid and growing the grid to meet different demands that we're trying to balance, so, in this, the specific objective for this rate period, is to maintain risk and maintain reliability through system renewal.

MS. GIRVAN: Okay. All right. Thank you. If you could turn now to 1B-CCC-13. And this is -- we had asked for, basically, how the forecast of the 4,400 DER connections was developed, and actually providing a list of these. And it's just -- I went to the evidence and I couldn't really see that. So, I'm just curious as to how you arrived at 4,400. Really, your forecasting. How you did that?

MR. HUNTLEY: Thank you for the question, Ms. Girvan. The DER forecast has three components. There is the renewable, non-renewable, and battery energy storage portions of it.

The forecast itself was developed considering, first of all, the committed pipeline of projects that are planned in this -- in the rate period, as well as the historical trends associated with the specific DER technologies. Some lean-year trending was undertaken, as well as some logarithmic trending to arrive at a forecast that we think is consistent with both historical behaviour, as well as future connections with respect to specific technologies.

MS. GIRVAN: So, how do you gauge in terms of assessing how many requests you're going to get from customers? How do you figure that out?

MR. HUNTLEY: We based that on historical and current trends that we are experiencing with respect to that technology.

MS. GIRVAN: Okay. So, what's the overall annual cost each year of the DER connections of the 4,400 spread over

five years?

MR. HUNTLEY: The annual cost?

MS. GIRVAN: Mm-hmm.

MR. HUNTLEY: DER connections are cost-recoverable. So, there is -- there are no -- there's -- there are no net costs to the program with respect to DER connections.

MS. GIRVAN: Okay. All right. Thank you. Could you turn to 1B-CCC-30, please. And I guess I wasn't clear here how the results of the future energy scenarios model impacted your rate plan.

MR. HIGGINS: Ms. Girvan, I'll try to be concise. The future energy scenarios was a set of what if scenarios capturing different potential pathways along the decarbonization journey and how the energy system might transform, and how that could impact us locally here in Toronto on the electricity system.

At the end of the day, those scenarios helped us in a couple of ways. One is they gave us a credible view of what the range of potential outcomes could be over the medium and very long term, and they helped us understand the extent to which those scenarios would diverge over time, giving us a range of the uncertainty that we're dealing with, and a better sense of how to monitor for how that uncertainty is ultimately unfolding in real time.

And so, the main way that it sort of directly impacted the investment plan was by assisting us with understanding whether or not our least regrets approach to planning investments was appropriately calibrated, and ultimately

was used to assess whether or not certain investments on the margins would be included or if they could be deferred.

MS. GIRVAN: Okay. All right. Thank you. Could you turn, please, to 1B-CCC-37. And it does say it's both panel 1 and 3, and I figure, Mr. Higgins, you can probably help me with these answers. So, I'm trying to understand your demand related programs, and I'm also trying to understand the demand related variance account.

So, what I was trying to get at, if you just scroll down, is I wanted to look at what you actually proposed, and I think it's comparing table 1 and table 3. What your forecast was in the last planned period, 2020 to 2024, and then in table 3, what your -- what was approved there and then, sorry, in table 1 -- is that correct, is that your actuals versus forecast, table 1 versus table 3?

MR. MUNDENCHIRA: Yes, that's correct.

MS. GIRVAN: Okay. And am I correct that the reason why you want the demand related variance account is because of the variability in these particular items?

MR. MUNDENCHIRA: Yes.

MS. GIRVAN: And is it most specifically with respect to customer connection? I sort of look at that particular item as one where you had more variability than any of the others.

MR. MUNDENCHIRA: That is correct with regards to the 2020 to 2024 rate period, customer connections did experience a significant variance.

MS. GIRVAN: And what was the reason for that

variance?

MS. NARISETTY: I can help address that. And if I can take you to the evidence, exhibit 2B, section E5.1, page 19. At the top, so starting at line 1, we discuss the expenditure and the customer connections segment, and how it's driven by a number of factors. And notably external factors, such as economic drivers, the actual connection that may be requested, the expansion work that may be required, the various policies around infrastructure and community projects as well as the ongoing energy transition that leads to a lot of variabilities in the program.

MS. GIRVAN: Okay. But you didn't really experience this much variability in the other items, did you?

MR. MUNDENCHIRA: To clarify, the other programs?

MS. GIRVAN: Yes. The ones listed in the interrogatory response.

MR. HIGGINS: Ms. Girvan, maybe just to clarify a little bit what we mean by variability. I think, you know, what you're seeing in the historical tables is -- I don't know if this is what you're referring to or not, so you can tell me. But I think what you're referring to is sort of an annual up and down sort of variability?

MS. GIRVAN: Well, variability actually between Board approved and actuals.

MR. HIGGINS: Okay.

MS. GIRVAN: And in customer connections I can see the pattern, it was quite significant, but I don't see it as much in the others, that's all.

MR. MUNDENCHIRA: Ms. Girvan, just to clarify, it is correct the connections is the most significant variance, it's about $160 million. Load demand as well is significant, it adds up to approximately $124 million. So, it's fairly close, they are the two biggest variances in the last five year period.

MS. GIRVAN: Okay. Thank you. And is it my understanding that the account will be -- will it be revenue requirement? So, it includes both capital and operating cost with respect to these items?

MR. MUNDENCHIRA: Correct.

MS. GIRVAN: And it's just these items?

MR. MUNDENCHIRA: Yes. There's -- so I think the tables we referred to in the discussion so far were the capital. So, the OM&A will also be there, which is table 2 and 4.

MS. GIRVAN: Okay. So, this captures everything you're seeking approval for in the DRVA?

MR. MUNDENCHIRA: Yes, the programs, yes, these are the programs.

MS. GIRVAN: Okay. Thank you. I just wanted to be clear.

MR. Murray, it's probably a good time for a break, the eclipse?

MR. MURRAY: We will take a break now, do you want to come back for 3:25.

MS. GIRVAN: 3:30?

MR. MURRAY: Okay. 3:30, we'll go back.

--- Recess taken at 3:00 p.m.

--- On resuming at 3:31 p.m.

MR. MURRAY: We're back with the technical conference, Ms. Girvan. You can continue with your questions.

MS. GIRVAN: Thank you. The next question is with respect to 1B-CCC-42. And on the list of interrogatories, it says it's this panel, and I am assuming, Mr. Higgins, you can probably answer this. It's just about some of the innovation that has gone on in the past.

And I just -- if you can scroll down to page 5 out of 6? I am just curious about the Etobicoke demand response pilot. That's something that was undertaken in the past, during the past rate plan. And it was funded through rates and funded through the grid innovation fund, and it looks like it's continuing into the new rate plan period?

MS. MARZOUGHI: So I can help answer that question. So the Etobicoke demand response pilot is essentially building on top of the local demand response program, which is running during the current rate period. The pilot portion, which as noted is funded through the ISO and OEB sandbox -- the IESO Grid Innovation Fund in collaboration with the OEB sandbox.

That portion does not continue into the rate period, into the next rate period. However, the local demand response program does. And that program is in the non-wire services -- the non-wire solutions narrative, which is section -- exhibit 2B, section E7.2.

So the pilot portion does not continue, but the program itself does continue.

MS. GIRVAN: So why wouldn't the program, going forward, be funded through the new innovation fund, the $16 million?

MS. MARZOUGHI: So the local DR program is not considered a pilot. It has been running since 2018. It started in the 2015 to 2019 rate period, and it's a core part of our plan at this point in our tool box for planning in our investment planning process. So that's why it's not considered as part of the innovation fund.

MS. GIRVAN: Is the $5.7 million specific to Etobicoke?

MS. MARZOUGHI: So the $5.7 million relates to the future program, which actually does not continue. It's not in Etobicoke necessarily; there are some stations that are targeted that are in the Etobicoke area. But again, the pilot refers to specifically the Manby and Horner stations that are targeted during this rate period, which is why it's called the Etobicoke demand response pilot.

MS. GIRVAN: Okay. Could you just scroll down to the next page, please? And I am curious about the process automation project. Can you help me with understanding that?

MR. KEIZER: I think that's a question for panel 2, Ms. Girvan.

MS. GIRVAN: It is?

MR. KEIZER: Yes.

MS. GIRVAN: Okay. All right. Thank you. Sorry, I'm just looking through my notes.

Okay, could you please turn to 1B-CCC-44, please. And there are a couple of questions here. If you can scroll down, this is about the grid modernization strategy. Keep scrolling down. Yeah. So, in question C, we had asked whether Toronto Hydro is collaborating with other utilities. And I know for example, being involved in both these cases, both PC Distribution Inc. and Elexicon Energy Inc. have undertaken similar projects. And it says that Toronto Hydro hasn't consulted with these utilities, and I am just trying to understand why not.

MR. HIGGINS: We haven't consulted, sort of one on one, in a particular sort of project context or anything on the grid modernization strategy. Obviously, we are aware of the plans they put forward, and some of the details of those plans and what the intended benefits are.

But when it comes to more of the technical side and the planning side and the strategy side, we engage more broadly with a number of different industry peers, not just in Ontario, but in jurisdictions that are actually maybe further ahead on some of this stuff. And we take lessons from them in designing these programs.

So it's not that we wouldn't -- I mean, we may, in the future, consult with these utilities. We just didn't in the lead-up to this particular strategy.

MS. GIRVAN: Okay. And is your project similar to what they have undertaken.

MR. HIGGINS: I believe there is some overlap. I know many utilities who are going through these journeys are focused on distribution automation, FLISR adding more switching capabilities to their systems, enabling more DER connections.

So I suspect -- well, I know that the themes are -- there would be a broad overlap, though they wouldn't be identical.

MS. GIRVAN: Okay. Could you please turn to CCC-46, please. And this is about the innovation fund. Is this for this panel?

MR. KEIZER: The projects are, but the fund itself is for panel 3.

MS. GIRVAN: Okay. But is the overall responsibility for that program within the capital planning group?

MR. KEIZER: The technical side is, I believe.

MS. GIRVAN: So, Mr. Higgins, you are involved in this in terms of selecting the projects?

MR. HIGGINS: Yes.

MS. GIRVAN: Okay. If you could please turn to 1B-CCC-48. So I am just trying to understand the sort of process that you undertook in developing this overall plan. And the first thing that you say is that you constrained your initial plan by approximately $480 million. And I may have missed it, but do we have a calculation of that and how it was derived? And this was prior to the customer engagement process, I believe.

MR. HIGGINS: Yes, if you just give me a moment. So

if we can go to 2B-SEC-54, this table 1 delineates all of the reductions that would total to that $480 million.

MS. GIRVAN: Is the table longer than this? Okay. Sorry. Okay, so does it say $480 million, down below?

MR. HIGGINS: If you look at the last row, you will see $4.519 billion versus $4.038 billion. That is subject to check -- that should be.

MS. GIRVAN: Okay. All right.

MR. HIGGINS: Yes. The math should be correct. Yeah.

MS. GIRVAN: Okay. Thank you. So that's the first thing you did. And then you also refer to, in my original IR about the $65 million that you are saying is an upfront benefit to customers in terms of -- we had asked you really about price for customers is a top priority, price and reliability. And you said, okay, first of all, we cut million. Then we also are guaranteeing an upfront benefit of 65 million.

But it's my understanding that potentially that $65 million could be clawed back. That's correct, right?

MR. HIGGINS: Yes. I just note that if we are going to get into the design of the performance incentive mechanism, it might be better for panel 3.

MS. GIRVAN: Yeah. Anyway, that's fine, that's fine. I have to be careful not to cross-examine. Okay.

And then further down in that interrogatory again, we are still at No. 48. And there are two things that I am just asking you about, just to confirm that, with respect to the 7 percent rate impact, you didn't discuss that, and

Innovative didn't discuss that with your customers. Is that correct?

MR. KEIZER: I think the scope of the customer engagement, Ms. Girvan, is probably panel 3.

MS. GIRVAN: Panel 3, okay. Okay. Then, you refer to this: Following the customer engagement, you again reduced your capital budget by an additional -- capital plan by an additional $70 million. How did you arrive at the $70 million level?

MR. HIGGINS: So that answer is probably best found, again, in 2B-SEC-54, as you move now to table 2. Same idea, it shows the program-by-program changes that happened in that final phase, which, if you look at the final row, will give you that $70 million difference. Oh, sorry. Sorry, let me clarify that.

The $70 million, rather, that refers to specific reductions that were made -- sorry, reductions that were made in programs specifically in response to customer engagement feedback. So the overall reduction -- I should clarify -- between the draft plan and final plan was around $40 million, and that's because, some other programs, the costs went up for various reasons that are articulated in this table.

So the $70 million -- if you just give me a second. So the $70 million -- and this is articulated in section E2.1.2 of the distribution system plan, where we talk about customer engagement, but, just to summarize, the $70 million reduction consisted of deferring the second

phase of Basin TS, which is the $35 million reduction, deferring $20 million worth of station switch gear renewal investments, and a $16.5 million reduction to some of the core general plant programs. And, as we discussed in that section of the DSP, that was tied to specific feedback we got from customers regarding preferences in pacing.

MS. GIRVAN: Okay. Could you turn to 2A-CCC-52. I'm just trying to understand this category of contributions and grants, and I note that, in the years 2020 to 2024, contributions and grants went from $334 million to $898 million. I was looking at what the actual forecast versus actuals for each of those four years was with respect to contributions and grants. I don't think I have that.

MR. MUNDENCHIRA: I don't believe we have a comparison laid out as such in evidence, but it can be provided.

MS. GIRVAN: Okay. Could you provide that, please?

MR. MUNDENCHIRA: Yes.

MS. GIRVAN: And what happens with respect to contributions and grants, for example, if, let's say, the forecast for a year was $100 million but in fact the actual contributions and grants were $200 million? Where does that --

MR. MURRAY: Ms. Girvan, can we pause before we move on? I believe they provided an undertaking, so let's just get that a number.

MS. GIRVAN: Oh, I'm sorry. Yes.

MR. MURRAY: That will be undertaking JT1.17.

UNDERTAKING JT1.17: IN 2A-CCC-52, IN THE CATEGORY OF CONTRIBUTIONS AND GRANTS, TO PROVIDE ACTUAL FORECAST VERSUS ACTUALS FOR 2020 TO 2024.

MS. GIRVAN: Thank you.

MR. MUNDENCHIRA: For your question, Ms. Girvan, I will just repeat the example: So, if the actual capital contributions and grants were lower than what was forecasted, what would happen?

MS. GIRVAN: I think I went the other way.

MR. MUNDENCHIRA: The other way around. Okay, sorry. I misunderstood. Okay. So, if contributions and grants were higher than what was approved, then, by itself, that would cause rate base to be lower, amortization of capital contributions to be lower. However, the capital contributions and grants, they go hand in hand with gross expenditures of Toronto Hydro from programs such as customer connections or externally driven capital projects, so in general they do need to be looked at hand in hand since it is on a net basis of the cost versus capital contributions that rate base is impacted.

MS. GIRVAN: Okay, so it is not like a windfall to the utility in a given year if they're higher?

MR. MUNDENCHIRA: I would not frame it like that. Those contributions are to offset costs. So, generally, the costs also would go in a similar proportion, higher or lower.

MS. GIRVAN: Okay. And I guess it's my understanding that -- are you the -- sorry. The contribution and grants,

that's going to be part going forward with covered through the demand-related variance account?

MR. MUNDENCHIRA: Correct. The two primary programs that drive capital contribution and grants are proposed to be in that demand-variance account, so, essentially, it would for the most part be captured there.

MS. GIRVAN: Okay. Thank you. Could you go to 2A-CCC-53, please. Oh, 53, sorry. Thanks. I just want to confirm, so this is probably just me not fully understanding. So, with respect to the concentric depreciation study, it lowers your depreciation expense. Is that correct?

MR. MUNDENCHIRA: Correct. Overall, it lowers it.

MS. GIRVAN: Okay. All right. Thank you. And could you -- I just have a couple more questions. This is 1B-STAFF-15. So they asked you to run some scenarios in terms of what the impact would be under both the current IRM framework and under straight IRM scenarios. If you go further down, it says that, under your current framework, it would result in an 8 percent deterioration and system reliability by the end of the rate period. I'm just wondering how you derive that 8 percent.

MR. HIGGINS: Just give me one moment, Mr. Girvan, I can -- Ms., sorry, Ms. Girvan. Sorry, it's late in the day, Ms. Girvan. I can find you the correct reference. Okay, and apologies for that again. I've been saying "mister" all day.

If I can take you to 1B-EP-15, Part A, this asked for

the calculation, so we provided a description. So the 8 percent deterioration in system reliability is the percent difference between our actual historical five-year average for 2018 to 2022, and, the projected five-year rolling average at the end of the rate period under the IRM scenario, it provides the values there.

And then -- we don't have to go there, but, if you proceed to Exhibit 1B, tab 3, schedule 1, there is a further discussion of the spending assumptions that were made around an IRM scenario, so it does involve significant capex reductions across our program.

MS. GIRVAN: What's the comparable figure for the under your existing framework analysis? It's probably in here. I just didn't --

MR. HIGGINS: The reliability forecast?

MS. GIRVAN: Because this is IRM, not current frame.

MR. HIGGINS: Yes. Just a minute. I'm just looking for the interrogatory response where -- it's an SEC interrogatory response where we explain the reliability methodology, and I believe that's where we provided the updated chart, so just bear with me for one second.

MS. GIRVAN: Okay.

MR. HIGGINS: Okay. All right. If we can go to 2B-SEC-42. Hopefully this actually has the response that I'm looking for.

MS. GIRVAN: You don't have all of these memorized?

MR. HIGGINS: Not yet. By the hearing, perhaps. And...

MS. GIRVAN: If it's in an SEC interrogatory, I can find it later.

MR. HIGGINS: It is -- sorry, the chart is there, but I'm just realizing the specific five-year average value you're looking for may not be. I'm happy to respond to this one through undertaking if that's more efficient.

MS. GIRVAN: Thanks, that would be great. Thank you.

MR. MURRAY: That would be undertaking JT1.18.

UNDERTAKING JT1.18: TO EXPLAIN THE IMPACT ON RELIABILITY, THE PERCENTAGE AMOUNT ASSUMING A SCENARIO UNDER THE CURRENT RATE FRAMEWORK, BECAUSE THE 8 PERCENT RELATES TO THE IRM FRAMEWORK.

MS. GIRVAN: I just have two more questions.

MR. KEIZER: Sorry -- can we just make sure we got the --

MS. GIRVAN: Sorry.

MR. KEIZER: That was, kind of, a protracted exchange, maybe we can just be clear what the undertaking is?

MS. GIRVAN: Sure. It's the impact on reliability, the percentage amount assuming a scenario under the current rate framework, because the 8 percent relates to the IRM framework. Just an IRM plan. You've got that?

MR. HIGGINS: Yes. So, just to parrot that back one more time. So, you're looking for the 5 year average associated with the plan?

MS. GIRVAN: The previous plan. The plan that you're on now, that Staff interrogatory took you through a couple of scenarios, and said what's the revenue requirement

impact of IRM, and then your current plan not your proposed plan. I think that's what it said.

MR. HIGGINS: I apologize, can we go back to that interrogatory? I'm just getting a bit turned around on --

MS. GIRVAN: Maybe I read it wrong. It was a staff one.

MR. KEIZER: I think it was staff 15, is that right?

MS. GIRVAN: Now I forget. Hang on.

MR. HIGGINS: 1B-Staff-15, I think it was.

MS. GIRVAN: Yes. I think that's what's asked in question B.

MR. MUNDENCHIRA: Ms. Girvan, just to clarify the question, you're asking about the rate framework that exists in 2020 to 2024 as opposed to what's proposed in to '25 to '29?

MS. GIRVAN: Yes.

MR. MUNDENCHIRA: Give us a moment.

MR. HIGGINS: Yes, we haven't done that analysis.

MS. GIRVAN: Okay. All right. Thank you.

MR. MURRAY: Sorry, does that mean you are giving an undertaking or no? So, the undertaking is...

MR. HIGGINS: No undertaking.

MS. GIRVAN: Oh, you haven't done that, okay, sorry. Okay. Just two more questions. If you can turn to 1B-Staff-99. And there's two sort of discussions here, one is about your internal innovation sandbox, and it says it was self-funded, what does self-funded mean?

MR. HIGGINS: I think this might be a panel 2 question

or 3.

MR. KEIZER: I think it's a panel 3 question.

MS. GIRVAN: Okay. And I have another question on the innovation fund, but I should leave that to panel 3 as well?

MR. KEIZER: If it relates to the fund and the structure of the fund, yes.

MS. GIRVAN: Yes, it does. Okay. Thank you. Those are my questions.

MR. MURRAY: Thank you, Ms. Girvan, next up is PWU, Mr. Rosenbluth. I believe you're online.

MR. ROSENBLUTH: Hi, thank you. Is my audio coming through okay?

MR. MURRAY: Yes.

EXAMINATION BY MR. ROSENBLUTH:

MR. ROSENBLUTH: Great. I would like to start with 2B-PWU-3. Thank you. And top of the page at about line 6, there's a reference to a forecast of approximately 24 percent lower than planned. So, my question is simply what is the dollar amount in response to the 24 percent?

MR. HIGGINS: If you bear with us, we can do the math here.

MR. ROSENBLUTH: Thank you. I'll take an undertaking as well if it's easier.

MR. KEIZER: Sorry, can you just articulate the undertaking, please?

MR. ROSENBLUTH: Just to advise of the dollar figure that corresponds to the 24 percent reference at line 6 of

this page.

MR. KEIZER: Okay.

MR. MURRAY: So, that's an undertaking or are we doing fast math?

MR. HIGGINS: Yes, sure. We'll take the undertaking.

MR. MURRAY: That will be undertaking JT1.18.

UNDERTAKING JT1.18 (2): TO ADVISE OF THE DOLLAR FIGURE THAT CORRESPONDS TO THE 24 PERCENT REFERENCE AT LINE 6 OF 2B-PWU-3.

MR. ROSENBLUTH: Staying on the same page, we see two tables a bit lower down here. Just a quick question. The table 2 is labelled as downtown. Table 1 is not labelled. I think it is the response as it relates to Horseshoe, and I just want to confirm that.

MR. HIGGINS: That's correct, yes.

MR. ROSENBLUTH: Thank you. Similar question to my first one in relation to the dollar value for each of the percentages listed in both of these tables. Could I get that by undertaking, please?

MR. HIGGINS: So that's something that we don't have. So just to clarify, this is volumes of work, and so in this case, like the dollars that were deferred in the program were referenced in the preamble related to the previous undertaking. This is the volumes of work, so there's not a specific dollar amount associated with this.

MR. ROSENBLUTH: But the data -- fair enough, in terms of these tables may not speak to cost and may speak to volume. But would that data be available?

MR. HIGGINS: No. So, we do have the program level preponderance variances, obviously. For the asset class by asset class level, I'll try to explain.

What makes it tricky is we would have to go back and assume some kind of unit cost. The reality is we forecasted these at the time, without full project details. And so to say that a specific dollar amount associated with these units has been deferred, that would be a bit of an after-the-fact exercise. So I don't think it's possible.

MR. ROSENBLUTH: Okay. So just so the transcript is clear, I think what you are say suggesting for these two tables, it is not reasonably possible to translate the percentages listed here into dollar amounts?

MR. HIGGINS: No. It would be an artificial estimate based on some chosen unit cost. So, no.

MR. ROSENBLUTH: Okay. So then what is the metric that this table is expressing in?

MR. HIGGINS: For example, in the first table, total cable is circuit kilometres. So we deferred 12 circuit kilometres. And then transformers and switches would be units, so just number of transformers and numbers of switches.

MR. ROSENBLUTH: Okay. Thank you. And the deferred projects referenced in these two tables, are they included in the currently proposed plan for the 2025 to 2029 period?

MR. HIGGINS: So the way we did this analysis for these tables is we looked at the number of units that were in the original rate filing for 2020 to 2024, and compared

that to the number of units that we are on track to replace in those same categories.

Now because, again, the units when we are looking out five, six, seven years are not specifically known, we don't know the exact equipment ID and which assets we are going to do, we wouldn't be able to go in and say, you know, "Transformer No. XYZ has been pushed from 2020 to 2025."

So doing a reconciliation on a unit level like that I don't think would be possible. But directionally, it is the case that the fact that we did not achieve as much work in this rate period, that fact does have an influence on how much the need is on the system in the next rate period.

MR. ROSENBLUTH: So, in terms of that directional point that you just made, is there sort of -- if I am trying to understand that with more precision, is there a way you could express it differently than these two tables that would offer more precision in terms of what is being proposed in the current application?

MR. HIGGINS: I don't think so, no. Again, it comes down to how we determine the budgets for long-term plans like distribution system plans. It's volumetric in nature; it is not project based. So it would be challenging. I don't think that's feasible, no.

MR. ROSENBLUTH: Okay. So in terms of -- I mean, this question and this answer, what we were asking about was to identify and list the investments that were deferred to what is effectively the current application. And these are the tables we get back. And I hear your point about,

essentially, this is -- am I understanding correctly that this is essentially as precise as you can be for answering this specific question A listed here? Is that fair?

MR. HIGGINS: Yes.

MR. ROSENBLUTH: Okay, thank you.

MR. RUBENSTEIN: Sorry, Mr. Rosenbluth, I was just wondering if I could ask a question of the panel, just to clarify a response they provided to you?

When you were asked to translate this into essentially the dollars, and you said you couldn't do that because you would have to go back in time and essentially create a unit cost, I was under the impression, and you can correct me, for the budgeting purposes -- so how you would have budgeted in the last application -- you were, because you have -- these are programmatic programs where you don't actually know at this time the specific, you know, polls you are going to replace or, for here, the underground assets projects, that's -- you essentially had to create a unit cost or some sort of proxy metrics for the costs.

So it's not clear to me, what is the disconnect of why you essentially wouldn't be taking these numbers and multiplying it by whatever unit cost you had used in that last application?

MR. HIGGINS: Yeah, that's a reasonable question, Mr. Rubenstein. We could go back and take the unit cost from the previous rate application and apply them here. The issue is I don't think that they would add up to the amount of money that has actually been deferred in the program.

And the reason for that is the actual unit costs that we incurred during the program have generally gone up. And so we have spent basically more money per unit.

So that's where it's like, do we use the new unit cost? Do we use some kind of new unit cost that's higher? Do we use the original unit cost? There's no fixed point on which to do the analysis.

MR. ROSENBLUTH: Would it be possible then, just building on Mr. Rubenstein's question, to provide that form of analysis with a best estimate based on current figures?

MR. KEIZER: Sorry, I am trying to understand what you mean by the best estimate or best what's --

MR. ROSENBLUTH: Well, I understood Mr. Higgins to be -- his response was to the effect of, you know, we could give you the numbers that Mr. Rubenstein was talking about, but it wouldn't be accurate because the numbers have changed.

So I guess what I would like to know is could we essentially answer Mr. -- provide an analysis using the approach suggested by Mr. Rubenstein, but with the most accurate figures available to the utility or in the utility's view? And if that involves an element of estimation, then that can be noted.

MR. KEIZER: And I guess I just want to understand. So, to what end, I guess, given the fact that the issue at hand is the programmatic variance that appears overall? So I am not sure what that value necessarily gives you.

MR. ROSENBLUTH: Fair enough. I mean, what I am

really trying to get at is to put the best possible dollar numbers on to the tables that we are looking at here. I mean, that's an important analysis or exercise. So I am just sort of -- I have been told that's not really possible, which is fair. I am just trying to sort of explore whether there might be an available approach.

MR. HIGGINS: I think maybe one way that we can look at this, we will have to take it back to the planners to see if it all lines up. But we could apply the unit costs that we used in this rate application to these units. If you want to get a rough sense of sort of the current value of this work, that would probably be feasible.

MR. ROSENBLUTH: Right. And am I right to assume that that, those metrics or figures would include basically the utility's current estimate of price with inflation accounted for, et cetera?

MR. HIGGINS: It would include all the same assumptions that went into this distribution system plan.

MR. ROSENBLUTH: Yes. So, I mean, if that's an offer of an undertaking, I will happily take it.

MR. HIGGINS: Yeah. We will look at that and try to provide it. Yeah.

MR. ROSENBLUTH: Thank you.

MR. MURRAY: That will be undertaking JT1.19.

UNDERTAKING JT1.19: TO RESPOND AGAIN TO 2B-PWU-32.

MR. ROSENBLUTH: Thank you. Last question on this page: In terms of the cost of undertaking these deferred projects in the planned rate period, would that cost be

higher or lower than had the same work been undertaken in the prior rate period, I mean, at least having regard for Inflation?

MR. HIGGINS: Yes, we expect that the cost would be higher.

MR. ROSENBLUTH: And direction to this, can you give me a sense of magnitude that you would estimate, in terms of that delta?

MR. HIGGINS: So if we can just go to, sorry, 2B-Staff-169? So just to caveat this, I guess specifically with respect to the units that are in these tables, we would -- to do the analysis properly, we would have to kind of know when were there originally planned and then do the calculation on that basis. And even then, there is a number of assumptions that would have to go into estimating how much more expensive it will be.

But in 2B-Staff-169, we were asked to explain some of the drivers of the cost increases in the renewal programs; I believe this is with respect to the overhead program? System renewal in general. As we noted, if you scroll down to the inflation section, just based on this rough estimating approach that we took, we believe that, you know, roughly 60 percent of the overall increase in the system renewal program over the previous period is about -- sorry, yes, about 60 percent, sorry, is due to inflation. And so that gives you maybe a sense of the magnitude just between the two rate periods, based on, you know, admittedly the somewhat unique inflation experience that

we've had over the last five years.

MR. ROSENBLUTH: So but it is not 60 percent of that increase. You're not saying there that the work -- the answer to my question is that it just would have been straight 60 percent higher, are you?

MR. HIGGINS: No, not necessarily. We do require a more detailed analysis.

MR. ROSENBLUTH: Right, so does this -- I mean, I guess my question then is: Having regard for the information we're looking at in the staff response and, you know, subject to the assumptions that you've just referenced, does this information shed any further light on your ability to respond to my prior question in terms of directionally what would the magnitude difference have been if that deferred work had been done last period versus this period?

MR. HIGGINS: It's one data point. I think it provides a sense of the scale of inflation that we've seen across the board.

MR. ROSENBLUTH: Okay. I'll move on. Thank you. Can I go back to 2B-PWU-4 now and just up at the preamble. Similar question: There's a reference at line 6 to "18 percent lower." Happy to do this by undertaking. I'm looking for what the dollar value is that corresponds to the 18 percent.

MR. MUNDENCHIRA: The table reference in the response, I believe, is based on our pre-filed evidence, which included a 2023 forecast as well as 2024 forecast. I do

have the latest version, with 2023 actuals and 2024 updated forecasts. So the percentage is 16 percent, just to make sure we're on the same page --

MR. ROSENKRANZ: Okay.

MR. MUNDENCHIRA: -- and the updated percentage, and the corresponding dollar amount is $42 million.

MR. ROSENBLUTH: Thank you. I wanted to ask similar questions about this table 1 as we had just explored on the prior tables, on the prior question. Maybe just to speed it up, I mean, could I get any undertakings that were given in respect of tables 1 and 2 on 2B-PWU-3? Could I get the same undertakings on this table that we're currently looking at?

MR. HIGGINS: So, just to be clear about that, you're asking -- I think the one undertaking was applying the most recent DSP unit cost to these volumes, right?

MR. ROSENBLUTH: Yes.

MR. HIGGINS: Yes, we can do that.

MR. ROSENBLUTH: And I take it your answers would be similar in that, so, A, is it possible to put a dollar value on the percentages in this table?

MR. HIGGINS: I think that's what --

MR. ROSENBLUTH: Oh, sorry. Other than whatever is going to be in the answer to the undertaking you just described.

MR. HIGGINS: Yes, no, the answer is the same on that one.

MR. ROSENBLUTH: Right. Okay. And then would it be

the same in terms of it's not possible to provide a precise answer for how much of this deferred work forms the subject of the current application, or is it possible?

MR. HIGGINS: We would face the same challenges here.

MR. ROSENBLUTH: Right. And same answer generally in terms of calculating the cost of doing this deferred work in the current rate period as opposed to the prior?

MR. HIGGINS: Same response as before, yes.

MR. ROSENBLUTH: Thank you.

MR. MURRAY: So we'll give that an undertaking number, the earlier thing about the unit cost in this application multiplied by the volumes in the table, and that will be undertaking JT1.20.

UNDERTAKING JT1.20: RE TABLE 1 IN 2B-PWU-3, TO REFORMULATE WITH THE UNIT COST AS DESCRIBED PREVIOUSLY, MULTIPLIED BY THE VOLUMES IN THE TABLE.

MR. ROSENBLUTH: Thank you. I would like to move now to 2B-PWU-9. So there's reference in the preamble, line 6, to a 5-percent variance, essentially, and then the response goes on to adjust that from 5 percent down to 4.8 percent, $72.9 million. Is it fair to assume that this variance, the $72.9 million, represents the work that was deferred for the current period, or were there any cancelled projects or anything like that?

MR. HIGGINS: I think it would be fair to say that it mostly represents deferred work, yes, but it is possible that there are cancelled projects, as well.

MR. ROSENBLUTH: Can we, perhaps by undertaking, get

some more precision on that, perhaps a percentage of this $72.9 million that arises out of deferred work?

MR. HIGGINS: So, just to clarify, Mr. Rosenbluth, that $72.9 million, that's sort of the net result of all the changes that happened in the program. So there would be projects that increased in cost; projects that decreased in cost; projects that were deferred; projects that were cancelled; projects that were pulled forward from, you know, 2025 into 2024, for example. So I'm not sure there's a clean kind of analysis that can be done around that, especially when, again, we would not have had the full list of projects when we generated the budget in the first place.

MR. ROSENBLUTH: Okay. But just -- so I think what you're saying is sort of that there's noise in both directions, if that's a fair way of paraphrasing. I guess I'm just trying to isolate the dollar value that is referable to deferred work, and I'm guessing that the answer is not $72.9 million based on the answers you've given. So is it possible to isolate that figure, regardless of the other noise?

MR. HIGGINS: No, for the reasons I cited. We would need to know what the full list of projects was going to be and their estimates for the full, you know, period of the distribution system plan and then sort of true-up on that basis, which is not possible.

MR. ROSENBLUTH: Okay. So then, backing up a couple of questions, you said a moment ago when I asked what

percentage of the 72.9 arises out of deferrals, I think you said something to the effect of, most of it, but it may be some cancellations.

Maybe I'm just not asking the question the right way. Is it possible to provide anymore precision to that answer or anymore detail?

MR. HIGGINS: Yes. So maybe I can just flesh out that previous response with my later response. You know, it is a net-negative variance, obviously, so there was less money spent, and so, to the extent that it is a negative variance, that would imply, obviously, that work was deferred. And we can see that when we look at the volumes from your previous interrogatory that we discussed.

However, as I mentioned, there are plusses and minuses, and cost variances are part of that, as well, so, yes. So again, because we don't have the project list, we can't offer anymore precision here.

MR. ROSENBLUTH: Okay. Okay. I'm going to move on, then, to 2B-PWU-14, and this set of questions really deals with the four interrogatories, including this one, so 14, 15, 16, and 17. Maybe I can just sort of ask, rather than having to repeat myself, I can ask the questions on this one, and we can sort of treat them as having sought the same information with respect to the other three.

And so what I'm after here is we have this figure -- I think that's Figure 9, although I may be blind. The chart we're looking at, we were seeking the tabular data, and we didn't get a response.

So I guess my question is, I mean, surely the tab, the numbers exist in some form to be able to generate a chart like this, so can we get that by way of undertaking, the data that gave rise to these charts?

MR. HIGGINS: Yes, and apologies, I think that was just lost in the different IR responses.

MR. ROSENBLUTH: Okay. That's fine. Thank you. And that, obviously, applies to all four relevant charts, as I said.

MR. HIGGINS: And just to clarify, and I don't want to interrupt, sorry, but just that will not include the scenario that was requested around with investment? It will just be the data behind the existing chart.

MR. ROSENBLUTH: Yes, I'm just asking for the actual data, that's right. Thank you.

MR. MURRAY: Mr. Rosenbluth, before we move on, we want to make sure we give it a number, so that will be JT1.21.

UNDERTAKING JT1.21: TO PROVIDE THE DATA IN THE TABLE AT FIGURE 9 OF 2B-PWU-14.

MR. ROSENBLUTH: Thank you. And in terms of knowing, you know, which specific assets are going to be replaced as they age and so on, and I appreciate the response, this is a difficult analysis. So, I guess sort of more generally, at a directional level, is it fair to say that the share of assets passed their useful life in 2029 will be higher at the end of 2024, assuming that the proposed plan is approved? Or I should say fair to say it will be lower. I

guess the question is: Would it be higher or lower if the plan is approved?

MR. HIGGINS: We haven't done that analysis asset class by asset class. This ties into the discussion from earlier today around, you know, to do that analysis we would need to have a list of the assets we're looking to replace and a high degree of confidence around that list, which we don't have at this point.

MR. ROSENBLUTH: Can we say though, by way of reasonable estimate, whether that share of assets past their useful life increase or decrease by the end of 2029 relative to the end of 2024, based on the -- assuming the current plan is approved? Could I ask, you know, some form of analysis to done to provide an estimate in that regard?

MR. HIGGINS: Yes, if we were going to do that we would need to define what the assumptions are going to be behind that analysis, because we don't have a model to do that analysis at this time. We did provide some the additional commentary in 2B-SEC-44 around condition, but we haven't done that analysis on age.

MR. ROSENBLUTH: Sure. But, I mean, let me just try one more approach. Sitting here today, based on what you know about what the assets that are out there, I mean, what's your -- do you have an estimate sitting here today, appreciating there's a lot of uncertainty, and you can use different assumptions, but just directionally, would it be higher or lower 2029 versus end of this year?

MR. HIGGINS: No, I think it's important just to note

that we're not setting targets for age demographics. We're taking age demographics into consideration, particularly looking at assets that are operating well beyond their useful lives, but we're not, we're not setting particular targets for age demographics, and therefore we haven't done the analysis.

MR. ROSENBLUTH: No, and that's fair, I'm not trying to imply that there needs to be any significance, necessarily, one way or the other, I'm just asking the factual question. So, I guess, just to try to repeat, regardless of what you may choose to draw from this, is it your sense today that the share of assets past their useful life will be higher in 2029 than it will be at the end of this calendar year, if the plan is approved?

MR. HIGGINS: It's going to depend on the asset class, and even then I can't, sitting here today, say whether it's going to be higher or lower. Our goal in general across the asset base is to maintain asset risk. But we can't assess that by looking just at age, nor can we assess it by looking just at condition. There are criticality factors, and performance factors, and a number of other things that go into that analysis. So, I'll leave it there.

MR. ROSENBLUTH: Okay. Those are my questions. Thank you very much.

MR. MURRAY: Thank you, very much, Mr. Rosenbluth. We're going to have a slight change in the schedule. So, next on the list will be Pollution Probe. Mr. Brophy, are you on the line?

MR. BROPHY: I am. Can you hear me?

MR. MURRAY: We can.

MR. BROPHY: Okay, great. I know there was a bit of a switch up, so sorry I couldn't join in person.

EXAMINATION BY MR. BROPHY:

Good afternoon, Panel, my name is Michael Brophy and I'm here on behalf of Pollution Probe today.

So, I'm probably, I guess, take us to the end of the day, which I think is about five, and then resume after Environmental Defence starts off tomorrow, I believe. Okay. So, for most of the questions, you probably won't have to pull up the interrogatory, but I'm happy if you want to just let me know if you need time to do any of that.

So, the first question relates to Pollution Probe five, where we asked if Toronto Hydro has a long term roadmap or equivalent for grid modernization out to 2040 or beyond, and we were referred to SEC-48, which then referred us to the distribution system plan in exhibit B, section 5. So, when I followed that trail. It just, kind of, laid out, kind of, the future, but it didn't indicate anything about long term roadmap. So, Is it fair to say that the answer is no there isn't a long term roadmap that's available?

MR. KEIZER: Sorry, Mr. Brophy, you said you were talking about Pollution Probe number 5?

MR. BROPHY: 5B, yes.

MR. KEIZER: 5B. Oh, I see it. Sorry, I see 5A

beside --

MR. BROPHY: Yes, there is no answer in there. It sent us to 2B-SEC-48, just to save you some time. Do you need some time, or...

MR. HIGGINS: We're just pulling up 2B-SEC-48.

MR. BROPHY: Okay, sure. Yes. And then that refers us back to the evidence.

MR. HIGGINS: So, Mr. Brophy, thanks for the question. Maybe just to add a little bit more colour to this response, I think what we were getting at here is, we have many of the elements of a roadmap within grid modernization strategies, so there's particular capabilities that are identified within that roadmap that we are looking to build over the next five years. And then there is some commentary in that strategy around how those capability building efforts lead to more longer term needs and capabilities that we need, or benefits we want to achieve even beyond 2030 as we lookout to potential high DER scenarios, and high growth scenarios, and how we can best deliver efficiency, and reliability, and access in that future world.

What we also mention in 2B-SEC-48 is the fact that we have specific technology roadmaps for more discreet initiatives, you know, within -- internally within Toronto Hydro, and it just depends on the initiative, and how mature it is, whether it has a roadmap or not. But, in general, for information technology and operational technologies they will have their own detailed roadmaps

that go out varying lengths depending on the nature of the work. We just don't have a -- to cut to the chase, we just don't have a single consolidated roadmap that corresponds to the grid mod strategy.

Mr. Brophy: Okay, I think I'll leave it there, that's my understanding, that there might be some pieces, but, yes, no overall roadmap as you mentioned.

Okay. The next one should hopefully be easy. So, again, I don't think you have to pull this up, but if you need to, just let me know. So, in Pollution Probe 3, Toronto Hydro provided the definition you're using for distributed energy resource or DER, and it gave us the link to the conditions of service where it lives. You're familiar with that? And I would note if you're looking, I think the footnote actually with the link was wrong, but Toronto Hydro was able to provide me the link that works, which was great.

MR. HUNTLEY: Yes, that's correct, Mr. Brophy.

Mr. Brophy: Okay, thank you for that. And then, Toronto Hydro indicated that although the DER definition that you have in your conditions of service is not as detailed as the definition in the national standard practice manual, or NSPM for DERs, that all the major elements in the national standard practice manual for DERs is covered in your definition. Do I have that correct? They are somewhat synonymous?

MR. HUNTLEY: Yes, that's correct.

MR. BROPHY: Okay. Thank you. And also, Toronto

Hydro indicated that if you need to adjust your definition of DER in the future, you are willing to do that. I believe you said that, is that correct?

MR. HUNTLEY: Are you referring to a specific section in the response, Mr. Brophy?

MR. BROPHY: Yeah. Well, I think it was in Pollution Probe 3, in the response. Sorry, I can just ask you the question, again. If there was a need to change that definition in the future, I assume Toronto Hydro would be willing to do that?

MR. HUNTLEY: It is the intention of Toronto Hydro to comply with the definitions that are appropriate to the codes, the Distribution System Codes.

MR. BROPHY: And if they need to change in the future, you would do that. Correct?

MR. HUNTLEY: If there is a revision to the code. Yes.

MR. BROPHY: Okay. So the definition in your conditions of service, are you saying that that's actually not a definition from Toronto Hydro, but you have cut and pasted it from a code? Is that what you are saying?

MR. HUNTLEY: We are saying that the definition is consistent with definitions that are applicable to the Distribution System Code.

MR. BROPHY: Okay. Yeah, that's my understanding, as well. Thank you.

And then as you know, DERs include a lot of different elements: CDM, storage, potentially generation. I won't

go through the full list. And I wanted just to confirm that Toronto Hydro is not aware of any restrictions that would block the regulated utility from supporting or enabling the broader scope of DERs.

Are you aware of anything that would block you from enabling or supporting those within the distributed -- or within the regulated utility?

MR. HUNTLEY: One moment, please.

MR. BROPHY: Sure.

MR. HUNTLEY: Thank you for the question, Mr. Brophy. Could you be a little bit more specific with regard to "supporting"?

MR. BROPHY: Sure. So I was trying to avoid the rabbit hole of, you know, whether you are allowed to invest capital as the utility, or just enable and support it so that customers can put them in outside. So I wanted to stay at that higher level, so we don't have to say who would actually do it.

But in the broader definition of DERs, are you aware of anything that would restrict the regulated utility from enabling those in your service Territory? So that could be through either installing them yourself potentially, if it was appropriate, supporting customers in installing them, having programs or incentives directly or via other parties like IESO, and supporting theirs, or doing your own.

You know, I think you have also talked about some of your set improvements that you are putting in place to enable DERs, so that would fit in as well.

Do you understand what I am asking?

MR. HUNTLEY: According to the elements of the plan we have put forward, Mr. Brophy, those investments are particularly targeted to enable the connection of DERs. They are consistent with investments we have made in the past, and we intend to continue to make those investments subject to board approval.

MR. BROPHY: Okay. So you are not aware of any barriers to the regulated utility proceeding with that approach?

MR. KEIZER: To the extent that the witness can answer, I don't know if there's any kind of statutory things or other legal aspects that he would not be aware of.

MR. BROPHY: Okay. Well, you know, again, if some come to mind, feel free to let me know. But I just wanted to make sure there was nothing you are aware of that would block you from doing any of those things. And it sounds like subject to validating the legality of it, there's nothing that comes to mind.

Okay. So I would like to just talk a bit about the information that was in 1B-Pollution Probe-7. And Toronto Hydro indicated that its system peak demand forecast is a gross forecast. And you indicate that gross forecast means that behind-the-metre energy distributed, energy resources are not considered as negative energy load or energy generation to reduce peak. And Toronto Hydro indicated that in order for those resources to be able to be relied

upon to reduce the peak demand forecast, they would have to be reliably aggregated and dispatched through demand responses, non-wire solution.

Does that sound right? I think you were talking about that this morning.

MS. MARZOUGHI: Yes, that's correct.

MR. BROPHY: Okay. That's correct. Sure.

So as you know, there's a lot of customers putting in DERs, and likely to continue or increase over this rate term, including at the residential stage. I am assuming you are aware, even though they're not aggregated per se, and feed into your demand forecast?

MS. MARZOUGHI: Yes.

MR. BROPHY: Yes, okay. So does that mean that if There is current DERs in place, or more that occur over this rate term that customers are implementing, they wouldn't actually be leveraged for your system planning and peak load reductions, then?

MS. MARZOUGHI: So, if we go to the evidence and we look at our non-wires program, which I am sure you have looked at and are familiar with at this point, it's in exhibit 2B, section E7.2. You will note that we are targeting 30 megawatts of non-wires capacity, and that, that 30 megawatts is targeted across our service territory at six different stations.

And to the extent that any capacity materializes and is available and can be aggregated to provide capacity and value in those areas, then we would be happy to leverage

that capacity. And those procurements that we intend to do would be open competitive procurements.

So parties who are able to aggregate capacity and offer it into our procurements at a competitive price, we would be happy to leverage that capacity.

MR. BROPHY: So, under your plan, that would be limited to the area under the 30-megawatt budget you talked about?

MS. MARZOUGHI: Yes, in the next rate period, that's the -- the use case is defined as bus-level load transfers, and that's what rolls up into that 30-megawatt target.

MR. BROPHY: Okay. What portion of your customers would fall within the area that that 30-megawatt program is being run?

MS. MARZOUGHI: So are you asking about all the customers that would be fed from those six stations and what proportion that would represent of all the customers in our system?

MR. BROPHY: Yes.

MS. MARZOUGHI: I don't know that number off the top of my head, so I would have to undertake to provide that.

MR. BROPHY: Sure, that would be great.

MR. MURRAY: That will be undertaking JT1.22.

UNDERTAKING JT1.22: TO ADVISE THE NUMBER OF CUSTOMERS THAT WOULD FALL WITHIN THE AREA OF THE 30-MW PROJECT, AND THE PROPORTION THAT NUMBER OF CUSTOMERS WOULD REPRESENT OF ALL CUSTOMERS IN THE THESL SYSTEM.

MR. BROPHY: Okay. Thank you. I think you've also

provided in your evidence that, your total number of customers, but, if you can just also include when you say "the number of customers" and then just for contrast against the total number, as well. That's -- okay, thank you.

And then does Toronto Hydro have an assessment of the DER potential in your service territory, ideally by customer segment and technology type?

MS. MARZOUGHI: By "DER potential," do you mean -- I'm not sure. Can you clarify what you mean by "DER potential"?

MR. BROPHY: Sure. Yes. So I don't know if you've been involved in industry potential studies before, but, you know, ISO and the OEB have done it for CDM, where they look at, you know, what's the potential in certain areas related to, you know, certain types of, you know, technologies and outcomes. So "potential" is, you know, if you look at what could be, if you caught everything that could be achieved in your service territory by leveraging all the DER tools and opportunities, what that would represent?

MR. HUNTLEY: Mr. Brophy, we have not done a local achievable potential study with respect to DERs.

MR. BROPHY: DERs. Okay, thank you. Okay, so a couple of questions: I think you talked about some of this this morning, but the initial question was off of Pollution Probe 5C, where you're talking about specific capacity or capabilities of the -- that Toronto Hydro will require over

the longer duration, and the energy transition are highly dependent on when, where, and how the transition itself unfolds.

And then you were talking this morning about the least-regrets approach, and I think you referred to one of Pollution Probe's IR responses to give more meat around your definition there. So I just want to be clear on the least-regrets approach because some people could consider do nothing as least regrets, but I think we would agree that Toronto Hydro is not proposing to do nothing. Is that correct?

MR. HIGGINS: That's correct.

MR. BROPHY: Okay. And then, so maybe we could just put a little meat on the bones of -- you can help me understand what we can count on under the least-regrets approach. So there are certainly no-brainer things that seem to pop out, that I think you've included. I just want to validate.

So, number one, electrification will occur over your term. I think we can agree that that one is a no-brainer and would fit under your least-regrets approach. Correct?

MR. HIGGINS: We do expect electrification to be an increasing driver of growth, and our forecasts and scenarios, which include electrification, informed our least-regrets approach, yes.

MR. BROPHY: Okay. Thank you. And EVs and related infrastructure, another no-brainer component, I think you've talked about, right?

MR. HIGGINS: Yes.

MR. BROPHY: Yes? Okay. And then would you agree that enabling customers for DERs, including maximizing CDM, demand response, and other things, energy storage, you know -- there's a bit of a list under DERs -- would also fit into the least-regrets approach?

MR. HIGGINS: Yes, Mr. Brophy, and I think as we've articulated in a couple of places, so there is a -- the initial discussion around least regrets is found in section D4 of the Distribution System Plan. And we do mention both growth and more broadly, electrification in that piece, and we note that the grid-modernization strategy is itself part of the least-regrets approach, as well. And so, if we go to section D5, which is the grid-modernization strategy -- and, just as something to reference while we're discussing here, figure -- just give me a moment -- Figure 5, which is on page 27, this is just a visual summary of what we call our grid readiness component of the grid-modernization strategy.

What this essentially includes is everything that we are planning to do with respect to not just accommodating the DERs that we see coming at this point in time but also getting the grid and our operational capabilities and our analytical capabilities ready for a higher level of DER penetration and saturation.

And so, as part of that least-regrets approach, we're not just making sort of major infrastructure investments to accommodate more DERs, but we are also investing in our

DERMs, and our monitoring and forecasting and even some more innovative initiatives that we -- you know, they're not significant dollar investments, but they are the kinds of investments that are going to give us more flexibility and capabilities in the long term, to maximize and optimize the use of DERs on our grid.

MR. BROPHY: Okay. Thank you for that. Okay, so I would like to talk a bit about 1B-PP-11, which indicates that Toronto Hydro is taking a wait-and-see approach towards some things, including electrification. You're familiar with that term that Toronto Hydro uses, wait and see?

MR. HIGGINS: Yes.

MR. BROPHY: Okay. And, given that we know electrification is already underway and that more customers are driving things like DERs, and, you know, we talked about it already, it appears that the wait-and-see approach is in conflict with the least-regrets approach. Do you understand what I mean?

MR. HIGGINS: Yes, I know. That's a reasonable question. I think, just to clarify, the wait-and-see approach in this particular context is referring to a subcomponent of the energy transition or electrification or however you want to call it, which is wide-scale building electrification. And so taking a wait-and-see approach with a particular element of growth is part of -- I think we would say it's consistent with the least-regrets approach.

There are other areas where we are being a little bit more -- "aggressive" is not the right term, but we're moving forward more readily with certain investments based on certainty, whereas, with the building electrification, which my colleagues to the right of me can talk more about, we are being a little bit more cautious because it's yet to be seen how that market segment is going to unfold.

MR. BROPHY: Okay. So the kind of overarching lens is the least-regrets approach, but then, in some more isolated circumstances, you're applying the wait-and-see approach where you think it might make sense. Does that capture it adequately?

MR. HIGGINS: Yes. I would say wait-and-see is an option amongst the choices that we could make around a least-regrets approach. So, in this case, deciding to wait and see we believe is the option that would incur the least regrets, if I can put it that way, and that's because we don't want to over build for something that may not happen on the timeline, on a more ambitious timeline.

MR. BROPHY: Okay. And if we applied wait and see to the wrong things, it could actually cause a lot of regret. So, we shouldn't just apply it without significant rigour. Is that correct?

MR. HUNTLEY: Yes, that's correct, Mr. Brophy. But the reason the decarbonization of heat was selected for the wait and see approach in this particular case, was because of two reasons. Firstly, it was recognized that, of the electrification drivers, that particular driver represented

the most significant variability in the near term, meaning this rate period, due to the policy environment that's still evolving regarding the decarbonization of heat.

But, secondly, and more importantly, the Toronto Hydro grid is a summer peaking grid, and the decarbonization of heat, in particular, was a winter concern, or it has an impact on the winter peak, which at this particular time the system offers more flexibility by having more capacity available.

So, the risk of applying a wait and see approach to the decarbonization of heat was deemed tolerable under these circumstances.

MR. BROPHY: Yes. Okay. No, I understand that, and agree. And I think it would also be true, then, if that scenario were to occur on electrification of space heating, where there's sufficient capacity given that Toronto Hydro is summer peaking, many of those modern technologies reduce summer peak for cooling, that's why IESO is promoting like cold climate air source heat pumps. So, there would even be a synergistic benefit to Toronto Hydro summer peaking grid, I think. Does that sound right?

MR. HUNTLEY: That seems reasonable, Mr. Brophy.

MR. BROPHY: Okay. Thank you. Okay. So, 1B-Pollution Probe-14 talked about best available information on energy efficiency design, and it indicated that there's best practice energy efficiency design is about three-quarters less energy use than baseline buildings. And we don't need to go into the minutia of all those numbers.

And then, in Pollution Probe-14, Toronto Hydro was asked about its efforts to promote best practice energy efficiency, and Toronto Hydro indicated that you're coordinating with the city on their plans, but that it's primarily through your affiliate, I think is what I picked up from your answer. Is that correct?

MR. HIGGINS: Just to be a little more precise, it is through our climate action program, which is a non-rate-regulated aspect of the utility.

MR. BROPHY: Okay. Yes. Okay. Perfect. So, just a question that comes out of that is: We don't want to underestimate the benefits that the affiliate or non-rate-regulated program can bring, but the core regulated utility has a responsibility to support the needs in its service territory, including DER, CDM, and a lot of things that the City of Toronto plan is pushing.

So, why underplay the importance of the regulated utility in supporting those outcomes through the plan period? I'm assuming you agree that the regulated utility has a purpose, and an obligation to enable those solutions for its customers over the term as well, is that correct?

MS. MARZOUGHI: I can try to answer that, Mr. Brophy. So, we would agree that the regulated utility has a role to play in promoting or helping our customers achieve their energy efficiency goals, and that comes through managing connections in a timely manner and helping them make -- enabling the decisions that they are making. And then, on top of that, investing in all of the things that Mr.

Higgins talked about that helps us incorporate these DERs into our system planning, helps us improve our grid observability, so that we can continue to make decisions that factor in the uptake of DERs and other types of controllable or energy efficiency resources. So, in that sense, we, I think, have demonstrated our commitment to this through our plan and our actions to date. I don't know if that answers your question.

MR. BROPHY: Sure. I think it partially does. It's just I was a little surprised it didn't highlight the opportunities and obligation of the regulated utility in doing a lot of this. And I know Toronto Hydro does promote a lot of good things, including CDM programs on behalf of IESO and others.

So, you don't see a barrier in the regulated utility playing that, kind of, critical role over the term of the plan. Correct?

MR. KEIZER: I just think you have to be careful when you talk about the regulated utility in terms of asking these witnesses, you know, what the regulator expects or whether or not the regulator would permit them to do so. I mean, they abide by the codes and their licences and to the extent there are other programs or initiatives that the OEB may undertake, but, I think, the witness has drawn a distinction between being a facilitator, which is what they are attempting to do, as opposed to driving programs, which, I think, is something that exists, maybe, outside of the regulated utility.

MR. BROPHY: Sure. No, I can appreciate that. So, Toronto Hydro has been a keen supporter of CDM programs and, in fact, I think you're clearing an LRAM against that, and also are proposing to continue to play that role in the future. I think the OEB has changed that to non-wires solutions instead of CDM guidelines now, so a little broader. So, you continue to promote those opportunities out to your customers. Correct?

MS. MARZOUGHI: Yes, that's correct.

MR. BROPHY: Okay. Thank you.

MR. MURRAY: Mr. Brophy, I see it's now 5:01. I don't know if you're one or two questions away from the end of this topic area, if this might be a good time to pause for the evening.

MR. BROPHY: This is fine. Yes.

MR. MURRAY: And just to let you know, Mr. Brophy, I think it probably makes most sense for you to complete your questioning first tomorrow, and then we'll move on to Environmental Defence beyond that.

MR. BROPHY: Well, the challenge is I do have a conflict in the morning that would probably collide with at least a portion of that. So...

MR. MURRAY: Oh, okay.

MR. BROPHY: Ideally, it would be good to have Environmental Defence go and then we would continue after. They're in logical blocks, so it's not going to --

MR. MURRAY: That's okay. I think we can accommodate that. And, Ashley, the hearings advisor will circulate a

revised or updated schedule at the end of today. I'm happy to report we're 10 minutes ahead of schedule, but given some items for panel 1 have been deferred to panel 2 or panel 3, I don't know if we're very far ahead of schedule. So, I think I would, once again, encourage people to review their questions, and if the topic's already been covered, to see if there's anything to try and adjust the questions accordingly. And with that, we'll adjourn for the day.

--- Whereupon the conference adjourned at 5:02 p.m.