Ontario

ONTARIO ENERGY BOARD

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

VOLUME: **Technical Conference**

DATE: **April 9, 2024**

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 Tuesday, April 9, 2024, commencing at 9:31 a.m.

TECHNICAL CONFERENCE

A P P E A R A N C E S

LAWREN MURRAY CHARLOTTE KANYA-FORSTNER	Board Counsel
THOMAS EMINOWICZ MARGARET DEFAZIO DANIEL ZANINI JOSH WASYLYK DANA WONG DONALD LAU ASHLEY SANASIE	Board Staff
CHARLES KEIZER DALIANA COBAN ARLEN STERNBERG	Toronto Hydro-Electric System Limited (THESL)
SHELLEY GRICE	Association of Major Power Consumers in Ontario (AMPCO)
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

Description	Page No.
NO EXHIBITS WERE FILED.	

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

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

Description	Page No.
UNDERTAKING JT2.8: TO CONFIRM WHETHER THE CONNECTION IS OCCURRING ON THE CUSTOMER PROPERTY OR AT THE POLE LEVEL, AND SPEAK IN MORE DETAIL TO WHETHER TORONTO HYDRO WOULD BE OPEN TO CONSIDERING AN ARRANGEMENT WHERE THE CUSTOMER'S ELECTRICIAN CAN DO THAT.	67
UNDERTAKING JT2.9: TO ADVISE THE TOTAL TYPICAL COST FOR ALL CONNECTION CHARGES FOR A MICRO-GEN CONNECTION, INCLUDING BASELINE, REPLACING A METER.	73
UNDERTAKING JT2.10: TO JUSTIFY THE FEES THE CONNECTION CHARGE IN TERMS OF THE ACTUAL COSTS INCURRED BY TORONTO HYDRO.	74
UNDERTAKING JT2.11: TO PROVIDE A DOCUMENT WHERE TORONTO HYDRO DEFINES A BASIC CONNECTION WITH RESPECT TO MICRO-GENERATION FACILITIES AND PROVIDE THAT EXCERPT IN THAT DOCUMENT; OR IF IT ISN'T INDICATED IN A PUBLIC FACING DOCUMENT, TO EXPLAIN WHY.	75
UNDERTAKING JT2.12: REFERENCING 2B-ED-43, TO CONFIRM IF THE FIGURES INCLUDE UPSTREAM LOSSES AND BOTH TRANSMISSION AND DISTRIBUTION LOSSES.	76
UNDERTAKING JT2.13: TO ADVISE HOW THE VALUE OF LOSSES ARE QUANTIFIED, WHETHER IT INCLUDES THE ALL-IN PRICE OF ELECTRICITY, OR JUST THE HOEP, OR OTHERWISE.	77
UNDERTAKING JT2.14: TO PROVIDE THE FIGURES BEHIND THE ALTERYX MODEL FOR EACH YEAR BETWEEN 2023-2029	84
UNDERTAKING JT2.15: REFERRING TO 2-ccMBC-6E, TO MAKE BEST EFFORTS TO INQUIRE OF STANTEC WHETHER LOW TEMPERATURE WOULD HAVE BEEN SELECTED AS A CLIMATE PARAMETER.	89

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

<u>U N D E R T A K I N G S</u>

Tuesday, April 9, 2024

--- On commencing at 9:31 a.m.

MR. MURRAY: Welcome, everyone, to day two of the Toronto Hydro technical conference. There's been a bit of a change to the schedule. Mr. Brophy, I understand you're going to be up first. But perhaps before we do that, we're having a bit of feedback, so we're going to try to deal with a technical issue.

Once again good morning, everyone. We're in day two of the technical conference for Toronto Hydro. There's been a bit of a change to the schedule. First on the schedule today will be Mr. Brophy, to complete his questioning of panel 1. Mr. Brophy, over to you.

MR. BROPHY: Great. Thank you.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED - PANEL 1, RESUMED

Rei Marzoughi

Kirk Huntley

Matthew Higgins

Githu Mundenchira

Sushma Narisetty

PRELIMINARY MATTERS:

MR. KEIZER: Sorry. Just before we begin, I have a couple of preliminary corrections, and then Mr. Brophy can begin, if that's possible.

MR. BROPHY: Yes, go ahead.

MR. MURRAY: Sorry for forgetting.

MR. KEIZER: I just know the witnesses have it on their minds, and they just want to deal with it so they can focus on Mr. Brophy. So there are a couple of corrections. I think, Ms. Narisetty, that is first with you, right?

MS. NARISETTY: Okay. The first correction I wanted to share was regarding the Toronto Green Standard. So I wanted to clarify that the Toronto Green Standard was integral to the design of the municipal energy plans, and Toronto Hydro included consideration of the municipal energy plans in its [audio dropout] forecast.

MR. KEIZER: And I think you have one additional one, I believe.

MS. NARISETTY: Yes. This was with the IR response 2B-SEC-67, regarding the question around what had changed, and I had mentioned that only the 2023 actuals had changed. But I also wanted to share that the 2024 bridge was also updated.

MR. KEIZER: And then there's one final correction, Mr. Mundenchira, you have.

MR. MUNDENCHIRA: Yes. Thank you, Mr. Keizer. There was a discussion about standard labour-rate calculations yesterday, for which I had a subject to check about confirming whether overtime is included as part of the total compensation costs. I had at the time said it is included. However, I want to make a correction that overtime is not included as part of that calculation. The references were Exhibit 2A, tab 4, schedule 2, schedule 5.1.1. Thank you.

MR. KEIZER: Thank you. That's the only preliminary matter we had.

MR. MURRAY: Thank you, Mr. Keizer. Perhaps before I go to Mr. Brophy, I'll just canvass the room to make sure there are no other preliminary matters.

MS. GIRVAN: Lawren, it's Julie Girvan here. I was the one who asked the question about the Toronto Green Standard, and I was just wondering if we could get them to file it. I didn't ask because they didn't acknowledge it yesterday.

MR. KEIZER: Sorry, just could I have a moment, Ms. Girvan?

MS. GIRVAN: Sure.

MR. KEIZER: I believe that it's a publicly available document. We're just going to confirm that it is available on the City of Toronto website, so --

MS. GIRVAN: Okay.

MR. KEIZER: -- we'll be able to advise you if you can access it there, Ms. Girvan.

MS. GIRVAN: Okay. Thank you.

MR. MURRAY: Seeing no other preliminary matters, I'm going to hand it over to Mr. Brophy.

EXAMINATION BY MR. BROPHY (CONT'D.):

MR. BROPHY: Great. Thank you. Good morning, panel. Good morning, everybody. I would like to start with 1B-Pollution Probe-11, and Appendix A. I can wait until you pull it up. It will be slide 3 of that appendix. If you need the reference again, let me know. That's the one. Perfect, thank you.

So maybe the panel can just confirm: This is the logic flow for the future energy scenarios model as outlined in the training guide for Toronto Hydro, correct?

MR. HIGGINS: Yes, this would be -- it's a high-level depiction of how the information flows from beginning to end, yes.

MR. BROPHY: Yes. Okay. Perfect, thank you. And then yesterday we were talking a bit about Toronto Hydro had indicated that it's using gross forecast as the input for your demand model and that DERs, the broader range of DERs, are not considered negative energy or a tool to reduce peak. So, when we look at the energy-flow model, the first bucket of key drivers is where everything starts and feeds in. Most of the things on that list are under the definition of DERs, so battery storage, distributor generation, EVs, energy efficiency.

So I was wondering if the panel would be able to just -- oh, I guess two things. One is it seems to be in conflict with the other modelling that doesn't include these in the forecast; and then, secondly, maybe we can just kind of walk through how these flow through the model and end up influencing Toronto Hydro's planning and forecast.

MR. HIGGINS: Sure, I can take a shot at that, Mr. Brophy. So maybe one thing I will just clarify is, for the future energy scenarios, we do have -- we are able to view both the gross and the net peak demands, so those data points are both available.

In terms of bringing this together with the load-forecasting exercise, when we set out to do the future energy scenarios, it was -- we made a deliberate decision to have it be a distinct parallel activity, the reason being that, at this stage, the goal was not to have the stations load forecast and the future energy scenarios actively converge in some way or to force them to be consistent through any kind of design iteration.

The point was to almost have a bit of a red-team/blue-team-style exercise, where we had a different team working with the consultant to develop the future energy scenarios, and then we had our capacity planning team doing the stations load forecast, and then we would sort of compare and contrast and hold the two results up against each other.

So there was no sort of deep, formal integration of the two. It was really that the future energy scenario is really meant to be a strategic product to kind of augment our intelligence and our awareness of what the future might look like.

MR. BROPHY: Okay. No, and that's helpful. I understand that the future energy model wouldn't match exactly the demand forecast, and the fact that you said it was two different teams reinforces that point.

But the general flow, I would think, would be similar, even if the specific outputs may not be exactly the same, so I guess the question is: How would you deal with that misalignment between your actual forecasting and the outcomes or outputs of the future energy model? How do you, when they tell you two different things, what do you do with that?

MR. HIGGINS: I don't know if I would agree with the characterization of it being a misalignment as such. I think it's, you know, we expect to see differences and divergences. And another thing I will just note is that the future energy scenarios tool is not really -- the power and the usefulness of the tool and the focus of the model is not really the first five years or so. We don't expect major divergence within the same time frame that would be most salient for, say, our stations load forecast. So, in that way, it's not really even meant to be held up in the very short term.

Now, in the more medium to long term, as we described in section D4 of the evidence and I think elsewhere in the interrogatories, the future energy scenarios were leveraged; we leveraged them to further enrich, essentially, the data that we could use and the scenarios that we could used to assess our least-regrets approach to expansion investments, to have a sense of when we would need certain capabilities, potentially at scale, around things like DERs.

It was just another way of having insight into how that would look long term. And we did not go through, say, an exercise to sort of directly, apples to apples, compare in a deeper way, from like a capacity planning perspective, the two items.

MR. BROPHY: Sure. Okay. Fair enough. I understand your answer. So, for the future energy model, you indicated it can run in gross mode or in net mode, where your demand forecast is just gross. So is it possible to provide the outputs of the model on a gross and a net basis? Is that a possibility?

MR. KEIZER: Sorry, Mr. Brophy, I guess I'm trying to understand to what end, given the fact that Mr. Higgins has indicated that it didn't play a role in the peak energy demand forecast, and it's a scenario, not a forecast.

MR. BROPHY: Sure.

MR. KEIZER: So, I'm not sure what the relevance is of whether it shows it as a gross or a net base.

MR. BROPHY: Okay. Well, maybe, can you just tell me if you can do that, and then I'll explain why in a second. Because if you can't do it then it doesn't make sense to even waste the time explaining why.

MR. KEIZER: It would be helpful to know why, I guess that maybe that would help the explanation as well.

MR. BROPHY: Sure. Okay. Well, let's go on that approach. So, the future energy model is used to do planning and alignment with various factors, including the list of key drivers that are there. Those key drivers are the same as what's in Toronto Hydro's evidence, but you don't actually see the impact of those key drivers in a meaningful way, because what was in the evidence is the gross demand forecast.

So, given that this model can run in gross mode and net mode, we wanted to see the difference between those two to know what the difference would be between gross and net.

MR. KEIZER: Can I just have a moment?

MR. BROPHY: Sure.

MR. KEIZER: Sorry, Mr. Brophy, the panel is just conferring, so just give me a moment.

MR. BROPHY: Sure, take whatever time you need.

MR. KEIZER: Go ahead, Mr. Higgins.

MR. HIGGINS: Yes, we should be able to provide that, I'm just going to have to check to see if it's readily available within the timeframes, but it should be possible.

MR. BROPHY: Okay, terrific.

MR. MURRAY: That will be undertaking JT2.1.

UNDERTAKING JT2.1: TO PROVIDE THE OUTPUTS OF THE MODEL ON A GROSS AND A NET BASIS

MR. BROPHY: Okay. And just to validate, like, I don't know exactly what those outputs will look like, I'm not familiar with the model. I haven't, obviously, run it. But to the extent it can provide the difference between gross and net, and indicate which of the key drivers that each element aligns to, that would be great. If that's too much for the model to handle, then just let us know.

MR. KEIZER: I guess we'll leave it, Mr. Brophy, is that we'll do what is capable of being done, I guess, within that context.

MR. BROPHY: Okay. Terrific. Thank you very much. Okay, the next question, maybe we can go to slide 4, which is actually almost the same diagram as what you had in exhibit 2B, section D4, Appendix A, figure 1. But I think it's just easiest to go to slide 4 of this document that's on the page. And the diagram that was -- I'm assuming this is probably the source of it and then it was put into your evidence, is that the X Y chart that's there, I'm assuming the panel is familiar with that figure?

MR. HIGGINS: Yes.

MR. BROPHY: Yes, okay. Great. Thank you. So, that figure shows I'll call it three scenarios, you know, left steady progression, right net zero 2040, and then in the middle a scenario that's got boxes, consumer transformation, and system transformation. From left to right, which of those represents the scenario that the Toronto Hydro rate application is meant to achieve?

MR. HIGGINS: The rate application is not based on a particular scenario.

MR. BROPHY: Okay. So, if Toronto Hydro got exactly what it asked for, you wouldn't know which of these scenarios you would be trying to achieve? Is that what you're saying?

MR. KEIZER: Well, I can what the witness -- maybe it can be explored further. But I think what the witnesses said earlier is that the future energy scenarios did not factor directly into the peak demand forecast that is referenced in the evidence, and maybe either Mr. Higgins or Mr. Huntley can clarify, you know, to the extent that it very clearly played a role. But it was, it was not, it was not geared, as I understand it, to that forecast. So, maybe the witnesses can clarify for your purposes, Mr. Brophy, especially if you have a lot of questions in this area.

MR. HIGGINS: Yes. So, I guess, going back to the response from before Mr. Brophy, the purpose of the exercise was to develop this long term view on different plausible pathways, that we may see over the longer term. Primarily to understand how rapidly under multiple different conditions external conditions we might see material changes on the distribution system and in our customer behaviour, and how much that might diverge over the longer term. And, essentially, what to watch out for and what we do need to be prepared for in the shorter term.

And so, to a certain narrow more limited extent, some of this information was used to examine whether the plans we had would be, essentially, enough to ensure flexibility if different scenarios arise, and that had implications for, on the margins, which investments we decided to pull forward and do, versus which we chose to wait and see and not do with respect to capacity. And then it also was useful context in understanding where the focus of our grid modernization strategy needed to be in the short and medium term to give ourselves flexibility, and ensure that if things do swing because of policy changes or economic changes, that we have the capabilities to adapt on the fly.

So, that's really how it was used. Not in any kind of direct way. And we certainly did not choose a particular scenario to anchor ourselves to, because that would have been counter to the purpose of the exercise.

MR. BROPHY: Okay. And I can appreciate that, particularly given the timeline of this model exceeds the 2025 and over the rate plan that you filed. So, that was one of the reasons yesterday we were talking about the longer term, you know, plan that Toronto Hydro confirmed that, you know, you've got pieces of longer term plans, but not a comprehensive one. That was a similar vein of thought around this.

So, maybe I can just simplify it then, and knowing that 2040 is beyond the term of this rate term, but are you aware of anything, any reason why the net zero 2040 scenario could not be achieved based on the plan Toronto Hydro has filed in this proceeding? Is there anything that would block that from happening? Or do you think it's aligned with that scenario?

MR. HIGGINS: So, in attempt to clarify that further, so these scenarios do go out, as you have noted, beyond 2040. The Net Zero 2040 scenario, in particular, is a very ambitious scenario. It was the one where we needed to push the model the most because some of the assumptions that are taken from Transform TO are quite aggressive in terms of technology uptake rates and, for example, really significant levels of building retrofits and things like that, that we have not seen evidence of those things happening yet.

And so the idea here behind the least-regrets model is to take things one bite at a time. And we are looking at the next five years, and the decisions we need to make to ensure that of course we don't close ourselves off to the reality that things could pick up if the political and economic and technological situations suddenly take another step-change and evolve rapidly.

But we haven't, you know, included a level of investment that would assure, necessarily, that we are on that path today. We have included a level of investment and a mix of investments that leave the door open to the possibility of meeting those demands, if and when they do occur.

MR. BROPHY: Okay. Terrific, I think that's about as close to an answer that we'll get on a topic that is as difficult as this one. Thank you, for that.

So I would like to go to 1B-Staff-46. While that's being pulled up, that's the IR response that we were referred to from Pollution Probe-20. So we'll just focus on 1B-Staff-46.

So that interrogatory asks for a comparison list of the scorecard metrics between what you currently have and what's proposed under the scorecard metrics. And there's a table describing some details of the metrics, but the comparison wasn't done.

And I understand from the response that although some of the metrics are similar, none of them are exactly the same as what the current metrics are; something, you know, has changed in every one to some extent. So there are no metrics today that match exactly to the scorecard metric list that is put forward. Is that a correct interpretation?

MR. HIGGINS: Subject to check, I believe it is a correct interpretation. In the notes there, there is some discussion on how the latest round of metrics for this rate application do fold in or can sort of subsume some of the concepts that were addressed by the previous metrics. So it's kind of an evolution, but I think it's fair what you said. Yes.

MR. BROPHY: Okay, great. Yes, and I understand some may be new or different, and others might be small changes, but none are exactly the same. So I just wanted to validate that. Thank you.

And also in Staff 46, Toronto Hydro indicates that:

> "The 2025 to 2029 investment plan, its performance objectives and the custom rate framework are an integrated proposal to meet the needs of Toronto Hydro's systems and customers."

I'm not sure if it's on the screen. I'm just going to ask you to confirm that that's correct.

MR. HIGGINS: Sorry, Mr. Brophy, are you asking me to confirm the statement on the screen?

MR. BROPHY: I'm just validating that the wording is the same here. That's correct. Yes. Okay.

So you see -- what I just read you, see on the screen in the IR response, correct?

MR. HIGGINS: Yes.

MR. BROPHY: Okay. Great. So, then, if these metrics in the scorecard are part of the integrated proposal, then does that mean that the results in the scorecard represent the baseline results that Toronto Hydro will need to deliver during the term in order to meet customer needs?

MR. HIGGINS: Can I ask you just to clarify, Mr. Brophy, what you mean by "baseline results"?

MR. BROPHY: Sure. So you put together scorecard metrics, and targets against that. That's all part of the integrated proposal that Toronto Hydro has put on the table. So I'm assuming what that means is that the scorecard represents part of that integrated proposal that Toronto Hydro has put forward in order to meet the system and customer needs over the term. Is that accurate?

MR. HIGGINS: If I'm understanding you correctly, yes, that's accurate. The performance incentives are part of the integrated proposal that is in front of the Board.

MR. BROPHY: Okay. What happens, then, you know, if one or more of the metrics in the scorecard are not achieved?

MR. KEIZER: I think that's probably a question for panel 3, Mr. Brophy.

MR. BROPHY: Okay. I'm happy to move it there. I thought it was more of a technical question. But I'm happy to bring that forward to panel 3.

Okay, so I just want to finish off; I've got just a couple of quick questions around useful life that was touched on yesterday. And there's a few references; one of them is 2B-Staff-131A. You probably don't need to pull it up. In that response, it indicates:

"Regardless of where the useful life values are set, the application of prudent asset management principles would dictate that a utility should always be operating a substantial percentage of assets beyond useful life. Toronto Hydro does not replace individual assets simply because the age of the asset has exceeded useful life value."

Are you familiar with that statement?

MR. HIGGINS: Yes, I am, Mr. Brophy.

MR. BROPHY: Okay. Great. So there was a bit of a discussion yesterday on useful life, and I'm still trying to get my head around its purpose and use. So it appears that the term "useful life" or the useful life of an asset is not the factor that drives the Toronto Hydro decision to replace the asset. It's other factors, and I know 2B-SEC-44 had a bunch of other factors: risk of failure, criticality, et cetera.

So am I on the right path by leaving that statement I just made?

MR. HIGGINS: Sorry, I just didn't quite hear the Last maybe five words that you said there. We have a fan going in the background, so it is just a little --

MR. BROPHY: Sorry. Sorry, about that. So what I was asking is it looks like useful life for an asset does not factor in as one of the elements that drives replacement of an asset. Is that correct?

And, actually, why don't I read -- there's another reference here that might be helpful to you before you answer. So, in Pollution Probe 27D, there was a response:

"The proposal to increase the service life of an asset," and that's based on the Concentric report, "primarily affects the useful life assumption used for the purpose of calculating depreciation."

So, in my mind, when I've gone through the responses, useful life is linked to depreciation, which I understand, but it's not the factor used to decide when the asset gets replaced. Is that correct?

MR. HIGGINS: That is correct.

MR. BROPHY: Okay. Okay, great. Thank you. And then -- so I know there was some talk yesterday about 24 or 25 percent of assets are beyond their useful lives. I wasn't sure what the purpose of that statistic was. I guess it is just to support that useful life may need to change and, therefore, change the depreciation?

Is that -- like, what was the purpose of highlighting that about a quarter of the assets are beyond useful life, if it's not used for asset replacement?

MR. HIGGINS: So if I can just maybe make a distinction which I hope is helpful: When it comes to specifically determining the volume of assets that need to be replaced in the distribution system plan, which is a multi-year plan -- it is not project based, except in certain circumstances -- also when making decisions at the project level about which assets to replace. In neither of those situations, where we're either setting the pace of investment or we are determining the actual project that's going to be done within a funded envelope, in neither of those situations is the fact that an asset has exceeded its useful life a determining factor in whether that assets is prioritized for replacement.

As you mentioned, in 2B-SEC-44, we talk about criticality and design considerations and all the things that we need to deal with within our service territory, that complicate that analysis. And, even when age is a factor, which it sometimes is when looking at, you know, large amounts of assets or assets that don't have condition, we're not looking at the useful life as a benchmark for decision-making there; we're looking at the oldest assets in the area.

With respect to the assets-past-useful-life metric, we do continue to include that in our evidence. It's -- to a certain extent, it's continuity with past evidence, and the things about the assets-past-useful-life metric that is ultimately useful at a high level to -- you know, it obviously has limitations to this which we're trying to underscore. But what's useful about it at the end to the day is, rather than looking at a histogram distribution of each asset class, we can boil the asset base down to a simple metric that allows us to say: Is the asset base getting older; is it getting younger in general, and, if so, at what rate is it changing? So that's really the extent of the purpose of that measure. I don't know if that answers your question, Mr. Brophy.

MR. BROPHY: No, that does for sure. Thank you for the answer. Those are all my questions, and I would just like to thank the panel. It has been very helpful, the answers provided. Thank you very much.

MR. KEIZER: All right. Sorry, Mr. Brophy, before you go, I just wanted to clarify one thing. We had moved you over to panel 3 when you had asked questions about what happens if you don't meet the scorecard measures. I just wanted to clarify because we didn't want you to lose an opportunity if you need it. Were your questions in that regard intended to be on an operational level or on a technical level, or was it intended as to what the implications were under the rate framework?

MR. BROPHY: Okay. I didn't think it would be fitting for panel 3 under the rate framework because it's about the metrics, and that panel may not be familiar with any of the metrics, themselves. And I didn't plan to walk the panel through every metric in the scorecard. I didn't think that that was helpful. But, like, if you were to pick, you know, one, two, three of those metrics, even the ones that relate to the expertise in this panel at a general sense -- again, I don't want to open up the scorecard and spend half an hour on it. But, you know, if you didn't hit those, does that mean you're not meeting the system and customer needs, or is it a different interpretation?

So I'm in your hands whether you think this panel can answer that, and again, not about any of the metrics that are outside of their scope. If they just want to answer within the metrics related to the panel, that's fine.

MR. KEIZER: That's fine. I think Mr. Higgins can give it a go.

MR. HIGGINS: Yes, at a high level, Mr. Brophy. I think this is articulated in the, you know, the scorecard evidence. But, just to summarize, the targets, well, the selection of the metrics and then ultimately the targets that were set for -- I mean, I'll speak narrowly, but I think this generally applies. But, speaking to sort of SAIDI, SAIFI, the grid modernization related stuff, that it would apply to this panel.

The targets that were set, they are the objectives of the plan, and they are objectives specifically in areas that are, you know, material elements, material outcomes, major sort of important themes of the plan. And most of those themes are tied to things that we engage customers on and heard that they have a particular view on and generally support the proposal.

So, you know, the performance incentive targets here are the objectives of the plan, and, if we don't meet them, then we would not have met the objectives of the plan.

MR. BROPHY: Okay. I think that's sufficient. Thank you very much.

MR. MURRAY: Thank you, Mr. Brophy. Next on the list is Mr. Elson.

EXAMINATION BY MR. ELSON:

MR. ELSON: Good morning. I don't believe I've met all of you. My name is Kent Elson, and I represent Environmental Defence. And I hope today to be done by lunch, is my goal, but we will see how things go.

I would like to start with 1B-ED-06, please, and I had some questions further to this interrogatory, which was asking about constraints on your customers to install distributed energy resources. And, in part A, you indicated that approximately 5 percent of Toronto Hydro's customers cannot install or cannot connect a DER. Does that include customers with a thermal constraint or just short-circuit constraints?

Is it all constraints or just one or the other?

MR. HUNTLEY: Good morning, Mr. Elson. Thank you for the question. That constraint specifically refers to short-circuit capacity.

MR. ELSON: Could you provide an undertaking to let us know how many and what percentage of Toronto Hydro customers are unable to connect a DER to the system due to any kind of constraints, thermal or short-circuit?

MR. HUNTLEY: Mr. Elson, we track the amount of customers that are unable to connect to the system, and the number currently stands at 27 between 2020 and 2023.

MR. ELSON: I'm sorry. You said the number was what number?

MR. HUNTLEY: Twenty-seven connections.

MR. ELSON: Got it. Those are the number of people who have asked to connect and have been turned down. That's what you are saying. Right?

MR. HUNTLEY: That's correct.

MR. ELSON: Got it. I'm looking for a different number, which is the number and percent of your customers who couldn't connect a DER to your system, you know, regardless of whether they've made a request anymore. I'm not looking for a point-in-time no answer as to connection requests but the number of customers who have the ability to connect versus who don't have the ability to connect.

MR. HUNTLEY: We can take that as an undertaking.

MR. ELSON: Thank you.

MR. MURRAY: That will be undertaking JT2.2.

UNDERTAKING JT2.2: TO PROVIDE THE NUMBER OF CUSTOMERS WHO HAVE THE ABILITY TO CONNECT A DER TO THE SYSTEM, VERSUS THOSE WHO DO NOT HAVE THE ABILITY TO CONNECT.

MR. ELSON: So, we would then also have a request, probably by way of an undertaking, to answer part B of this interrogatory, which is to estimate how many and what percent of Toronto Hydro customers will still be unable to connect a DER to the system due to capacity constraints by 2029, after the additional investments by Toronto Hydro. It doesn't have to have a precise answer. But an answer on a best-efforts basis. Can you undertake to provide that as well?

MR. HUNTLEY: Can you clarify the question again, please, Mr. Elson?

MR. ELSON: Yes, and I'll take one step back. We've just received an undertaking to let us know how many customers are unable to connect a distributed energy resource. And so, in addition to that, my question is, after you have made all the investments that you plan to make between now and 2029 on a best efforts basis, at that point how many and what percentage of customers will still be unable to connect to DER. Again, I know you can't provide that answer with perfect specificity, because there will be unknowns, you will have to make some sort of assumptions, but what I'm trying to determine is, how many are unable to connect now, and then how many will be unable to connect after you have made investments in your system so I can determine, you know, how many have been resolved in a sense.

MR. KEIZER: Sorry, can I just ask a question, just a clarification of the undertaking? When you talk about customers being connected to DERs, is your assumption that every customer will want to connect to a DER? So, in other words, if there is, you know, constraints for whatever reasons, short circuit or otherwise that you're asking us to count all of the customers in that area? Is that what you're asking for?

MR. ELSON: I'm not making assumptions. I'm asking a question. And the question is the number of people or customers, I should say, Toronto Hydro customers that are unable to connect now, and the number and percent that will be unable to connect after you've made the investments that you plan to make between now and 2029.

MR. KEIZER: And, sorry, the reason I ask that question was, and just to make sure we're all talking about the same thing, in response to A, that this represents approximately 5 percent of Toronto Hydro's system. I'm not sure what that -- whether that means 5 percent of the customers or whether that's 5 percent on a technical, you know, system-wide basis as opposed to a customer basis. I just want to make sure that we're all talking on the same level.

MR. ELSON: Got it. Talking about percentage of customers as opposed to, for example, percentage of peak demand or something like that?

MR. KEIZER: Yes, exactly. Or percentage of, you know, facilities or something, I'm not sure. So, maybe Mr. Huntley can clarify that, just so that we make sure we're able to do what Mr. Elson is asking to do.

MR. HUNTLEY: For the purposes of the undertaking, currently Toronto Hydro publishes a list of restricted feeders, and those feeders have customers associated with them. So, the assumption will be that the customers on those feeders, should they choose to connect to DER, would be unable to do so today. That would be the assumption we apply to satisfying the undertaking that you are requesting. And, of course, those customers would be a subset of the remaining population of Toronto Hydro customers. Would that be satisfactory?

MR. ELSON: That's exactly what I'm looking for and I think you've given that undertaking in A, and it would be helpful, and I think this was part of the undertaking, for the total number and as a percent of customers. I can do the math too, but you're more likely to do it accurately than I am.

So, my next follow-up question was for an estimate of the number and percent of Toronto Hydro customers that will still be unable to connect to DER by 2029.

MR. HUNTLEY: Mr. Elson, with respect to satisfying the requirements of your second question, just so we're clear, what we will be able to do is basically take the customer base that we have today in terms of the DER population, and extrapolate that against the investments that we will make according to the plan, and provide you with the impact of reduction and constraints on that population that we have today. Would that be satisfactory?

MR. ELSON: Yes, thank you, and I think the distinction there is you're not going to be accounting for customer growth, which is fine.

MR. HUNTLEY: That is correct.

MR. ELSON: Thank you.

MR. MURRAY: That will be undertaking JT2.3.

UNDERTAKING JT2.3: TO PROVIDE THE RESULT OF CALCULATION OF TAKING THE CUSTOMER BASE TODAY IN TERMS OF THE DER POPULATION, AND EXTRAPOLATE THAT AGAINST THE INVESTMENTS TO BE MADE ACCORDING TO THE PLAN, AND PROVIDE THE IMPACT OF REDUCTION AND CONSTRAINTS ON THAT POPULATION THAT WE HAVE TODAY.

MR. ELSON: That's very helpful. Thank you. On to part C of this interrogatory. We'd ask for a table showing the feeders, whether they're constrained, how many customers are attached to each, and whether the constraint is a short circuit or thermal. You referred us to a section in your evidence. I was looking at that evidence and it seems to only list feeders that have short circuit constraints. Do you also have feeders with thermal constraints, such that DERs can not attached?

MR. HUNTLEY: Not at this time.

MR. ELSON: Not at this time. Okay. So, why is that? Why would some utilities have thermal constraints, and Toronto Hydro not?

MR. HUNTLEY: There can be a couple of reasons. First of all, not all the DER capacity that's connected to the system is meant to export to the grid. A portion of it is for emergency generation. So, those will not have an impact on the thermal constraints of the grid itself. Predominantly, the penetration of DER in the Toronto Hydro grid has been in the micro range by volume of connections. So, from a thermal perspective, the penetration levels are not significant enough yet to be a thermal issue.

MR. ELSON: That's helpful. Do you anticipate reaching thermal limits between now and 2029, in terms of the DERs?

MR. HUNTLEY: At this time our forecast do not indicate that that's an issue.

MR. ELSON: Got it. And, mostly that would be exporting generation, so it would not a need a lot of solar, for instance?

MR. HUNTLEY: That's correct.

MR. ELSON: Okay. If we could turn to 2B-ED-07. And what I'm trying to get at here is whether, I guess, your in service additions but more so your going forward capital spending is sized for future electrification of buildings. I'm not necessarily saying that it needs to be or should be or shouldn't be, but it's an issue that we're trying to explore. And so, I had difficulty getting information on this through the interrogatories, and so I'm going to give it a shot through the technical conference now.

In terms of new connections, how do you know or how do you prepare for connections depending on whether they are going to be heated by gas versus electricity, at a sort of high level?

MS. NARISETTY: Thank you, Mr. Elson. So from a connections point of view, and Toronto Hydro facilitating that connection, it truly doesn't matter what's behind the meter and what's causing the customer to increase or decrease their demand. We look at the peak demand that the customer is requesting, and we enable that.

MR. ELSON: Well, let me ask you this question: Let's take a typical condo, which I assume is a lot of your new connections. Can you provide me with a high-level differentiation between the winter peak demand for one that is served by gas and one that is served by heat pumps? It doesn't need to be -- you can provide a high end or a low end, some sort of sense of the differing impacts?

And what I'm getting to is not the specific answer to that question, but a broader issue about how you are preparing for the potential electrification in relation to what you're spending over the next five years. So if you take, you know, a typical condo building, what's the difference in terms of the peak impact on your system?

MR. HUNTLEY: Mr. Elson, with respect to the distribution system plan, and the peak demand forecast that underpins that plan, we have said in our prefiled evidence that we have not specifically modelled the decarbonization of heat as an input into that particular plan.

The reason we did that is because we have been investing in the system for a number of years. And Toronto Hydro remains a summer peaking utility, and we anticipate that it will remain so for this rate period.

Recognizing the fact that the winter by its very nature, the ratings available in the winter are more than we have available in the summer. We felt that the plan is robust enough to accommodate the growth in building electrification in the near term, for this rate period.

Hence, we have not specifically modelled building electrification or taken it into account in the development of the plan.

MR. ELSON: What I'm asking about is whether you know that you're right-sizing your assets, not only for the electrification that will occur over the next five years, but the electrification that will occur over the lifetime of the assets. How do we know that?

MR. HUNTLEY: As we've outlined in Exhibit 2B, section D4, we have extensively discussed our approach -- our least-regrets approach that underpins our plan, and gives us confidence that the plan that we have put forward represents the correct balance of investments to provide long-term value for the ratepayer, while at the same time preparing the grid for electrification in the decades to come. And we support that through our prefiled evidence, as well, that underpins our grid modernization strategy in Exhibit 2, section D5.

MR. ELSON: Okay. I am going to follow up on that, because it comes up again in another interrogatory I want to ask you about. But sticking with ED 7, one of the questions that we are wanting to answer is if let's say, as a scenario, all of your new connections for the last three years of your plan were to be all electric. What would be impact be, and could you provide the electricity needed?

MR. KEIZER: I think first you would have to ask whether that's a realistic scenario, because it's a hypothetical that's not necessarily on any factual basis.

MR. ELSON: Well, if we had a long time, I would love to have the discussion about what the different scenarios might look like. And I think there's a differentiation between a realistic and a possible scenario or the most likely scenario, I'm not asking anyone to say what is the most likely scenario. What I'm trying to look at is get some sort of numbers behind the degree of readiness that you folks have.

I can take a step back. My understanding from the interrogatory responses is that there's about a 650-

megawatt spread between your summer and your winter peak. To me, that's a lot of space, and what I am trying to get a grasp of, with a little more specificity from you folks, is how much can you add to the system.

It may be that you would say look, if everybody wanted to connect with electric buildings in the last three years of our plan, we would still be well within the spread between summer and winter peak. That's the kind of information that I am looking for.

MR. HUNTLEY: Mr. Elson, firstly, Toronto Hydro has not modelled that scenario. Any hypothetical scenarios that may materialize, we have addressed that through the future energy scenarios.

The plan itself represents what we think is the most realistic and prudent approach to electrification. But should your hypothetical scenario unfold in some way, we have proposed the use of a demand-related variance account to provide flexibility for uncertainty as a result of electrification.

So incremental investments above or below the plan that may be triggered by any of the scenarios you may describe will be managed through that account, through the use of that account.

MR. ELSON: Okay. And I think implicit in that answer is that you would be able to connect the customers; you would be prepared, you could connect them. It wouldn't be a problem. You wouldn't be saying no you can't build that building, you have to wait for a year until, you know, we can take other special steps. Is that correct?

MR. HUNTLEY: The timing of the specific investment when it can be actually connected is not a specific commitment we can make at this time. It depends on the local conditions, and the capacity available at the grid at the point of that connection.

What I think is important is that Toronto Hydro will take appropriate steps to ensure that we can meet the needs of the customer that requires that connection.

The timing, though, we cannot make a commitment to the timing.

MR. ELSON: So if all new development in the last three years of your plan says we want to go electric, that's the way to go, you would be able to handle that from a feasibility perspective?

MR. HUNTLEY: Mr. Elson, the plan before the Board does not contemplate that scenario. We update our forecasts annually, and we are able to track the evolution of specific drivers with respect to electrification or connections, and we're prepared to adjust as needs arise and the plan evolves.

MR. ELSON: Okay. That's, I think, helpful. When I asked my question, I saw some members of your panel nodding, so I think the answer is: Yes, it would be feeble to connect customers in that scenario because you would adjust. Is that what you're saying?

MR. HUNTLEY: What I'm saying, Mr. Elson, is that we are committed to making connections and removing barriers to electrification.

MR. ELSON: Okay. To me, what you're saying is, "We'll try," and I see other panel members nodding their heads, which suggests a yes. Maybe I am drawing a false distinction here, but, you know, I think the answer is, if people -- you know, in that scenario, yes, you would be connecting those customers.

MR. HIGGINS: Maybe I'll try to put a fresh spin on this, Mr. Elson. As my colleague discussed, the plan that we have before the Board contemplates a certain forecast, and we've set our various access and service budgets accordingly. To the extent that that forecasts changes in a way that impacts any of those programs, whether it is long lead-time investments in stations expansion or immediate connections investment needs, we would adjust our outlooks and our profiles accordingly to accommodate.

At the end of the day, we're obligated to connect customers when they come to the system, and it's a little more nuanced than saying yes or no. It depends on the particular circumstance. In most situations, we can accommodate a customer even if there are restrictions. It may just take longer and be more expensive if we haven't built infrastructure in advance. So it's a spectrum of possibilities, and, again, if that hypothetical scenario were to materialize, we would have a different plan to address that.

MR. ELSON: Okay. Thank you. Now, I would like to go back to your comment about summer and winter peaking, and it would be very helpful for me to have some sort of quantification of how much electrification of new connections you could fit within the delta between your summer and your winter peak.

My understanding is that the delta is roughly 650 megawatts. If you were -- and this isn't a hypothetical meant to be something that's going to happen but just to get some sort of number, and, if you want to give me a different quantification, that's fine.

If you were to have all of your customer connections over the next five years be electrified heat instead of gas, can you give me a sense of what the additional winter load would be and whether you would then become winter peaking or whether you could fit it within the delta there?

I'm happy for an answer full of caveats and maybe a high or low estimate because I know you can't do that kind of thing with precision. I'm just trying to get some sense, with numbers, you know, what you can fit within that delta between summer and winter peak.

MR. HUNTLEY: Mr. Elson, could you clarify that scenario again? It was fairly broad.

MR. ELSON: You can frankly pick the scenario you want. What I'm trying to get at is your comment about feeling comfortable about the future of building electrification because you're currently a summer peaking jurisdiction versus a winter peaking jurisdiction. My understanding is that the delta between the two is about 650 megawatts, and I'm trying to get an idea of, you know, how many of your new connections could be electrified before it uses up, let's say, that delta, such that you switch to a winter peaking.

So I had proposed looking at it from the perspective of, well, what if all of your connections came in over the next five years as being electrified heating versus gas heating. But you could pick whatever scenario you want. I just want some numbers as opposed to, you know, the sort of high-level sense of things.

MR. HUNTLEY: We wouldn't be able to provide that to you, Mr. Elson. We have provided the spread between the summer and winter. At the moment, I think that stands at 341; it's not 600. We clarified that in an IR. And, in terms of the combination of technology that would make up that particular spread, we're unable to provide that at this time.

MR. ELSON: In other words, your can't predict the peak loads. I mean this is the thing that worries me, is that Toronto Hydro throughout the interrogatory responses wasn't able to say, well, how much more will the peak load be for a building that is heated by gas versus electricity, even at a high level, high/low estimate. I mean those are the kinds of numbers without which I don't see how you can be ready for different possible futures.

MR. HUNTLEY: Like we said, Mr. Elson, in response to the earlier portions of your question, with respect to the decarbonization of heat, it is a relatively new driver that still has several policy considerations in flux, that make it difficult to forecast in terms of its impact on peak demand that would be material to this plan.

In the near term, we are of the view that there is sufficient capacity on the grid to accommodate near-term growth with respect to the decarbonization of heat. Modelling that beyond this rate period is not an exercise that we have done thus far, but going forward, depending on how we see that particular driver evolve, we will adjust our plans accordingly to accommodate accelerated growth, should it be necessary.

MR. ELSON: My concern -- and I understand your answer, and I hear what you're saying, and I've heard it. My concern is about the right-sizing of assets that you put in the ground over the next five years and, you know, I guess the high-level planning that you're doing at this stage, which has to do with connections over the next five years but, you know, really a more longer term demand forecast. I understand that forecasting is difficult to do, but -- I'm going to come back to this, and I'm going to move to ED 21 and maybe try to come at it from that perspective.

And, in ED 21, what we had asked was for an analysis of full electrification of heating and transportation on the specific investments you're making over the rate term. And really what this question is getting at is: You're about to spend a lot of money, and are you going to have to replace all those assets maybe in 10 years but before the end of their natural life if we see full electrification of transportation and heating before the end of the life of the assets?

And you weren't able to provide an answer, and that's fair, I understand it's not an easy question.

And so, what I would like to ask for an undertaking is for something less than what we have in ED-21. And it may mean that we need to have a bit of back and forth as to what you can provide.

One thought that came to my mind was to specifically look at the top five capital projects over the rate term, and then the high and low, and demand scenarios involving full electrification, and whether those capital assets would be ones that can handle full electrification before the end of their natural life, and if not, you know, when you would have to prematurely retire them?

MR. HUNTLEY: With respect to your question, Mr. Elson, we're not of the view that it actually requires an undertaking for these reasons: The expansion investments that Toronto Hydro is making to underpin the current plan, they're driven, in large part, by municipal development. And we have flagged two specific areas in the current plan that are subject to municipal development. The size of the assets --

MR. ELSON: What do you mean by municipal development?

MR. HUNTLEY: Development of the Downsview area, the Port Lands area, and further out the development of the Golden Mile area in Scarborough.

MR. ELSON: And so, are you talking about city owned buildings or you are talking about -- what do you mean by that, exactly?

MR. HUNTLEY: We're talking about development secondary plans that are currently filed with the city.

MR. ELSON: Okay. Yes, thank you. Sorry to interrupt you.

MR. HUNTLEY: So, there is a high level of certainty around those developments being connected to the Toronto Hydro grid. The assets that we are targeting or the areas we're targeting for investment in the areas of stations expansion, specifically align with those areas of development.

So, from the stand -- from the point of view of where the plan sits, we are not -- we are not of the view, at this point in time, that those assets will be undersized or oversized. We have right-sized the plan to accommodate those developments.

But we've also stated throughout our evidence that the use of the demand variance account will ensure that we are flexible to respond to changes in not only those areas, but in other areas of the city that may experience accelerated development that we have not forecasted for at this point.

Secondly, we're currently in the third cycle of regional planning with the IESO that takes a 20-year view of development across the city, and those investments are right-sized for various scenarios that underpin electrification or growth in other areas.

MR. ELSON: In terms of those -- was it two or three major projects that you identified? It was Don Lands, Port Lands...

MR. HUNTLEY: With respect to the expansion investments that we have put forward?

MR. ELSON: Yes.

MR. HUNTLEY: We're particularly targeting the Downsview area.

MR. ELSON: Yes.

MR. HUNTLEY: We do have -- we have put forward an investment at Sheppard TS that addresses short circuit capacity for DERs.

MR. ELSON: Okay. Well, I mean, let's just take Downsview for an example. If all of the anticipated loads were to -- or customers, I guess I should say, were to electrify heating and transportation before the end of the life of the assets, would you need to replace those assets?

MR. KEIZER: So, are you saying that they should build the assets now in this plan to accommodate what might happen before the end of the life of the asset, is what you're saying, Mr. Elson?

MR. ELSON: I'm just asking questions at this stage.

MR. KEIZER: I understand you're asking questions, but I'm trying to attach it to the plan that is before the Board in this application and with respect to what the Board has to decide in the application.

MR. ELSON: Well, if you would like a preview, Mr. Keizer, you know, one of the reasons that's important is to determine, yes, whether the investments are right-sized right now, you know, that's an important question, and right-sized for the future, and whether there will be the likelihood of, you know, premature retirement, when that might come up, how that would affect investment decisions over the next five years.

It could also be relevant to questions around efforts that Toronto Hydro should be making upfront to ensure that, you know, customers are connecting in the most efficient way to use their assets in the most efficient way.

It also relates to questions around non-wire solutions, because non-wire solutions can defer investments such that by the time you put them in place, you will have, you know, more insight around the energy transition and the degree of demand from electrification, or maybe, you know, none of those points are ones that are made. I don't know. What I'm looking for is some sort of indication of what full electrification would mean for the capital being put in the ground today.

So, I'll ask the specific question relating to Downsview, just as an example. If you were to have full electrification of transportation and heating, would you need to prematurely retire the assets that you are putting in the ground?

MR. HUNTLEY: The answer is no.

MR. ELSON: Thank you. How do you know that?

MR. HUNTLEY: Based on the initial estimates with respect to the development of Downsview, we have been provided with peak demand estimates for a period of at least 15 to 20 years. And those estimates significantly exceed the assets that we are investing in today.

Now, the reason that we have confidence in the plan that we have put forward is because those investments are made in increments. We have made incremental investments to follow the development of the plan.

So, unless the plan gets cancelled all together, that really is the only scenario that we see could alter the trajectory of the investments we're undertaking at this point.

MR. ELSON: Okay. So, that's good to hear. And just to clarify what you're saying is that in that Downsview area, if there were to be full electrification of all transportation and heating, you would not need to be prematurely retiring the assets in that neighbourhood as a result of the electrification occurring before the end of life of the assets?

MR. HUNTLEY: That's correct. That was my answer.

MR. ELSON: Thank you. What about for, let's say, the other top four projects in your plan. Can you say the same thing?

MR. HUNTLEY: We apply a similar approach.

MR. ELSON: Now I know you apply a similar approach, and that's one of the reasons that I'm a bit confused, because you're talking about planning out 20, you know, 15 and 20 years, and that doesn't include a plan for full electrification. That's just a forecast, which is different from what I am asking about, which is whether those major capital investments can handle full electrification of the customers connected to them before the end of life of the assets?

MR. KEIZER: Sorry, while the witness is conferring, I will just clarify timing in term of the break, as well.

MR. ELSON: Yes. I've been looking at that as well.

MR. MURRAY: It was on my list to ask you after this line of questioning.

MR. ELSON: That was when I would like to take a break, but maybe continue on for -- maybe this will be the question that ends it, but -- or the answer that allows us to move on.

MR. HUNTLEY: Could you repeat the question, Mr. Elson?

MR. ELSON: Sure. With respect to let's say the top five capital projects, if the customers connected to those assets, all of them were to electrify space heating and transportation before the end of life of the assets, would you need to prematurely retire those assets before the end of their life?

MR. HUNTLEY: I think it's helpful, Mr. Elson, to clarify a few things. With respect to the planning approach that we used to underpin this plan and how we specifically address electrification, we approach it using a range of tools to guard against some of the things that you have outlined.

First of all, we make incremental investments to meet peak demand. Our plans are responsive to peak demand and our forecasts. Likewise, we augment that plan with demand response, for example, that allows us to defer investment or right-size equipment to accommodate particular demand drivers. And we continue to evolve in this space with respect to annual updates to our forecast, to understand the impact of drivers.

We augment our planning with tools like the future energy scenarios that gives us insight into the longer term view of what types of investments we can make that would permit the maximum long-term value for the ratepayers.

MR. ELSON: I'll have some follow-up questions, but I think we should take the break.

MR. MURRAY: Thank you, Mr. Elson. We'll come back at 11:15.

--- Recess taken at 10:58 a.m.

--- On resuming at 11:21 a.m.

MR. MURRAY: Mr. Elson, perhaps we can continue with the questions.

MR. ELSON: Yes. Are we on air?

MR. MURRAY: Yes, I believe we are.

MR. ELSON: Thank you. We were discussing before the break some of your strategies to avoid needing to prematurely retire assets due to electrification. One of those strategies was ensuring that you can make capacity increases in sort of an incremental way. What kind of assets don't lend themselves to that kind of incremental approach?

MR. HIGGINS: There's no particular type of asset or asset class that would not lend itself towards an incremental approach. I think generally with a design philosophy of our system, especially in a dense, congested area that we operate in, Mr. Elson, we would be designing things in such a way that there is the opportunity to incrementally expand over time.

MR. ELSON: Well, maybe as not on an asset-by-asset basis, but what are some of the scenarios in which you can't just make an incremental investment and you need to retire the old one?

MR. HIGGINS: I guess I'm just struggling again with the hypothetical nature of the question. I think both myself and my colleagues are. It is certainly feasible that an asset gets replaced before it has fully depreciated as a result of demand considerations or any number of considerations. There's no generic situation tied to electrification that, you know, I think we could generalize about. There's always that possibility that something may need to be replaced earlier because there's a capacity need. That does happen. But, you know, that's kind of the extent of it.

MR. ELSON: Well, let's go through some examples, then. One example that occurs to me is, you know, a pole-mounted transformer on the street level, if the houses connected to it are exceeding its capacity, you would have to replace it even if it is before the end of the life, or do you have other strategies?

MS. NARISETTY: In that specific example, you know, we have pole-top transformers on a residential street, perhaps, feeding a bunch of customers, and, if the transformer is new, then maybe we'll put up another transformer on an adjacent pole. So this way you have two transformers feeding a bunch of customers rather than one and retiring the first one.

MR. ELSON: What about your conductors? I assume you can add more conductors to a pole, and the situation when you can't take that incremental approach is when your structure or whatever, whether it's a pole or otherwise, can't handle more conductors. Is that right?

MS. NARISETTY: Could be a possibility. However, we'll still look for ways to maximize existing assets. So, for example, if the height of the pole is such that it cannot take more secondary conductors, we will supply a customer who is requesting a higher demand through an underground dip, which doesn't require, you know, that pole to be replaced, for example, and you just put an underground service to that new customer.

MR. ELSON: And I guess, if you're talking about, you know, a substation that's before the end of its life, if it reaches capacity and you don't have anymore space, then that's a difficult situation to remedy without replacing the existing equipment. Is that fair to say?

MR. HUNTLEY: Well, while that remains a possibility, our practices and our design philosophy would be to build out. Basically, if a substation has been fully utilized, we would seek to build a new substation.

MR. ELSON: Okay. One of the ways, possible ways, to -- well, let me ask a question before proposing something to you. Right now, are you tracking premature replacement of assets on an asset-by-asset basis?

MR. HIGGINS: For financial purposes, there's a certain level of tracking as projects get closed out, to build up whatever the claimed de-recognition expense would be for a given year, so there is some tracking done for those particular purposes.

MR. ELSON: And so would you be able to, for example, at this stage pull up a spreadsheet and say here are the assets that over the previous five year term have been replaced prematurely or before the end of life, I should say. "Premature" has a bit of a connotation to it, and I just mean before the end of its natural life.

MR. HIGGINS: Mr. Elson, we do in evidence have the de-recognition expense amounts by asset class, which we can point you to if that's helpful. In terms of the specific list of assets, that would be a little bit more of a challenge to produce. I won't get into the nitty-gritty details of the information systems, but, at a certain point, the linkage between what particular asset was replaced and the original reason for replacing it and the project and all of that sort of, as the project is completed and the assets are taken out of service, some of that information is not organized in a way that would make it easy to bundle up. So, while an asset or an account or something could probably be produced with some effort, any insight into and breakdown into why those assets were replaced at that time would be likely infeasible to do within the timelines of this proceeding.

MR. ELSON: All right. Okay, that's fine. Could you undertake to provide a table with the 10 most expensive before-end-of-life retirements, and have a column for why the asset was replaced before the end of life, and how to avoid that happening going forward, if there are ways to mitigate?

MR. HIGGINS: Sorry for the lengthy -- it's just this is a very kind of nuanced data issue, so we're just discussing what might be possible.

Just a note off the top, you know, there's a number of different reasons why assets would have de-recognition expense attached to them, why they would be replaced prematurely from a financial useful life perspective, most of which are going to be related to various drivers, like, you know, if we're converting a 4kV feeder, just for standardization reasons, there may be assets within that area that are not yet fully depreciated, but nonetheless need to be replaced for design considerations. There's also, I think, one of the biggest drivers of the de-recognition for us, subject, obviously, to looking at the details, would be the externally initiated plant relocations program, where we've got new subway lines being built and things like that, which require the relocation of lots and lots of assets. And there's, you know, those projects not at all triggered by consideration for age or condition.

So, it's not -- you know, it's not as well as, sorry, I should mention reactive, like, assets will fail before their end of useful life. So, that's a big driver as well.

So, you know, we're just discussing whether or not it might be possible to find the assets with, I think, your formulation, Mr. Elson, was the ten most expensive or costly, I guess would be from the perspective of the amount of de-recognition or would it be the cost of the asset that you're looking for?

MR. ELSON: I mean the ten largest in terms of cost, so presumably that's the price of the asset. You can interpret it in different ways if your data system has other figures. It wouldn't be -- the cost in terms of the remaining life of the asset, I guess you could do it that way. Whatever is easy from your system. I'm just trying to pick a sample set. So, the ten largest in terms of cost, whether that be the initial cost or whatever is undepreciated at that moment. And happy to have it on a best efforts basis so that we can move on and you can do what you can do.

And I just would add a caveat that the information you provided is helpful, we're not looking for assets that are retired just because they have broken before you expected them to, or assets where they've been externally motivated as you say. Moreso where you've had to replace them, you know, because you have demands on the system in terms of capacity or design reasons.

MR. KEIZER: Maybe, just in light of the fact that this is taking a lot of consideration, Mr. Elson, which is a difficult thing. I think part of it is trying to understand what data sets there are and what's not. And I think it is, by the fact if it was readily available, people would be able to indicate that it was. So maybe the best --

MR. ELSON: Maybe that's what your panel is come to the conclusion of right now.

MR. KEIZER: I don't know if they have come to conclusion.

MR. ELSON: I see some nodding.

MR. KEIZER: Let's let them come to a conclusion --

MR. HIGGINS: Yes, I don't think we're going to be able to, just given the nature of the data that we're talking about, we're going to be able to pinpoint drivers of the replacement to the exact value. It's going to be -- I don't think the links are going to be readily available to do that kind of categorization without significant manual effort, so, unfortunately, I don't think that's a feasible analysis.

MR. ELSON: So, you can't even pick a sample of, you know, five?

MR. HIGGINS: We could figure out on some basis what the five most -- you know, and, again, I'm not sure what the cost variable should be here, but we could somehow list the top five assets, but whether or not that premature replacement is related to a capacity consideration would be the kind of thing where it would take -- I mean, if you're looking for examples that are driven by capacity, I'm not sure how we would find those examples without significant effort.

MR. ELSON: Yes, that's fine. I'll move on to, you know, what's actually my main point, which is: How feasible would it be, on a going forward basis, to be tracking premature retirements due to, you know, a capacity driven premature retirement, doing that on a going forward basis? You can provide an undertaking, maybe, because...

MR. KEIZER: We're very intent on resolving the issue, Mr. Elson. But I think what we'll do is to the extent that we can provide a response, we will, and if we can't, then we will advise why we can't.

MR. ELSON: Sounds good.

MR. MURRAY: That will be undertaking JT2.4.

UNDERTAKING JT2.4: TO ADVISE THE FEASIBILITY OF TRACKING CAPACITY DRIVEN FUTURE PREMATURE RETIREMENTS, LISTING THE REASONS FOR PREMATURE REPLACEMENTS, DE-RECOGNITION EXPENSES, TO THE EXTENT THERE ARE FURTHER REASONS THAN THOSE ALREADY CITED.

MR. ELSON: And if you could, in that undertaking, list the reasons for premature replacements, what you call de-recognition expenses to the extent that there is more reasons than the ones you cited in testimony today, that would be helpful just to have a list. Thank you.

I have some more questions on that area, but I think I should move on and maybe come back to them, depending on whether we have the time.

I'm going to move to some questions further to 2B-ED-13. Specifically, you know, we asked some questions about geothermal heating, and, you know, I think based on your interrogatory response and some of your discussions with Mr. Brophy yesterday, that you would agree that geothermal heating, generally speaking, for particularly some of the new large buildings, would reduce the summer peak through more efficient air conditioning, but increase the winter peak, and by peak I just mean for that building. Is that a fair characterization, typically speaking?

MR. HUNTLEY: From what I can recall, Mr. Elson, we did not study the specific impact of that, but with respect to the type of technology, that was consistent with publicly available information on how it behaves.

MR. ELSON: And that's fine. I wasn't asking for you to conduct your own, you know, original research on the topic, but that's, you know, Toronto Hydro's understanding. So that's sufficient for my purposes.

And so to me what that would mean is if a condominium would be connecting to your system, and were to be heated from geothermal as opposed to gas, that would actually be reducing your system peak as opposed to increasing your system peak because, again, your system peak in the summer. And geothermal would mean that you have less of a summer system peak, other things -- sorry, less of a summer peak from the building's perspective. Does that make sense to you?

MR. HUNTLEY: That appears consistent with publicly available information, yes.

MR. ELSON: Do you think it would be appropriate for you to encourage buildings to take that route as a way to reduce costs and reduce your system peak?

MR. HUNTLEY: I think, Mr. Elson, it's important to communicate that Toronto Hydro will take steps to remove barriers for electrification. From a grid capacity perspective, and from the point of view of the plan, we will ensure that capacity is available to achieve those objectives.

Advocacy with respect to specific technologies is appropriately handled by our non-rate-regulated portion of the business that has been put together to communicate those specific objectives to customers. And should that particular technology offer grid benefit, or customer benefit, to the extent that it will, that particular group will manage that.

MR. ELSON: That would be managing communication. But if, you know, a customer decision is providing grid benefit, wouldn't it be appropriate for your regulated division to encourage that either financially or otherwise, because it's providing a financial benefit to all ratepayers.

MS. MARZOUGHI: Thanks for the question. So I'm sure that you've taken a look at our non-wire-solutions narrative that's in exhibit 2B, section E7.2, where we describe our current application of non-wires, where we do go out and procure capacity to meet our system needs. And we communicate that out when and where that type of non-wires approach can actually provide a system benefit.

So to the extent that, you know, these technologies can provide system benefit, we are looking at how we can leverage them.

MR. ELSON: Yeah, and you're talking about a reactive approach when you have a system need, and seeking non-wire solutions for that. And I am talking about something which is a little bit different, which is proactive when buildings are connecting to your system, and, you know, interfacing with builders at that point, either, you know, informationally or financially. Because, you know, once you build a building, it's quite difficult to make the transfer after the fact, and much -- particularly for geothermal, you really have to do that upfront.

MR. HUNTLEY: Mr. Elson, with respect to customer choices, the approach that we have put forward is early engagement with our customers to understand their needs. At this point in time, with respect to the plan that's before the Board, our early developer engagement informs our peak demand forecast.

To the extent the customer's choice may result in a particular peak demand profile, we attempt to understand, study and incorporate that in our plan. But we have not taken the position to advocate for a specific type of technology at this time.

MR. ELSON: I'm going move on a bit and ask a bit of a broader question: My understanding is that you take the load factor as an output, and not something that you try to impact. Is that fair to say? And the reason I'm asking that question is because electrification can I would say increase and improve your load factor, and whether that's something that you should be focused more on?

MS. MARZOUGHI: So our approach has been to go to market and seek solutions from customers, not necessarily ask them prematurely to install anything to address the load factor.

MR. ELSON: So demand response, basically?

MS. MARZOUGHI: Yeah.

MR. ELSON: Got it. I mean, one of the reasons that I ask this question is that I know that ratepayers will often look at more distribution spending and think, this price is going up. But, in reality, it can be displacing fossil fuels, for example, and overall being a benefit to the customer, and overall using the wires more efficiently as you're getting more megawatt-hours going through those wires, if, for example, you add a whole bunch of loads at the nighttime, like through electric vehicles, so on and so forth.

To me, that's an important piece to track, which is the benefit that customers are getting from your wires, and something that haven't seen sort of communicated thus far.

So I am wondering if you would consider tracking, you know, distribution costs on a per megawatt-hour basis, and focusing on that as, you know, one of the indicators of the value that you are providing to your customers?

MR. KEIZER: I think you are asking them for a corporate position that may not have yet been developed, and also a position you may make, ultimately, in argument. And it's not, you know, necessarily something that's related to the evidence that's before the Board in this application.

MR. ELSON: I mean, it's related in part as performance measurement, which is certainly part of this application. I would be happy to have you take it away by way of an undertaking to comment on it.

And Mr. Keizer, I would add that, frankly from my client's perspective, it would be a way for Toronto Hydro to show the value to its customers more clearly when there is electrification occurring, that customers are getting more benefit out of the existing system. As you have more megawatt-hours, you know, more energy delivered through the same wires, and that's energy that is displacing in many cases fossil fuels and so providing more benefit. I'm happy for you to take away by undertaking the question of whether you would want to track and target total distribution costs per megawatt-hour delivered.

MR. KEIZER: Can I just have a moment? So Toronto Hydro -- sorry, just one more second. All right.

So Toronto Hydro doesn't necessarily -- may or may not necessarily accept the premise of your question, but we will take away that undertaking and consider the position.

MR. ELSON: Thank you.

MR. MURRAY: That will be undertaking JT2.5.

UNDERTAKING JT2.5: TO ADVISE ON TRACKING AND TARGETING TOTAL DISTRIBUTION COSTS PER MEGAWATT-HOUR DELIVERED.

MR. ELSON: I would like to move to a bit of a more narrow question area, which may be brief, a question at 2B-ED-17, which is about smart switches. So this question is going to, you know, how to accommodate electrification in a way that will minimize distribution costs. When customers are putting in particularly, you know, electric vehicles, sometimes they will need to upgrade their panel in order to accommodate that load. The same, you know, can be said for electrified heating. And one of the solutions for that can be a smart switch, which means that you can share the panel, you know, the full panel's capacity, not upgrade your panel, and only provides as much power to the new device that's added in relation to what the other loads are doing on your panel.

I've described that poorly, but I know from the interrogatory response that you know what I'm talking about. I was just trying to get a grip on whether that would be helpful in terms of reducing overall distribution system costs, so maybe I can just start at the level of, you know, the pole-mounted transformer outside of someone's house. If you're able to avoid a panel upgrade, or multiple customers are able to avoid a panel upgrade, with a smart switch, does that contribute to a potential deferral of replacing that pole-mounted transformer, or are they sized on a different basis?

MS. NARISETTY: The energy management device, like a switch that you just described, yes, may prevent the need for a panel upgrade or other upstream upgrades to the conductor or potentially the transformer.

And, your second part of the question, if you don't mind repeating that?

MR. ELSON: I'm sorry. I think that did answer my question. So, if you don't need to upgrade your panel, then that could prevent the need for a transformer upgrade or a conductor upgrade.

But you would still be adding load to the system, and so how is it going to show up in your capital planning process? You know, when is the trigger the size of the panel as opposed to the actual, you know, coincident peak load of the customer?

MS. NARISETTY: So it's the load for the customer that they supply to us when they are either looking for a connection or an upgrade that necessitates any upstream upgrades to the distribution system.

MR. ELSON: And I'm not even talking about upgrades triggered by the connection, itself, but the cumulative upgrades, you know. Because you're going to be having potentially a lot of customers trying to electrify, and, if they do so in a way where they avoid a panel upgrade, does that make a big difference? Does that make a big difference on a neighbourhood level?

For example, let's say it is served by the feeder or the substation; do you still need to upgrade anyways, or does the avoidance of a new panel at the customer level help you reduce overall distribution system costs and by how much?

MS. NARISETTY: So, if I can take you to our response to part D of this question, where I believe we've answered this question, and starting line 23, where the customer preferences today and the adoption rates for such devices is unknown and, yes, requires further experience for us to understand the impact on the broader distribution system. In this current rate period that we are in front of the Board for, this technology is not expected to have a material impact on our distribution capacity forecast.

MR. ELSON: Well, let me ask the question in a different way. How do you size a pole-mounted transformer, and when do you decide that it's not big enough?

Is it based on the actual demand profiles of the customers connected to that pole-mounted transformer or just the size of their panels?

MS. NARISETTY: Number of customers.

MR. ELSON: The number of customers?

MS. NARISETTY: Yes.

MR. ELSON: And the size of their panels?

MS. NARISETTY: We don't track the size of panels. So We assign a representative load --

MR. ELSON: Yes.

MS. NARISETTY: -- for the different customers. You know, there is a coincident peak calculation that occurs;

we look at that neighbourhood, and, based on that, the transformer is sized.

MR. ELSON: And how many customers do you typically attach to one pole-mounted transformer?

MS. NARISETTY: It can vary depending on the neighbourhood. It can be anywhere from 10 to 30.

MR. ELSON: Okay.

MS. NARISETTY: Maybe even higher in some cases, and it also depends on the size of the transformer.

MR. ELSON: But you're not doing a coincident peak load calculation for each group of 10 to 30 customers, are you?

MS. NARISETTY: I'll have to check that.

MR. ELSON: Okay. Well, maybe I'll ask an undertaking that would include that, but I'll wait to see what we can work into it. So let's say that all of those customers -- let's say one of those customers goes from 100 amps to 200 amps; how do you know whether that requires a transformer upgrade?

MS. NARISETTY: So, once the customer deems that they want to upgrade their panel, either the customer or their representative would contact Toronto Hydro, at which point, based on the information that we have available in our systems, we will determine if the conductor size is adequate enough to accommodate that increase, and, if it is, you know, it proceeds in that manner. But, if it's not, you know, the impact of that panel size upgrade is used to -- is accommodated through starting with a service conductor upgrade or potentially even a transformer upgrade.

MR. ELSON: I know, but when do -- how do you decide whether the transformer needs to be upgraded?

MS. NARISETTY: Based on the other customers that are connected to the transformer, too.

MR. ELSON: Based on -- well, I guess we are getting back the to that question that you weren't sure what the answer was, so maybe I'll ask for an undertaking more generally, which is how you size transformers and whether that's based on individual analysis of demand for the customers on those transformers or through other means, a more detailed explanation so that we can have a deeper understanding.

MS. NARISETTY: Yes.

MR. ELSON: Can we have an undertaking number for that?

MR. MURRAY: That will be undertaking JT2.6.

UNDERTAKING JT2.6: TO DESCRIBE HOW TRANSFORMERS ARE SIZED, WHETHER THAT IS BASED ON INDIVIDUAL ANALYSIS OF DEMAND OR THROUGH OTHER MEANS.

MR. ELSON: Okay, thank you. Now, I'm afraid I'm just going to be asking the same question as we move up the system. So for, you know, the conductors that go around my neighbourhood, how do you size those? Are you sizing them based on an assessment of the historical demand of all the customers on those lines, you know, averages across the Toronto Hydro network, you know, the assumed size of our panels? How does that work? And if you're not sure, undertaking is fine for that, as well.

MR. HIGGINS: So, at the circuit and feeder level, Mr. Elson, we would be leveraging feeder based analysis of loading using our SCADA system to figure out what the historical peak demand has been on that feeder.

MR. ELSON: Got it. So, when you're sizing feeders, then it's on historical peak demand. What about the conductors?

MR. HIGGINS: That would essentially be the same. I mean, if we're getting down to sections of the feeder, we would be looking at something more analogous to what my colleague just described, which is what are the counts of customers, what are the types of customers within those counts, assuming a sort of generic average load, applying a diversity factor to come up with a realistic peak demand and then using that kind of analysis to move forward.

MR. ELSON: Got it. Now, the way that you just described that is that the closer you get to the house, the less it's based on actuals as opposed to assumed averages is that correct?

MR. HIGGINS: That's directionally correct. We do have AMI information from our existing meters that can -- is available to designers when they're at the design stage to help with that determination. However, because we're still on first generation smart meters the intervals are not necessarily granular enough to fully rely on that. So, it's a data point, but it's not necessarily something we would rely on fully.

MR. ELSON: Yes, okay. And I'm trying to figure out how important this is to know, and I'm going to ask this question: Let's say that you have, you know, a street level transformer, it has got 10 customers attached to it. You can't answer this question on a definitive basis, but I would like your commentary on how likely it is that you're going to have to replace the transformer and the conductor if all of those customers put EVs in place and electrify their heating?

MS. NARISETTY: So, Mr. Elson, if in a particular neighbourhood on a particular street, everyone decides to electrify, we will take the necessary steps, which is, you know, upgrade the conductors, maybe install new transformers to accommodate that additional load.

MR. ELSON: Got it. And so, you would anticipate that you would need a new transformer. And when I say conductors, I don't mean the service line, I mean the, you know, conductors running around the neighbourhood for lack of a technical term. You would anticipate you would need to replace the transformers and the distribution conductors?

MS. NARISETTY: It truly is dependent on the neighbourhood.

MR. ELSON: It seems to me that you might want to be looking at that in ways that, you know, if customers are replacing panels now and making those kinds of decisions now, even at a very preliminary stage, to see what you can be doing now to avoid the need to make some of those bigger, bigger kinds of additional investments.

MR. KEIZER: Is there a question there or just a position?

MR. ELSON: Yes, and I think they were about to comment on that.

MR. KEIZER: Are you asking them if that's the case? Is that what the question was?

MR. ELSON: To comment on my comment.

MR. HIGGINS: Sorry, we were just sort of discussing what the question might be, Mr. Elson, so maybe you can...

MR. ELSON: Sure. I'll ask it this way. What are you doing now to ensure that you'll minimize the amount of street level replacements of conductors and transformers in the event that you have full electrification of neighbourhoods? Or that example of 10 -- I know that's not happening today, but, you know, we want to be looking forward to the future, you know, the ten houses on the transformer are all electrifying their heating and their transportation.

MR. HIGGINS: Right. And so, maybe we can just zoom out a little bit. We did file a grid modernization strategy at section D5. Which has a couple of -- well, really all three pillars of the strategy speak in some way to this challenge that you're talking about. And so, that consists of intelligent grid strategy, which is essentially more switches, as well as importantly more visibility into the grid. Because right now I think like most utilities that neighbourhood level grid edge visibility is somewhat limited by the available technologies.

And so, for example, a big piece of that is AMI 2.0, which we expect is going to give us the benefit of much greater visibility, but also other kinds of sensors and greater number of SCADA points on the system.

The second piece is our grid readiness part of the strategy, which it deals with also kind of low voltage level forecasting and analysis, and also importantly includes our non-wire strategy, which is a factor here as well, so looking for opportunities besides expanding infrastructure at the neighbourhood level. So, we've got pilots that are sketched out in that evidence around, you know, managed -- like, demand response for EVs, for example, and different kinds of options like that that we'll be looking into.

And then the third piece of that strategy is the analytics piece which kind of ties all this together. So, we're looking at creating predictive analytics tools that are more and more granular that can be used to understand with greater sophistication a couple of things, what is the actual loading with more precision at the feeder and neighbourhood level and customer level. And that is important because the more insight we can get into specifically, you know, down to more decimal points of clarity, what that loading is, it potentially opens up head room on our system and allows us to redirect capital and solutions to other parts of the system.

So, I could go on, I'll sort of leave it there. But I think the general point is, you know, we are making investments -- we're proposing to make investments and we have been making investments that are going to improve the observability and our ability to understand what is happening at that local level, so that as the energy transition unfolds, we can minimize the cost to every extent feasible using technology.

MR. ELSON: Okay. I'm going to go back to the questions around panel sizes. I think I'm gathering from these answers that the actual sizes of customer panels is not a variable in your, you know, capacity supply deficit calculations for your feeders or for your transformers and conductors. Is that right?

MS. NARISETTY: That's correct. We don't directly use the panel sizes as an input.

MR. ELSON: Got it. And so, avoiding a panel upgrade, the only way that that would make its way into the sizing of your distribution assets is if that -- you know, I guess you could say inadvertently limits the peak demand of that customer. So, if you have a hundred amp panel, that's, like, a maximum of 24 kilowatts, I guess, and it would mean that you can't go over that level of draw, and that's how it would be reflected in your supply deficit calculations for your feeders and other equipment. Is that fair to say?

MS. NARISETTY: That's correct.

MR. ELSON: Okay. That is what I was looking for. So, I will move now to 2B-ED-18. And that was questions about, you know, panel upgrade costs and you said that there isn't a fee for panel upgrades, but there is a fee for connecting and disconnecting, right? I think it's $600.

MS. NARISETTY: That's correct, there is a fee for connecting and disconnecting.

MR. ELSON: This is probably a stupid question, but I assume you always need to do a connection and disconnection when you're replacing a panel?

MS. NARISETTY: I believe so, yes.

MR. ELSON: Toronto Hydro always has to come out. And so, what do you do? Do you send someone out to physically disconnect the wires and then send them to reconnect it again?

MS. NARISETTY: Yes, there is an isolation and a reconnect.

MR. ELSON: Got it. And where does that happen? Is that right at someone's house?

MS. NARISETTY: I don't know the exact details of that.

MR. ELSON: Got it. Why can't the customer's electrician do that?

MS. NARISETTY: Since the disconnect occurs on the Toronto Hydro-owned asset, and our authorized personnel are the only ones who are authorized to work on that equipment, Toronto Hydro needs to do the work.

MR. ELSON: Is it on the customer's property, or off the customer's property. Is it happening at the pole, or on the customer's property?

MS. NARISETTY: That specific detail, I don't know.

MR. ELSON: Okay.

MS. NARISETTY: But perhaps it can be answered by panel 2.

MR. ELSON: Okay. I'm going to maybe wrap that into an undertaking. But let me ask first for an undertaking for an analysis to justify that cost, which may just be a very simple couple of sentences: it takes, you know, an average X hours, and here's the labour cost to send somebody out, just so that we can connect the fee that's charged to the actual cost. Is that something that you could provide?

MR. KEIZER: You're just looking for the basis of the $600 fee. Is that what you are saying?

MR. ELSON: Yeah. I guess the basis could mean how you came up with it; that would be helpful, but also a justification for it. So what's the average time that it takes and what's the actual labour costs connected to it.

MR. KEIZER: Well, I think we will undertake to provide it. To the extent we can provide the details, we will. If we can't, then we will advise what details we can't provide.

MR. ELSON: Okay. Thank you.

MR. MURRAY: That will be undertaking JT2.7.

UNDERTAKING JT2.7: TO DESCRIBE THE BASIS FOR THE $600 FEE AND ITS JUSTIFICATION; THE AVERAGE TIME IT TAKES AND THE ACTUAL LABOUR COSTS CONNECTED TO IT.

MR. ELSON: Can you undertake to compare those connections costs or, I guess, panel upgrade costs, to peers, including Alectra and Ottawa hydro?

MR. KEIZER: Sorry, you're wanting us to benchmark them? Is that what you are asking us to do?

MR. ELSON: Well, I mean, that sounds onerous, so no. Just to compare it to a handful of peers. I have said including Alectra and Hydro One. And, if that's all that you can do within the required time, then that would at least give us one point.

MR. KEIZER: If I can just have a moment? Toronto Hydro is not prepared to do that. We don't want to go forward and have to actually compare on the basis that we prepare -- that Toronto Hydro prepares it, relative to what the bases that Hydro One or Alectra, and do an investigation of their various terms and services, and whether or not they are actually apples to apples. So we don't see the relevance of it at this point.

MR. ELSON: The relevance, Mr. Keizer, is that customers are in a monopoly situation. And if they want the services, there's only one utility that they get it from. And so that's a datapoint that would justify that piece.

MR. KEIZER: As long as the basis upon which the $600 is derived is a proper basis, that's the basis on which they would charge, not relative to whether someone else receives it on a different basis and a different cost basis. So the refusal still stands.

MR. ELSON: Well, I won't agree, but again, there's nothing I can do about it.

One last undertaking on this point: Could you confirm whether the connection is occurring on the customer property or at the pole level, and speak in more detail to whether Toronto Hydro would be open to considering an arrangement where the customer's electrician can do that so as to reduce the overall cost and have one person come out instead of two?

That's something that I'm sure no panel can answer off the cuff, so I would be asking for that by way of undertaking.

MR. KEIZER: Just a moment, please. That's fine, we'll do it if we can. And, if we can't, we'll otherwise articulate why we can't, but that's fine.

MR. ELSON: Thank you.

MR. MURRAY: That will be Undertaking JT2.8.

UNDERTAKING JT2.8: TO CONFIRM WHETHER THE CONNECTION IS OCCURRING ON THE CUSTOMER PROPERTY OR AT THE POLE LEVEL, AND SPEAK IN MORE DETAIL TO WHETHER TORONTO HYDRO WOULD BE OPEN TO CONSIDERING AN ARRANGEMENT WHERE THE CUSTOMER'S ELECTRICIAN CAN DO THAT.

MR. ELSON: Okay. If I could turn to 2B-ED-23? And we had asked you how much of your peak demand is from water heating, and you said that you didn't know, which really surprised me that you can't or don't have estimates of your, you know, the components that make up your peak demand. And it seems to me that it would be difficult to ensure that you are pursuing the most cost-effective DR programs if you don't know where your load is coming from.

Can you respond to that?

MR. HUNTLEY: What's the question, Mr. Elson?

MR. ELSON: I'll ask the question in a different way. What I was asking you is to comment on my statement that you can't be ensuring that you're pursuing the most cost-effective DR programs if you don't know where your demand is coming from in different uses, you know, such as water heaters or lights, or the different sort of end uses that you might be able to target.

MS. MARZOUGHI: Thanks for the question. So our demand response program, much like the rest of our investment plan, is grounded in a ground-up analysis of our system need. So it begins with the needs. So it doesn't begin with a study of where demand response may be located in our system. It begins with a ground-up assessment of what kinds of needs we have on our system, and what kinds could be addressed utilizing demand response.

So that's the starting point. And much like any other investment decision, we look at what the needs are and then we go out and try to address them using non-wire solutions. And to the extent that water heating is controllable and dispatchable and can participate in our procurements, that would be something that we would leverage.

MR. ELSON: Do you have any idea how many of your customers have electric water heaters, what percent of your customers have electric water heaters?

MS. MARZOUGHI: I do not know that information, and I don't believe that we collect that information.

MR. ELSON: I mean, Enbridge, for example, they do customer surveys to try to figure out what kind of equipment their customers have. Frankly, they ask about electric equipment as well. You don't have anything equivalent to that? So you just have no visibility into what electric equipment is driving your customers' residential demand?

MS. MARZOUGHI: Our programs right now are actually not focused on residential customers. They're focused on commercial and industrial, for the simple reason that it's much more cost effective to target those customers at this time.

In terms of our understanding of what DERs are installed in our system, we do know that. So we have that information, and that does drive our understanding of how much capacity might be available in the areas that we are targeting.

MR. ELSON: My question actually isn't -- I know I asked about demand response, but the topic isn't only about demand response and about your visibility into your own system.

Let me ask, do you think it would be worthwhile to have that information, you know, the components of your peak demand to see where opportunities are for demand response to analyze, you know, the likely impact of different customer decisions through the energy transition from a capacity basis, so on and so forth. It seems to me like it would be helpful to have that information. Do you agree?

MR. HIGGINS: Mr. Elson, I think if we review the grid modernization strategy, I think we have signalled that we do have a strong interest in improving visibility into the system, understanding our customers better. So as part of our longer term road map, that is certainly part of the journey. And I wouldn't rule out surveys being a part of that. And we also piece together information from other publicly available sources and other agencies that are able to provide us with behind-the-meter information. That's always something we're looking to do, and we may determine it's appropriate to do a survey in the future as well.

MR. ELSON: Got it. Now, your future energy scenarios or the consultant who did the work, they must have had dis aggregated assumptions on factors like that, for example, if they're looking at electrification, they must have had, you know, some way to estimate what the current penetration of electric water heating is now, versus what it would be in the future to come up with those outputs, would you agree with that?

MR. HIGGINS: I want to avoid going too far into the weeds here, it may take some time to find references and things and we can always take questions back to our consultant, if we need to get into some specific details, but I know there were a number of interrogatories where we produced the sources of information, and a detailed explanation, including within the vendors report that was provided on how ever driver was modeled. They piece together inferring from mostly available research, as well as public government, government documents, city documents, et cetera. And then use that information to craft their models, which then predicted what would happen in the future.

MR. ELSON: Okay. I know that our schedule had I think 12:23 for lunch, Mr. Murray, I'm flexible to do it now or in 7 minutes. Now wouldn't be a bad time for me?

MR. MURRAY: Okay. Why don't we go to lunch now, and we'll come back at 1:10.

MR. ELSON: Thank you.

--- Luncheon recess taken at 12:23 p.m.

--- On resuming at 1:17 p.m.

MR. MURRAY: Mr. Elson, you can continue with your questions.

MR. ELSON: Thank you, Mr. Murray. I am going to move, actually, to ED-26. And in ED-26 -- which is 2B-ED-26 -- there's some questions about micro-generation connection costs, and a reference to a deposit being needed when there's a site assessment required. How often is there a site assessment required?

MR. HUNTLEY: Almost always.

MR. ELSON: And what does that mean? Are you talking about -- you're not talking about an in-person assessment, you're talking about a desktop assessment. Right?

MR. HUNTLEY: An in-person assessment.

MR. ELSON: In-person assessment. Why do you need to go in person?

MR. HUNTLEY: Because there's a need to evaluate the site itself to determine the conditions for the connection.

MR. ELSON: And you refer to a $500 deposit. Is it a deposit or a fee?

MR. HUNTLEY: It represents a charge that the utility is permitted to collect should a site visit be required.

MR. ELSON: Got it. So, the site visit costs five hundred bucks?

MR. HUNTLEY: I believe the strict wording of the code is up to 500 bucks.

MR. ELSON: Okay. And then there's also reference in the interrogatory response to a connection charge being applied, without reference to what that is. What's the connection charge?

MR. HUNTLEY: That's a variable charge to recover the cost of the connection assets.

MR. ELSON: So, in terms of micro-generation connection requests, you're talking about the costs of installing the materials and to install a net meter typically?

MR. HUNTLEY: Yes, the labour and material associated with the meter change out, as well as preparing the offer to connect.

MR. ELSON: And so, what's the basic fee for preparing an offer to connect and doing the meter equipment and labour?

MR. HUNTLEY: There's no fee to prepare the offer to connect. It is part and parcel of the connection itself, the process. The costs that you're referring to involves primarily labour and materials with respect to the meter.

MR. ELSON: Okay. So, the connection cost, how much is the cost to purchase the meter and install it?

MR. HUNTLEY: It's a variable cost.

MR. ELSON: Typically, roughly how much is it?

MR. HUNTLEY: I do not think I have that with me.

MR. ELSON: Okay. Can you undertake to let us know what the typical cost is for all of the connection charges for a micro-gen connection, including the baseline, which would be replacing a meter?

MR. HUNTLEY: Noted, yes.

MR. ELSON: Thank you.

MR. MURRAY: That will be undertaking JT2.9.

UNDERTAKING JT2.9: TO ADVISE THE TOTAL TYPICAL COST FOR ALL CONNECTION CHARGES FOR A MICRO-GEN CONNECTION, INCLUDING BASELINE, REPLACING A METER.

MR. ELSON: And could you also undertake to justify the fees that you and the connection charge in terms of the actual costs incurred by Toronto Hydro, and compare that to Alectra and Ottawa Hydro?

MR. KEIZER: We're taking the same position as the last refusal on that regard.

MR. ELSON: For the comparison?

MR. KEIZER: Yes.

MR. ELSON: Okay. Are you taking the same position as a willingness to provide the justification for the Toronto Hydro charges?

MR. KEIZER: No. We'll explain those.

MR. ELSON: Thank you. So, I think that would be another undertaking.

MR. MURRAY: That will be undertaking JT2.10.

UNDERTAKING JT2.10: TO JUSTIFY THE FEES THE CONNECTION CHARGE IN TERMS OF THE ACTUAL COSTS INCURRED BY TORONTO HYDRO.

MR. ELSON: Okay. Now, on page 2 of your interrogatory response, we asked you to let us know, you know, where you get the source of the authority to charge these pieces. And this is the Distribution System Code, it says a distributor shall define a basic connection and recover the cost of the basic connection through a charge to the customer. And that will include at a minimum supply and installation of any new or modified metering.

I couldn't find anywhere, well I mean, in this interrogatory response, where you actually indicated what the basic connection is and the cost of a basic connection. You don't, do you? It's not in your conditions of service for micro-generation?

MR. HUNTLEY: For clarity, could you repeat the question, please, Mr. Elson?

MR. ELSON: Sure, and you know what, what I'm going to do is ask for it by way of undertaking, because our time is short.

In your interrogatory response you referenced section

3.1.5A, which states that for micro-embedded generation facility customers, a distributor shall define a basic connection, and recover the cost of the basic connection through a charge to the customer.

Could you undertake to provide the document where Toronto Hydro defines a basic connection with respect to micro-generation facilities and provide that excerpt in that document, or if it isn't indicated in a public facing document, to explain why.

MR. HIGGINS: Yes.

MR. ELSON: Thank you.

MR. MURRAY: That will be undertaking JT2.11.

UNDERTAKING JT2.11: TO PROVIDE A DOCUMENT WHERE TORONTO HYDRO DEFINES A BASIC CONNECTION WITH RESPECT TO MICRO-GENERATION FACILITIES AND PROVIDE THAT EXCERPT IN THAT DOCUMENT; OR IF IT ISN'T INDICATED IN A PUBLIC FACING DOCUMENT, TO EXPLAIN WHY.

MR. ELSON: If we could turn to 2B-ED-43. Could you undertake to confirm if the figures in this table or figure, I should say, include upstream losses, including transmission losses? And the reason that I ask is I believe the Ottawa hydro -- or Hydro Ottawa figure does include upstream losses, so I'm not sure if we're comparing apples to apples here. Could you go back and confirm, including in relation to Hydro Ottawa, whether this is an apples-to-apples comparison, including only distribution losses not also distribution and transmission losses?

MR. HIGGINS: Yes, we can double check that.

MR. ELSON: Thank you.

MR. MURRAY: That will be undertaking JT2.12.

UNDERTAKING JT2.12: REFERENCING 2B-ED-43, TO CONFIRM IF THE FIGURES INCLUDE UPSTREAM LOSSES AND BOTH TRANSMISSION AND DISTRIBUTION LOSSES.

MR. ELSON: In part F to this interrogatory, Toronto Hydro indicated that no dollar figure is assigned to losses for investment planning purposes, which surprised me, because all of the other distributors who I've asked about this have quantified the value of loss reductions so that they can compare trade-offs between different equipment or different conductors. And so, I'm wondering if this is actually a correct answer. And if it is, how you would, for example, decide between two transformers where one is more expensive, but is able to achieve additional loss reductions?

MS. NARISETTY: Mr. Elson, I can confirm that we do take into account losses when evaluating equipment for purchase and procurement.

MR. ELSON: You take them into account on a qualitative basis? Or do you also calculate the value of the losses and factor that in on a quantitative basis as to which transformer has overall lifetime losses that are less?

MS. NARISETTY: We do quantitative.

MR. ELSON: When you say quantitative, do you mean you measure how much the difference is in terms of losses and then make a judgment call? Or do you actually do that monetary comparison that I was describing?

MS. NARISETTY: We do a monetary comparison.

MR. ELSON: You do a monetary. Okay. Well, then, I am going to ask you another question, which is can you undertake to let us know how you quantify the value of those losses and whether you include the all-in price of electricity, or just the HOEP, or otherwise? Can you undertake to provide that answer?

MS. NARISETTY: Yes.

MR. ELSON: Thank you.

MR. MURRAY: That will be Undertaking JT2.13.

UNDERTAKING JT2.13: TO ADVISE HOW THE VALUE OF LOSSES ARE QUANTIFIED, WHETHER IT INCLUDES THE ALL-IN PRICE OF ELECTRICITY, OR JUST THE HOEP, OR OTHERWISE.

MR. ELSON: Okay. So you assign a dollar value to losses when you are comparing different transformers. What about when you are deciding which conductors to put in when you're either replacing a conductor or putting a new one in for a new customer?

MR. HIGGINS: Talking about the planning stage, so we would be drawing on the different standard conductor types and sizes that we have available to us through our standards, and choosing the appropriate cable for the size of the load that needs to be carried, including the contingency capacity that needs to be carried, if it's on a trunk feeder.

So it's not a direct monetary evaluation, but we would be selecting the right cable for the job.

MR. ELSON: You would be selecting the right cable for the capacity needs, but you don't assess whether it may be cost effective to upsize the cable for the purpose of reducing distribution losses. Is that correct?

MR. HIGGINS: That's correct.

MR. ELSON: Okay. Can you undertake to consider starting that practice? You know, one of the reasons that I ask is, for example, Hydro One has started doing that analysis, and they will decide whether to upsize a conductor based on whether it would achieve overall net savings in terms of reductions of transmission losses.

And I don't want to put you on the spot today, but if you could undertake to consider that as a practice on a going-forward basis, and provide your commentary on that, whether you are willing to do that and if not, why not? That would be appreciated.

MR. HIGGINS: I think, sitting here today, I don't think we would be prepared to commit to that. I think in a number of -- well, these interrogatory responses, I guess, that we are discussing right now, and maybe some Staff ones as well, we mention that just because of our current relative performance.

But most importantly, because of the nature of our distribution system, line losses are not a significant driver of our asset decision-making portfolio -- our investment portfolios, I should say.

It is distribution-level equipment. We are in a very dense urban territory with, you know, shorter feeder runs than say utilities with -- distribution utilities, with longer runs. And it is not transmission.

Certainly the line losses issue is a significant factor on the transmission system, but it is not a significant factor, in our view, on the distribution system -- on distribution systems in general. And on our system in particular, given the characteristics of the system, it's just not something that we have invested significant engineering and planning and consulting resources into studying, for the reasons I have mentioned.

So I don't see that being a significant priority in the near-term future, so I don't think we would commit to that, sitting here today.

MR. ELSON: Doesn't shorter lines also mean that it is cheaper to upsize them?

MR. HIGGINS: There is a lot of different factors that go into the per kilometre cost of infrastructure.

MR. ELSON: I will leave that for a further part in this proceeding.

I have a question about 1B-ED-03. I am not sure if this panel can answer that or not, but I will try.

This is about Toronto Hydro's fleet of fossil fuel heating equipment. And there's reference to Toronto Hydro planning to replace it with electric equipment. Are you able to confirm whether the plan is to replace all of the fossil fuels heating equipment with electric, or just some?

And if this needs to go to another panel, just let me know.

MR. HIGGINS: Yes. I think this would be better answered by panel 2.

MR. ELSON: Panel 2? Okay. Then I will need five minutes for panel 2. But that is my only question that I will have for them.

When you are analyzing non-wires solutions, do you quantify the benefit of deferring an investment in an asset until you know more about how it will need to be appropriately sized in light of the energy transition?

MS. MARZOUGHI: So we are assessing non-wires, our non-wires program, currently, which is limited in terms of the use case that we apply these solutions towards, which is at the moment bus-level load transfers. The application of those solutions as we have stated in the evidence, we are targeting six stations. And we have a certain target based on our assessment of our ability to meet that capacity need, utilizing demand response.

And when we make those decisions, it happens on an annual basis when we assess our load transfers, which are reassessed annually. So I am not sure if that answers your question, but...

MR. ELSON: I think maybe what your answer is that because your non-wire solutions program is narrow, this is not a relevant factor? Is that what you are saying?

MS. MARZOUGHI: Let's go back to your question. Can you repeat it again, so I can be sure?

MR. ELSON: Sure. And I'll elaborate on it. You know, one of the benefits of a non-wire solution is that you can defer investment in an asset, let's say one, two, three, four, five years, and then five years out, you may find that you had less demand than you expected, so it can be smaller, or you had more demand than you expected, so you actually will make it bigger such that it will last longer.

So one of the benefits is that you defer the investment until you know more about what size it will be. It's a hard to calculate benefit, and one that's often overlooked, and I am asking whether you calculate that benefit, because it's a real benefit and an important benefit.

MS. MARZOUGHI: So again, I guess in terms of -- I would agree with your assertion that the use of non-wires enables this type of flexibility. So what you're describing, which is the ability to defer the decision to put iron in the ground, is exactly what the non-wires program gives you the ability to do.

So in terms of our approach towards quantifying that benefit, we have to start with what's the alternative. And that is what we have done in our cost-benefit analysis, which you can find in the -- I need the reference here.

MR. ELSON: You don't need the reference, for my sake.

MS. MARZOUGHI: Okay. Well, it's in exhibit 1B, tab 3, schedule 1. So it begins with that assessment of what is it that you are deferring. And so to be able to assess the value of our current program, that's what we did. We looked at what we would be deferring and what the value is. So that's where I'll leave it.

MR. ELSON: Okay. I think the answer is that you are not quantifying the option value is one way that it's described. And maybe I could ask if you could undertake to consider whether you might do so going forward in the future and how you would calculate that benefit because it's a difficult benefit to calculate and it's often excluded.

MR. KEIZER: Can I just have a moment? I think that the concern is about making a future commitment when the analysis hasn't been fully done, and I think the witness has already indicated their attempt to develop the benefit based upon the cost-benefit analysis that's associated with the non-wire solution and demand response, which she's proposed in the evidence. So I think, to that extent, we wouldn't provide the undertaking.

MR. ELSON: Well, if I'm going to save myself five minutes for panel 2, then I think I'll have to stop there. Thank you.

MR. MURRAY: Thank you very much, Mr. Elson. Mr. Ladanyi, over to you.

MR. LADANYI: Thank you, Mr. Murray. Could you tell me: I have looked at the schedule, and I see that there are two breaks this afternoon; are you still planning for two breaks?

MR. MURRAY: We are.

MR. LADANYI: All right. Thank you.

MR. MURRAY: So, in terms of the timing, maybe we will try for the first break -- maybe 10 or 15 minutes, and then we will take the first break, if that makes sense?

EXAMINATION BY MR. LADANYI:

MR. LADANYI: Very good. So my name is Tom Ladanyi, and I'm a consultant representing the Coalition of Concerned Manufacturers and Businesses of Canada, and the coalition was formed in 2016 by a group of former members of the Canadian Manufacturers & Exporters association. It has 418 members, and the president is Catherine Swift, who is a former head of the Canadian of Federation of Independent Business. You can find out more about the coalition by visiting its website, ccmbc.ca.

I was looking at and actually also watching the proceeding yesterday, and I reviewed the transcript, and I have a follow-up question on something that was discussed by Mr. Rubenstein with you yesterday. It's on pages 43 to 47 of the transcript. You don't have to turn to it. He was discussing your reliability model. I think it's called Alteryx. I keep wanting to call it "asterisk," but anyway, Alteryx model.

I was wondering if you can provide the specific output of the model for each year between 2023 and 2029, which is essentially underlying the application. I was wondering what the output looks like, SAIDI and SAIFI numbers, or whatever the output is. Some kind of a printout, I'm looking for.

MR. HIGGINS: Yes, we can provide the numbers that are behind the lines you see that were produced. Yes.

MR. LADANYI: Very good. Can we have an undertaking for that, please?

MR. MURRAY: That will be undertaking JT2.14.

UNDERTAKING JT2.14: TO PROVIDE THE FIGURES BEHIND THE ALTERYX MODEL FOR EACH YEAR BETWEEN 2023-2029

MR. LADANYI: Thank you.

MR. RUBENSTEIN: Sorry. If I could just clarify, you're talking about providing the numbers behind the line, and I think that's a little bit different than what maybe I am -- I think the undertaking was asking about the actual outputs, what comes out of the model for each of those years based on the application. And I think that you're talking about the numbers outside of the underlying projection. Are those the same things?

MR. HIGGINS: Yes, it would be -- so I guess what you see in the charts is the rolling five-year average. The model would produce the actual individual year results that go into the calculation of that five-year average. So we could give you the individual year results in the format that they come out of the model.

MR. RUBENSTEIN: And so the only thing that comes out of the model is a SAIDI and SAIFI, and annual SAIDI and SAIFI score?

MR. HIGGINS: It may be CIs and CHIs, which then need to be normalized into SAIDI, SAIFI. I can check on specifically what it is, but it will be a reliability impact, yes.

MR. RUBENSTEIN: Okay. Thank you.

MR. LADANYI: Okay. Thank you. Now, over the last couple of days, there has been a lot of discussion of DERs in this proceeding. And, when discussing DERs, are you including low-displacement DERs owned by commercial, industrial, and institutional customers?

MR. HUNTLEY: Mr. Ladanyi, can you clarify "including" those numbers and what specifically they're for?

MR. LADANYI: Well, in general discussion, for example, with Mr. Elson, and then we can go to specifics of where would you include it. Because most of the discussion over the last few days, from what I gather from the discussion with Mr. Elson and Mr. Brophy, was about roof-top solar panels on the residential buildings that are exporting into your grid. And, in fact, there are many much larger DERs that are non-exporting, that are owned by commercial, industrial, and institutional customers, that they use for load displacement under the Industrial Conservation Initiative, ICI. Are you familiar with ICI?

MR. HUNTLEY: Yes, I am.

MR. LADANYI: Now, I must say that I'm on a number of OEB committees dealing with DERs, so, in my understanding, DERs do include load displacement.

MR. HUNTLEY: Yes, that's correct.

MR. LADANYI: Very good. Many of these customers -- and I'm talking about industrial, commercial, and institutional customers -- who are eligible for ICI use, actually, gas-powered generators. Some use batteries, but a majority actually use gas-powered generators, to run essentially at peak times to reduce the peak load on your system. For that, they can avoid paying the global adjustment charge. Are you aware of that?

MR. HUNTLEY: Yes, I am.

MR. LADANYI: Thank you. Do you know how many of your customers would be taking advantage of this?

MS. MARZOUGHI: So, yes, we do collect information on which customers have opted into class A status. Panel 3 or --

MR. HUNTLEY: I think so.

MS. MARZOUGHI: Panel 3 would be best able to speak to that.

MR. LADANYI: All right. I might follow up with them if I have the time.

MS. MARZOUGHI: Okay.

MR. LADANYI: Now, when discussing DERs, the impact on your system is very different from exporting the DERs, that essentially inject excess power into your grid, and for non-exporting DERs. Is that right?

MR. HUNTLEY: From a grid-impact perspective, that would be correct.

MR. LADANYI: Very good. So there is more -- essentially, exporting DERs need to be managed more because you can suddenly get a lot of excess current injected into your grid, and then you have to do something with it, and you can't shut them off easily. Is that right?

MR. HUNTLEY: As part of our connection process, we do have anti-islanding protection on some connections. If it's a closed transition type connection that allows export into the grid, we do have methods to initiate disconnection should it be necessary.

MR. LADANYI: So the impression might have been given so far -- perhaps only in my mind; maybe with others, as well -- that the more DERs, the better; you can never have too many DERs, exporting DERs. And, in actual fact, as far as I understand, that is not the case, at all, that there are some jurisdictions -- and Hawaii is an example, South Australia, California -- where governments have tried to put restrictions on exporting DERs because there are too many of them, because they cause instability in the grid. Do you actually have an idea of what is the maximum penetration of exporting DERs that you can actually handle?

MR. HUNTLEY: At this time, we have not done a [audio dropout] at this time Toronto hydro has not conducted a local achievable potential study to determine the maximum capacity for DERs across the system.

MR. LADANYI: But it would not -- you don't think it would be 100 percent? If every customer had a DER, and every was exporting, let's say on a sunny date to your grid, you couldn't handle it, could you?

MR. HUNTLEY: There are theoretical limits to how much DER that can be.

MR. LADANYI: Very good, thank you. I'll leave it for now. Perhaps I will follow it up with another panel.

Now if you can turn to 2-CCMBC-6. And this interrogatory deals with a Stantec study, and I don't think there's anybody on the panel from Stantec, but these are general questions, and if you can't answer them, you can take undertakings. These are very simple questions. They are not trick questions in any way.

So, if you can turn to question C. And in question C I asked: Please compare and discuss probabilities of occurrences -- which is of severe weather -- predicted by the 2015 study with actual experience. And the answer was: There are only minor differences. So, the 2015 study did not predict higher incidents of severe weather, and that proved to be accurate. In the current study Stantec is also not predicting increased incidents of severe weather. Is that right?

MS. NARISETTY: Subject to check, yes.

MR. LADANYI: Thank you. So, please go to question E, which is on page 3. And it says:

"Of the climate parameters listed in table 6, none deal with low temperature. Please explain why low temperature is not listed as a climate parameter."

And your answer was that:

"The scope of 2022 study was to provide updates to the same parameters selected by AECOM in the 2015 study and not add any additional parameters. Stantec was not part of the decision-making process for the 2015 study that selected the parameters. In 2015 study only one low-temperature-related parameter was selected due to

potential for frost-heaving issues, but was
deemed to be low risk."

Why was it only frost heaving was an issue? Would not, for example, low temperatures impact your load where people are using electricity for heat pumps, let's say, and the load would be higher? So, wouldn't that be an important parameter?

MS. NARISETTY: I don't know the details of kind of what went into the parameter selection.

MR. LADANYI: Actually, I might ask you for an undertaking in a second, but let me ask a sub-question here. So, if Stantec was part of the decision-making process, would low temperature have been selected as a climate parameter, and you can ask that of Stantec. Can I have an undertaking for that?

MR. KEIZER: We'll do it on a best-efforts basis, Mr. Ladanyi.

MR. MURRAY: That will be undertaking JT2.15.

UNDERTAKING JT2.15: REFERRING TO 2-CCMBC-6E, TO MAKE BEST EFFORTS TO INQUIRE OF STANTEC WHETHER LOW TEMPERATURE WOULD HAVE BEEN SELECTED AS A CLIMATE PARAMETER.

MR. LADANYI: Now please turn to 2B-CCMBC-8. And this one also deals with severe weather events, and the risk of them. And I will not read the response, but you can read it if you like. As I understand it, the answer from Stantec was the only increased risk is an additional 1.2 days above 35 degrees C in the decade after 2015 -- 2050, so it's between 2050 and 2060 there will be only additional 1.2 days above 35 C. Is that how you understand what Stantec's report says?

MS. NARISETTY: Yes, that's what the response indicates, and, you know, the first sentence of the response, which also qualifies it by saying that the study only evaluated the material change, and the risk score for hazards, or probability scores, changed.

MR. LADANYI: So this is a question possibly for Stantec again, another undertaking or perhaps you know it. Is this -- just for the Toronto Hydro service area or is this for southern Ontario? And I was just wondering how Stantec could have identified in effect for a relatively small area of just Toronto Hydro service area. Could you ask Stantec is this only relevant to Toronto Hydro's area?

MR. KEIZER: We can do the same again on a best-efforts basis.

MR. MURRAY: That will be undertaking JT2.16.

UNDERTAKING JT2.16: TO CONFIRM WHETHER THE REGION DESCRIBED IN 2B-CCMBC-8 IS ONLY THE TORONTO HYDRO SERVICE AREA OR IS SOUTHERN ONTARIO

MR. LADANYI: So, in relation to the break, would you like to take the break now or want me to continue?

MR. MURRAY: Are you going on to a new line of questioning? If so, now probably makes sense.

MR. LADANYI: Yes. I'm actually going to a different line of questioning.

MR. MURRAY: So, why don't we take a break and we'll come back at 2:05.

MR. LADANYI: Thank you.

--- Recess taken at 1:53 p.m.

--- On resuming at 2:09 p.m.

MR. MURRAY: Mr. Ladanyi, please continue your questions.

MR. LADANYI: Thank you, Mr. Murray. Can everyone hear me? Very good. So can you turn -- please turn to 4-CCMBC-15. In question A, I asked what proportion of internal execution -- internal execution, internal execution -- and external execution is -- and planning workforce time is spent on work for capital projects?

And if you go down, you will see table 1.

MR. KEIZER: Sorry, Mr. Ladanyi, just to give you a Heads-up, this may be a question for panel 2. But maybe I will let you finish your question, but...

MR. LADANYI: Yes. I thought it might have been, but it was listed on the ones for panel 1. So give it a try. And if you can't answer me, then you can refer it to panel 2, of course.

So your text answer talks about -- it says, "Average labour transfers and capitalizations." And the title on top of table 1 is in millions, but what's given is in percentages, and not millions. And I was wondering, what is right? Which one? Is it percentages or millions? Is this a typo, or is the table indicating something different that I don't understand?

MR. MUNDENCHIRA: I believe it is a typo in the

heading, Mr. Ladanyi. It is percentages.
     MR. LADANYI: So it's percentages. Okay. Why would there be a minus for example in front of 75.7? Is that a minus sign? Or I that something else, the dash in front of the numbers?
     MR. MUNDENCHIRA: Correct. It is a minus size; it represents costs moving out of opex. So it is a credit in opex.
     MR. LADANYI: Okay. So that would mean then, the 75.7 of internal work execution costs are capitalized?
     MR. MUNDENCHIRA: Correct.
     MR. LADANYI: So what is the difference between internal work execution, and external work execution?
     MR. KEIZER: I think that's where panel 2 may come in.
     MR. MUNDENCHIRA: It might be best for panel 2, to answer your further questions on that.
     MR. LADANYI: Very good. Thank you.
     MR. KEIZER: Sorry, Mr. Ladanyi, but I think this panel can address the bottom one, which is system planning, though. Correct?
     MR. HIGGINS: Sorry...
     MR. KEIZER: That this panel 1 can address, if you had questions regarding the bottom cell relating to system planning, I believe this is something panel 1 can deal with.
     MR. LADANYI: Okay. So this panel is responsible for subsystem planning. So let me rephrase my question. Actually, I didn't mean to address system planning, but

since Mr. Keizer suggested to ask you a question: So, for example, does this mean that 68 percent of system -- 68.1 percent of system planning costs, and that would be, like -- I presume it's a department called "System planning", are capitalized?

MR. MUNDENCHIRA: Correct. Yes.

MR. LADANYI: Thank you. Now, if you can please turn to 4-CCMBC-16? And this interrogatory deals with the grid modernization strategy. And I am sorry I did not pose the questions correctly, but I think I may thank you for attempting to answer them, anyway.

I am particularly interested to know why is Toronto Hydro's grid modernization strategy so labour intensive? You're increasing staff in this area by 39 percent, from 85 to 118. I presume that's FTEs, is it?

MR. HIGGINS: Mr. Ladanyi, my understanding of this interrogatory based on the preamble is that it's with reference to staffing in the control centre.

MR. LADANYI: Control centre, all right.

MR. HIGGINS: Yeah, which would be -- we have a witness on panel 2 who can speak to the control operations.

MR. LADANYI: Perhaps we can deal with one part of your answer, which is on the next page. If you can turn to page 2 of the response?

If you look at the sentence starting in the second paragraph with, "In summary", the reference is discussed:

> "...increases to works volumes associated with installation and operation of more remotely

operable SCADA devices. A significant increase in Toronto Hydro's dependency on accurate and timely distribution system modelling, an increase in remotely monitored and managed datapoints and an increase in distributed energy resources and the potential for energy centre to take on a critical role in actively managing DERs and non-wire solutions to maintain grid stability and support and expanded market for distributed grid devices. All these requirements will increase workload relative to what is required to safely and efficiently operate today's grid."

My first question in relation to that, and you can attempt to answer it, is when you compare a non-wire solution to a wire solution, do you take into account that non-wire solution will have higher operation and maintenance costs?

MS. MARZOUGHI: So I think we should just clarify what this particular response is referencing in terms of non-wire solutions, versus what we talk about in our non-wire solutions program.

So in this IR, what they're talking about here is grid visibility of resources, and observability of those resources, and then to be able to potentially actively manage them as the utility sees fit as we continue to evolve on our grid modernization journey. I would see that as separate from the non-wire solutions that we procure in order to defer or avoid capital investment.

And so I don't think those two are related. So I just want to make that point, if that's helpful.

MR. LADANYI: Okay. Thank you, for that answer. And so there's a difference in a non-wire solution that involves your own assets which you have designed to operate, and a non-wire solution that might involve DERs owned by somebody else. And as I understand this answer, you have to have staff at your -- is it head office or control centre, actively managing those DERs. They cannot be managing themselves; somebody has to babysit them.

MS. MARZOUGHI: So, again, I think that what's being referenced here is speaking to having improved observability. And I can't speak to exactly what the control room would have to invest in, which is why this, those questions, would be better handled by panel 2.

But when talk about non-wires, we are actually talking about -- like, when we talk about our non-wires program in exhibit 2B, section E7.2, we are referencing resources that are not owned by Toronto Hydro, but they are still not actively managed by Toronto Hydro. We enter into contractual agreements, and the owners of those resources would still maintain the cost of operating their own resources. So we don't operate their resources. We just have arrangements with them to utilize the capacity.

MR. LADANYI: All right. So there could be some larger, let's say, DERs owned by commercial industrial customers which are self-managed by them, but there could be many small rooftop solar panels which are not particularly self-managed by anybody. The owner might be at work or somewhere else where all this -- working. So is that what you are talking about, when you are actively managing DERs? I'm trying to differentiate between what we are talking about.

MS. MARZOUGHI: Yeah, I understand. So when we enter into agreements with customers or aggregators as part of our non-wires program, we are not actively managing those assets. In this case, where we are outlining the investments made to improve the grid observability, again, it may not be an active management. It's an observability feature of the investments that are going to be made.

MR. LADANYI: And I'll take that up with panel 3, but you need more staff to do the observability, which is like eyeballs on a screen.

MS. MARZOUGHI: I think that those questions in terms of the workforce related to the control room investments would be best addressed to panel 3.

MR. LADANYI: Yes, I mean, in question C, I --

MR. KEIZER: Actually, it will be panel 2 --

MS. MARZOUGHI: Sorry, panel 2.

MR. KEIZER: -- would be the best.

MR. LADANYI: Panel 2, I was not planning to actually ask panel 2 any questions, so -- but we can discuss it at break, Mr. Keizer, whether I should actually ask panel 2 any questions.

MR. KEIZER: Well, we can discuss it, Mr. Ladanyi. I mean, I don't control your questioning. But, with respect to the control centre, that is where the individual who is in charge of dealing with the control centre is appearing.

MR. LADANYI: So I have a related question here, and perhaps again it's panel 2. Maybe I really should have some time for panel 2. With the grid-modernization strategy, does Toronto Hydro expect any reduction in staffing due to grid modernization or not?

MR. HIGGINS: So, with respect to the grid-modernization strategy, over different time horizons. In the immediate, you know, next five years in this plan, we're going to be -- I would expect us to be in more of a build-out stage with respect to grid modernization, so we are deploying technologies, we are implementing systems, we are developing new skills, and that likely -- well, that does require an investment in our workforce over that period.

In the longer term, one of the main points of the grid-modernization strategy is to improve the efficiency of certain core processes, everything from planning, engineering, operations, customer interfacing processes, through the use of analytics, automation, more efficient and automated system operations. So there is in the long run an expectation that this technology would result in savings, including potentially fewer people for certain functions in the company.

But, in the short term, we're in a more of a build-out innovation stage, and that will require incremental resources.

MR. LADANYI: So, within the time frame of this application, you are not expecting any staff reductions as a result of grid modernization?

MR. HIGGINS: Certainly not any net staff reductions, no. We would expect -- I mean, as we begin to develop some of these tools and whatnot, particularly in the planning side, you know, it may help to avoid hiring more people than is currently in the plan line that we filed. So there is the benefit of, if we can call it, avoided costs already as part of the plan.

MR. LADANYI: Thank you. Could you turn to 2B-CCMBC-4.1. I apologize for my misnumbering of my interrogatories, and I thank Toronto Hydro for their patience in dealing with me in trying to renumber them. So that's why it's 2B-CCMBC-4.4.

So, in question A, I asked: Please explain the decision-making process that Toronto Hydro uses to identify capacity constraints, particularly as they relate to large condominium developments, for example, at Yonge and Eglinton, which is around here; Yonge and St. Clair, south of here; and Bayview and Eglinton; and Mount Pleasant and Eglinton.

I don't know if you're aware, but this is just from the Internet: There are currently 11 large condominium buildings planned for Bayview and Eglinton, with 3,400 apartment units. I can name them all. Some are quite large, you know, up to 46 floors, and so on. By the way, one of them -- and I think too bad Mr. Elson isn't here --

is considering geothermal heating and is planning to build a large drilling, bring a large drilling rig to Bayview and Broadway and start testing exterior geothermal conditions. That's not a question for you specifically.

Do you know, at all, of the condominium buildings, for example, planned for Bayview and Eglinton, how many are planning to use heat pumps or geothermal? Do you know that, of the 11 condominium buildings? Some are under construction already.

MR. HUNTLEY: No, Mr. Ladanyi, not at this time.

MR. LADANYI: Let me ask you a general question. Do you have sufficient capacity at Bayview and Eglinton for these large new buildings? Would you have that? Like, is there enough spare capacity, or would you have to provide some kind of additional capacity, whatever form of heating they have?

MR. HUNTLEY: I would like to answer the question this way, by giving you some background on the planning process, to give you confidence that we have already considered elements to what you have described.

We do have an enhanced early developer engagement process with which we have a very close relationship with the city with respect to development plans and developers, themselves, with respect to their own plans. And we consider very closely elements of peak demand, demand profiles, and technologies when we prepare the peak demand forecast.

It is for that reason -- we do that level of engagement to determine if system expansion is required to accommodate those particular developments. If these developers have already approved city plans, we would have taken into account, to the extent that it influences this rate period, into our forecast.

MR. LADANYI: Thank you. So, if you identify -- and I don't ask you specifically about this location. It's just in general. If you identify the need for system expansion, as you mentioned, that you need additional capacity -- and you would I presume be building, putting in, maybe larger transformers elsewhere or conductors or whatever -- would condominium developers be charged to pay a contribution to pay for this development which is specifically required to serve them?

MS. NARISETTY: Mr. Ladanyi, I believe we have answered that question in part B of the response to the same IR.

MR. LADANYI: Yes, I see that.

MS. NARISETTY: Yes.

MR. LADANYI: So you could, you do, so you do sometimes charge developers, is that right, for the system expansion, not just for their connection cost at the street but actually for a transformer far away?

For example, Yonge and Eglinton here has got many new buildings that were built over the last 20 years. You probably must have upgraded some transformers in this area. There's no way that you could have not done something, and you probably will have to do it at Yonge and St. Clair.

I'm trying to understand: How do you apply, then -- you say you are applying section C in Appendix B of the Distribution System Code. How would you apply it? Can you explain to me just in kind of a summary way so we don't have to go line by line?

MS. NARISETTY: Yes, certainly. So, when a particular connection is deemed to require expansion to make that particular connection, we look at, of course, the peak load of that particular connection, along with the expansion-related costs. And that is evaluated using the economic evaluation model, which, yes, is in accordance with Appendix B of the Distribution System Code, and that spits out what is the amount of capital contribution that may be required for the customer to complete that expansion work.

MR. LADANYI: And you take into account, let's say, the system or the feeder that this development would be connected to and, if it needs a feeder expansion is required or a new larger transformer needs to be installed, do you calculate the revenues that you're going to get from this development?

If the revenues are insufficient -- and I think the period is 25 years in the Distribution System Code, so a present value of 25 years of revenues -- then you would ask a developer to pay a contribution. Would that be right?

MS. NARISETTY: Yes, we compare the revenues to the costs, and, based on how that all comes out to, a contribution may be required if the revenues are not offsetting the costs.

MR. LADANYI: I'm not going to ask. I asked interrogatory, and you have aggregate amount of contributions, so I'm not going to ask specifics, I'm going to trust that you're looking after the interest of rate payers, so the rate payers are not forced to the subsidize condominium developers. I trust you that you are looking after your interest.

MS. NARISETTY: Yes, and I can confirm, yes, all of this evaluation, and all of the connections and the processes are in accordance with the Distribution System Code.

MR. LADANYI: Now, I had a few questions related to the Nexant report, value of service. I understand from the responses that you were unable to contact Nexant. And has that changed at all, have you now contacted Nexant?

MR. HIGGINS: As to whether or not contact was made specifically, I don't know, but I do know that the individuals who worked on the report are no longer with the company.

MR. LADANYI: So, I'm not going to follow-up with these questions specifically or ask you for undertakings. I just want to understand what is the status of this Nexant report? Are we to essentially not put much weight to it because the situation has changed? Or are you saying -- what is your position now that the company -- the consultant has changed and this report was done many years ago?

MR. HIGGINS: Our view on it is that the study remains valid. We're confident in the values. They've been applied in a couple of different ways in the evidence, and they play a role internally within our asset management system. And, yes, we continue to stand by the study. The study was done in way that's kind of well established in the industry by folks who were experts at the time in value of service calculations and surveys, following best practices. And I think in a number of different IR responses, we've addressed our view on the study and the validity of the results.

MR. LADANYI: So, if I can ask you this, this is not from Nexant, but what are the objectives of the value of service study? And that would be in 2B-CCMBC-4.1.

MR. HIGGINS: I believe it's there in the preamble to the question, Mr. Ladanyi.

MR. LADANYI: Thank you for putting it on the screen. And if I notice at the bottom, it says impact of renewables in electric vehicles on both event and duration costs.

So, the time you actually commissioned this study, were you concerned that your renewables and electric vehicles can have an impact on events, I presume the SAIFI and SAIDI, on both event and duration costs of incidents?

MR. HIGGINS: It was a topic of interest at the time. While it was scoped in as a desired objective, I believe, subject to check, that ultimately the data -- there were limitations and ultimately pursuing that level of analysis, that granularity analysis at that time, which is not surprising, given this is a number of years ago. But...

MR. LADANYI: Are you still concerned about the impacts of electric vehicle chargers, for example, and renewable DERs on SAIDI and SAIFI? Because my understanding is this is from another interrogatory, that a level 2 charger at peak is equivalent to roughly five homes, and so therefore, many level 2 charges at a peak on a single street can actually knock out the power on the street. That would be a concern, wouldn't it?

MR. HIGGINS: So, I think you're talking about reliability now. If I can just clarify, what we're talking about here is establishing the event and duration cost, so essentially what would the customers' willingness to pay be to avoid an outage. And we expect directionally, I'm not sure about DERs exactly, that's much more complicated, but for electric vehicles, we would expect that if a customer is relying on electricity for their vehicle as opposed to a traditional ice vehicle, that they would be more sensitive to interruptions and therefore more willing to -- that's the hypothesis -- more willing to pay to avoid the interruption. So, that's kind of what we were looking to study here, but I just don't think we were able to do it given the limitations at the time.

MR. LADANYI: That's very interesting, because I represent a client who feels that the customers who cause problems should pay for them and who assign greater value to things should actually pay for it as well. So, if you have an electric vehicles charger, a level 2 charger, you should be charged a surcharge, this is what I believe. And many jurisdictions would have that. I know that Ontario doesn't, but I'm trying to explain where I'm coming from. And I think these are all my questions right now for CCMBC.

Now, if I can go on to my questions for Energy Probe, Mr. Murray?

MR. MURRAY: Please proceed.

MR. LADANYI: Thank you. So, as you know, I also represent Energy Probe, and for those that are not familiar with Energy Probe, Energy Probe is one of the oldest intervenors in these proceedings it's been involved with OEB proceedings for about 40 years. I was not involved with Energy Probe, I've only been involved with Energy Probe for the last six years. So, Energy Probe has a lot of history, I won't tell you too much about it. You can look up on their website as well.

So, if you can turn to active 2B-EP-25. Now, that question, I asked several questions regarding how Toronto Hydro plans to add capacity for customers to connect additional DERs. And you answered that Toronto Hydro uses historical data to forecast the likelihood of DER connection locations. Can you please provide more detail on precisely what types of historical data is used for that forecast? For example, do you only use data on how many DERs were connected in that neighbourhood in the past, or do you look at historical -- do you also look at historical and changing trends for demographics, income, home prices and other factors?

MR. HUNTLEY: In preparation of the DER forecast, the historical trending for the localized areas provide the major inputs into the forecast model.

MR. LADANYI: I'm trying to understand. Could you -- I'm having difficulty. So, what did you mean by that, sorry? Could you explain it further?

MR. HUNTLEY: We look at the history of connections in a particular area, we aggregate that and we model it going forward, taking into consideration any policy changes that may have driven adoption, as we forecast going forward.

MR. LADANYI: So, if I understand what you're saying, if an area, let's say, such as -- this is just an example, it's a Forest Hill, has a lot of DERs, you would then make sure that you would look for -- you would expect further expansion in Forest Hill versus an area like Parkdale, that doesn't have many DERs, you would not be doing anything there? Is that what I understand you just said?

MR. HUNTLEY: I wouldn't quite characterize it that way, Mr. Ladanyi. Toronto Hydro provides non-discriminatory access to the grid, regardless of where you live. If a need arises that requires a connection, we do what is necessary to enable that connection.

We also make proactive investments that would remove barriers to connection of DERs. So, under those circumstances, we would assess it on an as-needed basis, and make appropriate investments to enable that particular technology.

MR. LADANYI: So, has Toronto Hydro performed any analysis on where capacity for additional DERs is made available to customers, whether DER capacity is being allocated across the city in an equitable manner?

MR. HUNTLEY: Quarterly Toronto Hydro publishes a restricted feeder list that outlines areas of the city that have restrictions to connect to DERs.

MR. LADANYI: And that may or may not be equitable? That's, essentially, information for the public, and the public will then take advantage of it, if they can. If they can afford a DER, let's say.

And DER now, we are talking about members of the public. Essentially, from what I understand, we are talking about rooftop solar, and possibly batteries they might be exporting into the grid. Is that what we are talking about, now?

MR. HUNTLEY: One moment. Could you repeat your question again, Mr. Ladanyi, just for clarity?

MR. LADANYI: Yeah, this is -- I think DER is an unfortunate term because it encompasses so many different appliances, or let's say installations.

And my question specifically was the residential DERs; I was discussing DERs that would be on residences. And I guess a related question is this, that only certain residences can in fact have a DER. You have to have a roof, for example, to have a solar panel, unless you are in a building where you access to the roof, no solar panel. Let's say renters in apartment buildings cannot have DERs; maybe the owner can have a DER, but certainly the renters can't have it.

So we are really talking about single or semidetached buildings, where the single family typically, where they would be -- somebody would access to the roof. The owner would, or residents would have access to the roof. And they could also have a battery in the basement, if they can afford that. And so that's what we're talking about, when we are discussing DER in this question.

And many people in Toronto, as you know, cannot do that. They don't have access to the roof; they live in apartments, they don't have access to the basement. They can't have a DER in their apartment; the landlord wouldn't allow it, or on their balcony. So this is what we are talking about.

So perhaps equitable access is really dependent on the condition under which residents live. And I want to know how you are dealing with this, that the capacity is being allocated in an equitable manner?

MR. KEIZER: I don't understand how that's necessarily a fair question. The panel is here to talk about the plan it has put forward, not necessarily how to address the issues about housing and how the housing is implicated or impacted on DERs. That's more of an issue of policy with respect to how that gets dealt with.

The wires are where they are, and the attachments are taking place, you know, not through Toronto Hydro. So I am not sure it's really fair to say, how are you addressing the inequities associated with the actual physical structures that are across its system?

MR. LADANYI: Thank you, Mr. Keizer. Actually, in every one of these technical conferences, I look forward to objections from Mr. Keizer; he always objects to some of my questions. So my day has been made today. But I will actually deal with that, either in a hearing or in the argument.

So can you turn to interrogatory 2B-EP-26? In that question, I asked several questions regarding how Toronto Hydro addresses very short power outages of a few seconds or minutes, in view of the shift to more people working from home. In your response C, you answered that:

> "Momentary outages are not considered as interruptions for a customer working from home experiencing frequent momentary outages not captured by Toronto Hydro's outage management system. Does Toronto Hydro view this as a problem?"

MR. HIGGINS: Sorry, can I clarify one part of -- I am not sure if you are just reading the question, but did you say not captured in our outage management system?

MR. LADANYI: Yes. I think it's not captured. But if you tell me that it is captured, then please take me there and explain to me how it is captured.

MR. HIGGINS: Yes. Some of them are. It just depends on where we have the necessary SCADA. So on some of our lower voltage legacy parts of the system, we can't capture momentaries accurately. But on other parts, we can. So, partially, we can see. Yes.

MR. LADANYI: Your objective is to at some future date be able to do it for the whole city. Is that right?

MR. HIGGINS: That would be ideal. Yes.

MR. LADANYI: So I note that any loss of power, no matter how short, while on a work video call from home, for example -- like, I think people are on a video call right now -- can be very detrimental to the customer, even if Toronto Hydro does not view it as an interruption.

But you were telling me you are going to -- in the future, you intend to view these as interruptions. Is that right?

MR. HIGGINS: Maybe just to clarify, because there is maybe a semantic, A formal semantic issue here.

MR. LADANYI: Yes.

MR. HIGGINS: Interruptions is a defined term in, I guess, the reporting guidelines for reliability from the Ontario Energy Board, and as well as nationally. And it is in Canada, just stating the obvious, I guess, it is longer than a minute. Everything is counted as a sustained interruption. So a momentary, or momentary interruption, it is still an interruption, but it's just less than a minute.

MR. LADANYI: So how would a customer report such outages? Can they contact Toronto Hydro and say "I have a lot of these momentary outages, and I am trying to work from home, and this is a big problem for me."

How do they report this?

MR. HIGGINS: Yes, they can report it. The processes and feedback that we received around that may be better addressed by our customer care folks on panel 2. But we do welcome that feedback, whenever we can get it.

MR. LADANYI: Maybe you can answer, because I understand this is more like a management team here, so you guys are let's say managing the policy. So how does Toronto Hydro decide whether to investigate and fix issues causing, like, short outages?

MR. HIGGINS: Sorry, I was just conferring to come up with a concise response.

We do have a customer experience and reliability team within our division. And we take input from numerous channels, including customer complaints, but also, where possible, records of momentary interruptions. And we will look at those together with sustained interruptions and ultimately make a determination on where our resources will go in terms of follow-up investigations.

We manage most of that through, for example, our worst performing feeder program, where we would do feeder patrols and make decisions about, are we going to do additional spot tree trimming and things like that. So there's sort of a programmatic approach around it.

MR. LADANYI: In your response to part A, you mention the network management system upgrade. Can you provide specific examples of how will the network management system address the problem of very short losses of power to residential customers working from home, differently than the current system does?

MR. HIGGINS: So, the experts on panel 2 can probably give you a better, more -- discussion of the functionality and capabilities of the network management system.

I will say just generally as part of upgrades, including not just the NMS, but also the implementation of Oracle utility analytics. We are just capturing in a more automated way, better information about outages and how they are unfolding and impacting the system at a localized level.

So we do expect that we will have improved information and analytics going forward, which will inform better decision-making.

MR. LADANYI: Can we turn to 2B-EP-27. Now, in that question, I asked several questions regarding Toronto Hydro's data showing the number of outages by unknown causes, which increased up to 2022.

In your responses A and B, you answered that about two-thirds of interruptions lasting between one to five minutes are attributed to unknown causes. Now, for a person working from home, experiencing frequent short interruptions between one to five minutes, Toronto Hydro is suggesting that many of those interruptions are caused by unknown causes. Should people in that situation, where short power outages are common, accept that their power will randomly go out for unknown causes from time to time as a reality of working from home?

MR. HIGGINS: So, as I think we described in this response, Mr. Ladanyi, there are operational and technical reasons why we experience some amount of unknown outages. There's always some proportion of unknown outages that occur, and they are generally on the shorter end. That is essentially what makes them unknown, is they are somewhat self-clearing, and so we are able to restore power without much investigation, and then often we can't figure out after the fact what actually caused the outage in the first place. So they're unknown, and, just inherently, that's the nature of them.

The other thing we discussed in this interrogatory response is, because of the nature of our service territory, our relationship with Hydro One, the density of our infrastructure, the tree canopy, et cetera, the number of contractors who are working on and around our lines at any given time, not just our own contractors but other contractors doing other kinds of work, our system is often in a state of hold-off, which means essentially, if there is an interruption and the breaker opens, we would not automatically reclose that; we would hold it off. That's for safety of the public and folks working around our lines.

Now, in terms of the actual trend of unknown outages, I think, like with anything in the world of reliability, it varies from year to year, and we can't necessarily a hundred percent explain why certain things go up and down from year to year.

But we do -- we are making a number of investments across our capital and operational program which I won't go on at length here about. But our distribution system plan in general addresses causes of outages, and many of those causes of outages will be -- by making those investments, rather, we will be helping to control the number of unknown outages because those investments do deal with incipient equipment failures. We could have a piece of equipment that is on the verge of failing and is causing these kinds of short interruptions. By rebuilding overhead lines, we could be helping to mitigate future tree impacts, things like that. So we would expect the investment plan to help manage this part of our reliability metric.

MR. LADANYI: And you keep track of what's causing it? Like, in case you find out what was the cause for an interruption, you can kind of keep track of these and then use that to design a program to prevent these in the future as much as possible. Would that be right?

MR. HIGGINS: So, if there are a lot of unknown outages on a feeder, we will go and investigate the situation to try to get to the root cause of what's happening. For example, one of the new ways that we are doing that now is cable testing. So we will go and test cables, a section on -- sorry, sections of cable on poor-performing feeders to figure out: Is there something going on that we can't see that is causing these issues? So that is just an example. Sorry, I don't know if I answered your question.

MR. LADANYI: Yes, I think you're doing good.

MR. HIGGINS: Okay.

MR. LADANYI: You don't have to say anything more. Now, I live in an older part of city, where there are overhead conductors, and I think it was last year or perhaps the year before there was -- suddenly, the power went out, and, within a short time, there was a crew from, I think, your contractor to power line out. I went and asked them what happened, and they said it was a squirrel that had jumped on -- I guess there's a transformer there, and essentially shorted it, and the squirrel of course did not survive. They showed me the remnants of the squirrel. And they said they have lots of examples of this happening across the city. So would that be kind of something that you would keep track of generally?

MR. HIGGINS: Yes. I guess a moment of silence for the squirrel.

MR. LADANYI: I felt sorry for the squirrel, yes.

MR. HIGGINS: I shouldn't joke.

MR. LADANYI: Well, short of putting a cage around each transformer, you can't do that to keep squirrels out.

MR. HIGGINS: Well, we do. We do put animal guards on --

MR. LADANYI: Yes.

MR. HIGGINS: -- parts of the system that don't have them, and we will go and replace animal guards if we're having issues, so it is part of how we mitigate issues, yes.

MR. LADANYI: Thank you. Can we go to interrogatory 2B-EP-28. So I think there were a number of questions earlier in the proceeding or technical conference about heat pumps. In question D, I asked Toronto Hydro:

"Does Toronto Hydro have a plan in the event that there are significantly more customers install heat pumps in a particular area than anticipated?"

You answered that:

"Toronto Hydro decided to take a wait-and-see approach to investments in new capacity for accommodating wide-scale building electrification in the mid-2030s and beyond."

Can you clarify: Does that mean that Toronto Hydro does not expect home heat pumps to be adopted on a wide scale before mid-2030s?

MR. HIGGINS: I think what we're waiting to see is evidence that that adoption trend is occurring.

MR. LADANYI: But, so far, it's not really? You have not seen evidence?

MR. HIGGINS: It's a question that we continue to study, so not at this moment, no.

MR. LADANYI: Some individuals, let's say, would expect that it will be faster, and some people think it will be slower, and you're kind of on the sidelines, watching what's happening.

MR. HIGGINS: We're watching closely. I think one of the things that the future energy scenarios showed was that, in addition to growth on the demand side from heat pumps, there is a lot of at least theoretical potential in terms of thermal efficiency through building retrofits and other kinds of efficiency which could offset some of that growth. So we're keeping our eyes on a couple of different key factors that could ultimately could swing demand over time.

MR. LADANYI: Thank you. Can you turn to interrogatory 2B-EP-29. This interrogatory deals with EV chargers, and, in question D, I asked:

> "How will Toronto Hydro ensure that it does not pick certain neighbourhoods to provide sufficient capacity for future EV charging but not other neighbourhoods?:

And you answered that:

> "Toronto Hydro is planning to enhance its ability to address highly localized impacts of EV proliferation."

At what point in time is Toronto Hydro expecting the majority of single-family homes in its service area to have at least one EV charger, if ever?

MR. HIGGINS: I don't think we've looked at the question in quite exactly that way, Mr. Ladanyi.

MR. LADANYI: Okay. Can you answer it in the way you looked at it? I mean, you provided a written answer, but you are not -- are you expecting in some ways that, at some time in the future, every home will have an EV charger, or are you not? That's what I would like to know because I'm actually not, but let's see what you're expecting.

MR. HIGGINS: Sorry, just a moment. It's not a scenario the timing of which and likelihood of which we've considered, Mr. Ladanyi.

MR. LADANYI: So, in some neighbourhoods, there will be early adopters. Maybe they will all congregate in one area -- I don't know -- the annex, let's say, or who knows where or somewhere in North York, and they will have EV chargers. Some other place, somewhere in Scarborough maybe, there will be no EV chargers. So you really don't know how this is going to go, do you?

MR. HIGGINS: It might be better for my colleague to speak to this.

MR. HUNTLEY: With respect to the distribution of charging infrastructure or DERs for that matter within the service territory, there is expectation there will be variability across the territory. We have not forecasted to the granular level what that variability is, but our forecast does contemplate there's variability across the service territory.

MR. LADANYI: Actually, let's say I agree with your approach, I'm not disagreeing with it, just so you don't take it the wrong way. I think it would not be right for Toronto Hydro to overbuild the system, expecting mass adoptions of EVs, EV chargers and DERs, and then have the rest of the rate payers pay for this at much higher rates, unless there is actual revenues from people who will be using DERs and EVs. And I appreciate your approach, I am not disagreeing with it.

Now, if you can please turn to 1B-EP-3. And that interrogatory deals with what you call sustainable communities. And I asked in question D:

"Do sustainable new housing communities impose additional costs on Toronto Hydro than do existing communities?"

Your answer was:

"Sustainable new housing communities do not incur additional costs, nor are they treated differently from other customers."

Actually, I was surprised by that answer. Would homes in sustainable new communities use electric heat pumps instead of gas furnaces?

MS. NARISETTY: It's a possibility.

MR. LADANYI: So, the answer is yes? That's what you expect. And would these homes use electric water heaters instead of gas water heaters?

MS. NARISETTY: Perhaps.

MR. LADANYI: So, I would say, again, likely. And would they use electric stoves instead of gas stoves?

MS. NARISETTY: Again, it's a consumer choice, so.

MR. LADANYI: So, based on your more or less agreeing with me, wouldn't these sustainable new communities have higher peak load than existing communities that are unsustainable?

MS. NARISETTY: I think that's a very simplistic statement, because there could be many reasons. A customer may have a higher load demand. Perhaps, you know, an electric vehicle charging station, or a heat pump, or, you know, more recently that we're seeing, with the policies encouraging multiplex development, so just having, you know, in the same unit of land, encouraging multiple units of homes to be built. Or even, you know, just using more efficient appliances. They all can have a role in terms of, you know, whether they increase the total demand or if they are, again, using more efficient appliances, even decrease the total demand.

MR. LADANYI: And you feel that that can completely offset the greater load because they are more electrical appliances instead of gas appliances?

MS. NARISETTY: Sorry, what would offset?

MR. LADANYI: You're essentially saying they would not use more electricity because they're using more efficient appliances would actually offset the fact that they're using electricity for all these appliances instead of gas, is that is that what you're saying?

MS. NARISETTY: It is a possibility. And, you know, and to also clarify your previous question, which was, you know, the drivers for what is contributing to the increased load or the peak demand could be various. And not necessarily just these sustainable new housing.

MR. LADANYI: But there's a possibility that these sustainable communities will need larger transformers and other equipment to deal -- to provide them with sufficient capacity, and the meter load needs?

MS. NARISETTY: If they have a higher demand for electricity, yes.

MR. LADANYI: So, Energy Probe is concerned that customers in existing communities, which is most of the customers that you have, are being forced to subsidize these new sustainable communities. And that was the subject of question E and your answer mentions cost allocation. So, how would you use cost allocation to ensure that the customers in existing communities don't end up subsidizing sustainable communities?

MR. KEIZER: I don't know if this is an appropriate question for this panel.

MR. LADANYI: Which panel should I ask?

MR. KEIZER: Well if we're talking about cost allocation, that would be panel 3.

MR. LADANYI: All right. Cost allocation, very good. I mean, I think the interrogatory response mentions cost allocation, I was wondering how that would be done, but I'm scheduled to ask panel 3 some questions, so I should be there -- I'll be there to ask these questions.

Now, if you can turn to 1B-EP-5. Now, in question A I asked you to confirm that customers who owned DERs impose additional cost on Toronto Hydro. And you confirmed that. Thank you.

I also wanted to follow-up this with a somewhat related question. I understand that building code requires that all buildings with more than six stories must have standby power supply. And most of these are gas fire generators. Would you consider these to be DERs or not?

MR. KEIZER: The first question is whether they are in a position to verify the building code that you've suggested.

MR. LADANYI: You can look it up. You know, if you want to do an undertaking to check the building code.

MR. KEIZER: Anyway, let's -- Mr. Huntley may be able to take the question, but maybe on the basis of if someone has supplementary power, emergency power in their building, is that DERs, without getting into the building code.

MR. HUNTLEY: I would say that's a yes, Mr. Ladanyi.

MR. LADANYI: Thank you. So, if we were to actually walk around this area, and be able to go inside, you would probably find out that every single one of these towers across the street and so on, has a big gas powered generator in the basement to run the elevators when their power goes out, otherwise if there's no power, there's no running water above a certain height. There's also people can't get to their apartments, the power is required all the time. So, that's what I'm talking about. And you know that, of course.

Sort of back to the interrogatory, in question B. I asked:

> "Does Toronto Hydro require new customers who are installing DERs to pay a contribution to offset the cost they impose on Toronto Hydro?"

MR. KEIZER: Sorry, Mr. Ladanyi, do you have a question there? Or?

MR. LADANYI: Yes, the question was does Toronto Hydro charge customers who own DERs who impose additional costs on Toronto Hydro, does it charge them a contribution or a charge? Or does it charge them nothing?

MR. KEIZER: And isn't the answer on the screen in response B?

MR. LADANYI: It says "it complies with the requirements of the Distribution System Code, and I'm trying to understand how is this covered in the Distribution System Code. You are free to take me to the Distribution System Code and explain how you apply the Distribution System Code to calculate whether contribution is required.

MR. KEIZER: Well, I don't think we need to go through the Distribution System Code. But I mean it is there and it's a public document, it's part of the Board's codes.

MR. LADANYI: Okay, Mr. Keizer, the Distribution System Code is a very large document, and I would like an undertaking then. Specific references to different parts of the Distribution System Code which explain how you would do that. Can we have an undertaking, please?

MR. KEIZER: That's fine. So it's basically how Toronto Hydro applies the Distribution System Code to calculate the capital cost --

MR. LADANYI: In this instance, not in general terms.

MR. KEIZER: In accordance with, in respect to the question that's on the screen, right? EP-5?

MR. LADANYI: Yes. Yes.

MR. MURRAY: That will be Undertaking JT2.17.

UNDERTAKING JT2.17: TO RESPOND TO 1B-EP-5B, AND

DESCRIBE HOW TORONTO HYDRO APPLIES THE DISTRIBUTION SYSTEM CODE.

MR. LADANYI: So if we can go to 1B-EP-9? And here, I asked:

"What percentage of expenditures on OMC, FLISR and volt-wire optimization required to enable reliable and efficient management of DERs, and what percentage of expenditures are required for other reasons?"

And then you explained that you cannot actually disaggregate this. I understand your answer is that some of these expenditures are acquired for DERs, but others are required for other reasons, and you cannot separate them. Is that what your answer is?

MR. HIGGINS: I think the answer would be better characterized as these investments are investments that we are making generally for the purposes stated in the response, to reduce frequency and duration of outages, improve resiliency, et cetera.

There are aspects of these tools that do provide capabilities in respect of managing DERs that sort of come along with these ADMS upgrades. If you wanted to know sort of the particulars of that, I think panel 2 would be better positioned to speak to those investments in detail.

MR. LADANYI: All right. Please turn to 4-EP-33. So in question A, I ask:

> "Does Toronto Hydro charge customers for behind-the-meter connections of electrical vehicle chargers, solar panels and storage batteries?

And if the answer is yes, please list such charges and indicate if they are expected to recover Toronto Hydro's incremental costs. If the answer is no, please explain why not."

And if I see response A, and I read your response A, I read it as you may be charging something or you may not be charging something. Is that right? Or maybe you can explain to me what you are actually saying, in response A?

MS. NARISETTY: So, yes, if a customer is undergoing a service upgrade or a new connection, either as a result of an EV charger being installed or any other increased demand, it follows our, you know, processes as set out in our conditions of service. And we treat it accordingly, to calculate any connection charges to help make that connection.

MR. KEIZER: Sorry, just to clarify, not about the questioning, but in terms of schedule, are we coming up on a break time?

MR. MURRAY: We are. I was hoping to get to the end of Mr. Ladanyi's questions. But perhaps, Mr. Ladanyi, are you going to be much longer?

MR. LADANYI: No. This is actually my last interrogatory that I am referring to. So I probably have a couple more questions here, and maybe take another three or four minutes, and then we are finished.

MR. MURRAY: If the witness panel is prepared to push through, I would propose that we push through and finish Mr. Ladanyi's questions, and then we start with OEB Staff.

MR. KEIZER: That's fine.

MR. LADANYI: So some DERs are for load displacement and some are -- also export power into the grid. Is the connection process more complicated for exporting DERs?

MR. HUNTLEY: There are various levels of complexity depending on the size of the DER that would be exporting to the grid. The larger the DER, the more complicated the connection, because of the greater protection and control measures that have to be taken to protect the grid and the stability of the grid.

MR. LADANYI: So there's a possibility that you would actually charge customers which have a more complicated connection, some kind of a charge? I don't know cost, I don't know how you would calculate that.

MR. HUNTLEY: As part of the connection process for DERs, protection and control costs are included in the connection.

MR. LADANYI: Included in what? In what the customer is charged?

MR. HUNTLEY: That is correct, yes.

MR. LADANYI: Yeah. It's not like free, for everybody?

MR. HUNTLEY: Absolutely not.

MR. LADANYI: But it varies, upon what it is --

MR. HUNTLEY: Yes.

MR. LADANYI: -- based on the hours and staff involvement. Is that right?

MR. HUNTLEY: Yes, that's correct.

MR. LADANYI: At the bottom of page 2, you mention asset and program management. And you say:

"System planning segment includes the capacity planning and grid innovation function responsible for planning the distribution system, future load requirements driven by customer growth and the requisite connection capacity to accommodate current and forecasted level of DERs in the Toronto Hydro service area."

Now, what is requisite connection capacity?

MR. HUNTLEY: In the context of this response, Mr. Ladanyi, it would mean an assessment of the ability to connect DERs, and mitigating any constraints or removing barriers to those connections, should they exist.

MR. LADANYI: So how is requisite connection capacity related to spare capacity?

MR. HUNTLEY: Can you clarify the distinction you are trying to make, Mr. Ladanyi?

MR. LADANYI: As I understand it, any utility system, whether it's gas or electricity, has some spare capacity on the system, and so that it's not always operating at peak, essentially. So that, you know, next incremental amount of capacity totals the whole system. So you must have -- you have some objective to have some level of spare capacity, so that your distribution system can safely operate.

And so requisite connection capacity as I see it, from what you have answered is probably using up some of the spare capacity. So, as I would understand it, so, as more and more connections are made, spare capacity is used up. And then you have some kind of -- and then you need to upgrade the system in some way to have more spare capacity so that you can have connection capacity. So do you have an objective for the requisite connection capacity and spare capacity that you're trying to maintain?

MR. HUNTLEY: The clearest example I can think of that illustrates the point I think you're trying to make is with respect to the management of minimum load-to-generation ratios on specific feeders. They are established IEEE targets that we attempt to maintain. Hence, we've outlined a series of investments in our renewable enabling investment portfolio around renewable battery energy storage systems to manage that particular phenomenon.

MR. LADANYI: That's a very good answer. I've never heard this explained this way. Is there any way you can give me a reference to the IEEE standard that I can look up, myself? You don't have to file it. I just would like a standard.

MR. HUNTLEY: I know it's IEEE 1547. I will have to drill down and check the exact section.

MS. MARZOUGHI: We do make reference to that standard in Exhibit 2B, section E7.2.

MR. LADANYI: 2B, E7.2.

MS. MARZOUGHI: Yes, and it's on page 24.

MR. LADANYI: Page 24. I apologize for not noticing that.

MS. MARZOUGHI: Oh, yes. It's on line 3 and on line

19.

MR. LADANYI: Very good. Thank you very much.

MS. MARZOUGHI: No problem.

MR. LADANYI: These are all my questions. Thank you, panel.

MR. MURRAY: Thank you, Mr. Ladanyi. We will take our second afternoon break. We'll come back at 3:35.

--- Recess taken at 3:22 p.m.

--- Resuming at 3:37 p.m.

MR. MURRAY: We're back to the technical conference, day two, next on the list for panel 1 is OEB Staff. Mr. Wasylyk, I believe you're up first.

EXAMINATION BY MR. ZANINI:

MR. ZANINI: Hello, I'm Daniel Zanini, senior advisor performance analytics and reporting department, OEB Staff. My question is on 1B-EP-15. What value of loss load or value of service number did you use to justify the $1.5 billion over the IRM scenario to prevent that reduction of reliability by 8 percent over the five-year term?

MR. KEIZER: Is there a part of EP-15 that you're referring to? Just so we make sure it's on the screen.

MR. ZANINI: No, there wasn't one specific aspect of that question, it's more the preamble regarding the 1.5 billion to help reduce, or prevent the reduction reliability by 8 percent.

MR. HIGGINS: I'm sorry, can you just repeat the question?

MR. ZANINI: What's the value of loss load or value of service that was used to justify that $1.5 billion over the IRM scenario to help prevent the 8 percent reduction in reliability?

MR. HIGGINS: Is the proposition that there's a -- sorry, a benefit calculation that you're referring to?

MR. ZANINI: Yes, I'm assuming a benefit calculation was performed.

MR. HIGGINS: Just one moment. Sorry, it might take me a in a moment to pinpoint, but there is the benefit cost analysis. I think this is what you're referring to, I'm not totally sure, provided in exhibit 1B, tab 3, I believe it's schedule 1. And there was a value assigned. I'm just scrolling to find it here. Just one moment, sorry.

MR. ZANINI: To save time it doesn't have to be provided now, it can be provided later, that's okay.

MR. HIGGINS: I'm sorry. This is just a lengthy, 68-page section of the document, and for some reason I can't find it right now, but there is a benefit cost calculation that was performed on the benefits of the reliability scenarios that we've put forward as our plan, versus the IRM scenarios, and it is discussed in detail in that section. And the value of service would have been taken from the CIC study discussed earlier today.

MR. KEIZER: Is it at page 60?

MR. HIGGINS: Possibly. Just one moment. Yes. Exactly. Yes, thank you. So, actually the section -- the discussion begins on page 59, and so you'll find there a

quantification of the benefits in that section.
MR. ZANINI: Thanks. Sorry, second question, on 2B-EP-27, this is regarding the unknown cause codes for the interruptions. Does Toronto Hydro perform any type of audits to confirm the unknown cause codes or all its cause codes for interruptions? Because I'm assuming that it's field crews that input cause codes in you're tracking databases?
MR. HIGGINS: That might be a better question for panel because it does start to get into the operational tracking of outage cause codes.
MR. ZANINI: Okay. Thanks.
EXAMINATION BY MR. WASYLYK:
MR. WASYLYK: Great. Thank you, Mr. Wasylyk. Witness panel, good afternoon, may name is Josh Wasylyk, I'm also OEB Staff, senior advisor in application policy and conservation group.
Just a couple of areas of follow-up questions for you. These are going to touch on some areas that you discussed with a few of the other parties over the last day or so.
The first area is with respect to Staff interrogatory, it's 1B-Staff-89, and that is looking at the performance incentive proposal related to your LDR program. And on this one here, so I'm just going to build off a conversation you were having with Mr. Rubenstein yesterday, and this is your response to the factors and considerations that led you to conclude that the shared savings mechanism to level the playing field between the LDR program and load

transfer investments. And with respect to the proposed incentive for the LDR program as part of your response, you indicated that the SSM model where benefits are shared between shareholders and rate payers equally isn't preferred due to the operational and market risk and complexity associated with the successful delivery of the LDR program. And so, as I mentioned you touched on this at a high level with Mr. Rubenstein yesterday, just a couple of follow-up questions.

Can you discuss the operational complexities relative to the current delivery of the LDR program that you expect to see in the future?

MS. MARZOUGHI: So, I think what we're referring to there, and maybe operational complexity is not exactly the right language, but our view is that in order to scale our current LDR program from being more targeted and pilot in nature to being a much larger program, so as you would note from the evidence, it's three times the size in terms of the capacity target, that the shared incentive mechanism is not as effective as the score card mechanism that we have put forward in terms of the supporting our capability building and continuing to scale that program up.

MR. WASYLYK: Okay. So, scale is maybe one of the biggest factors.

MS. MARZOUGHI: Yes, scaling it up.

MR. WASYLYK: Okay. Thank you. So then, I guess, on a related slant, can you also discuss what market risks you're referring to from your response?

MS. MARZOUGHI: Sure. So, actually I believe in another Staff IR, it was Staff-88. We talk about the key factors that influence our ability to go out and do these procurements. And we speak specifically on page 2 about the market dynamics. So, we talk about the fact that there are competing programs and that these things have to be taken into account when you go out and design procurements, and that's something we have to manage as a risk. And then we do speak about this in our evidence as well, that this is a risk that we feel that we have gained a good deal of experience with managing, so we're confident that we can handle it, but that's what we're referring to.

MR. WASYLYK: Okay. Thank you for that response. Continuing along that, you indicate that an appropriate scale then for the shareholder incentive, as you just alluded to there, is forgone utility ROE, which is approximately 3.2 million, that it would otherwise be eligible to earn on the required load transfer capital projects. Which I think the proposed LDR program is proposed to replace. Have I characterized that correctly?

MS. MARZOUGHI: Yes, that's correct.

MR. WASYLYK: Great. So, then to just help my understanding here, if Toronto Hydro proceeds with the LDR program, would the capital that would have been used for the load transfer projects potentially be redeployed to other identified capital projects?

MS. MARZOUGHI: So, in terms of the program that we've put forward, we have assumed that we would avoid or defer that capital in this rate period.

MR. WASYLYK: So then, potentially, the capital that's avoided or deferred could then be used for other projects?

MS. MARZOUGHI: It hasn't been considered as part of the plan that we have put forward.

MR. WASYLYK: Okay. Okay, that's fair. Finally, on this area, can you discuss how Toronto would proceed should it not be approved for the LDR program as proposed, including the performance incentive?

MS. MARZOUGHI: So do you mean specifically, if we were not approved for the performance incentive? Or if we were disallowed to do the program.

MR. WASYLYK: Yeah, maybe say that the program is approved, but the performance incentive is altered in such ways.

MS. MARZOUGHI: Well, we have been -- I don't know if --

MR. KEIZER: I think that would be dependent upon what the Board decided, and what was in the Board's decision at the time as to what they decided to do. I think it is a hypothetical, asking us to --

MR. WASYLYK: Okay. That's fair, we can save this question. Moving on, so those are the questions related to the LDR program. Thank you for those.

I have a couple of additional questions that flow from the BCA calculation that you provided; that is in response to 1B-Staff-49, appendix A. It's the Excel file. I have reserved those for panel 3. I don't know if that's best for me to wait, or go ahead and ask.

MS. MARZOUGHI: It depends on the question.

MR. WASYLYK: Okay. Maybe I will just go through them and, if they are better for panel 3, you can just indicate as much --

MS. MARZOUGHI: Sure.

MR. ASYLUM: -- and I will save them for there. Okay.

So I think this first one is an easy one; I just need the confirmation, just because, as I think you know, the OEB was in the process of developing its BCA guidance, as you have assembled the application and filed it. That subsequently went out in December, by mid-December. And so I appreciate you taking the efforts to get things in so that we could review those. But I just want to confirm consistency.

So as part of your response to 1B-Staff-89, part D, you indicated that the WACC used for the BCA analysis is a nominal WACC that includes inflation. And I think the figures there was the WACC used was 4.17 percent, and inflation assumed at 2 percent. Is that correct?

MS. MARZOUGHI: Correct.

MR. WASYLYK: And I think in the BCA calculator, that is shown as those two numbers just added together for 6.17 percent.

MS. MARZOUGHI: Correct.

MR. WASYLYK: Yeah, okay. Perfect. Thank you, for that.

Now, as I just mentioned, I appreciate that the OEB's

BCA framework and calculator wasn't available. In order to help us assess the consistency with what you put together in the OEB's recent direction, would you undertake to complete the OEB's BCA calculator, which is named the draft phase 1 BCA reporting template, with the inputs that you have included in your BCA calculator?

MR. KEIZER: Yeah, I think that's no problem.

MS. MARZOUGHI: Yes, we can do that.

MR. WASYLYK: Thank you, very much. I appreciate that. And then finally --

MR. MURRAY: Mr. Wasylyk, before we move on --

MR. WASYLYK: Yes. Sorry, Mr. Murray.

MR. MURRAY: -- we want to make sure we give that a number.

MR. WASYLYK: Yes.

MR. MURRAY: That will be undertaking JT2.18.

UNDERTAKING JT2.18: TO COMPLETE THE OEB'S BCA CALCULATOR, NAMED THE DRAFT PHASE 1 BCA REPORTING TEMPLATE, WITH THE INPUTS INCLUDED IN THESL'S BCA CALCULATOR

MR. WASYLYK: Thank you. Finally, in this area, a question around the inclusion of the CCA class 47 tax rate in the BCA calculator? Should I maybe reserve those for panel 3?

MS. MARZOUGHI: Yes, please.

MR. WASYLYK: Okay. That is where I thought the line was going to be drawn, so I am glad that I hit it on the mark and we were able to cross a couple of those out.

Thank you, very much.

MS. MARZOUGHI: Thank you.

MR. WASYLYK: Now I'm going to move to some questions that pick up on of your responses, primarily to 2B-Pollution Probe-34. And this is in discussion around your electric vehicle forecasts, and how they have incorporated it as part of system peak demand.

And you provided some responses to how future EV adoption has been considered as part of system peak demand, and there's a few references, and I will go to those specifically if need be, as well as your evidence at 2B section 4.14.4, where you included an EV volume peak demand graph.

Just a couple of follow-ups there: So in response to Pollution Probe 34, and thank you for pulling it up on the screen, Toronto Hydro noted that it considered the impact of managed versus unmanaged charging, as well as the impact of off-peak ultra-low EV charging rates in its forecast.

And a couple of clarifications: So the City of Toronto's Transform TO has set a goal of 30 percent of registered vehicles in Toronto being electric by 2030. Can you confirm that this was the assumption used for forecasting the impact of EVs in the system peak demand forecast and, if not, please discuss why?

MR. HUNTLEY: It was. I confirm that.

MR. WASYLYK: Perfect. Thank you, very much.

Can you please discuss how the 2022 EV volumes in -- and apologies to whoever is pulling up evidence on the screen -- to Figure 1 of exhibit 2B, section D4, 114? I'll just give it a second, there.

That's the peak demand forecast of EV volumes from 2022 to 2031. Perfect, thank you, very much.

So can you discuss how the 2022 EV volumes in this figure were determined?

MR. HUNTLEY: The volumes depicted in figure 1 were determined from MTO actuals.

MR. WASYLYK: Okay. Were there any other data inputs that were used?

MR. HUNTLEY: No. The MTO actuals provided the basis for that input.

MR. WASYLYK: Okay. Perfect. Thank you for that.

And then, similarly, can you confirm or discuss the data source -- actually, sorry. Can you confirm and discuss how the EV volumes for the future years -- well, you can please speak to 2023 but, from 2023 to 2031 -- were developed and forecasted?

MR. HUNTLEY: The build-out for the model with respect to EVs essentially used inputs from the City of Toronto electric vehicle strategy, along with assumptions around EV sales within the city of Toronto being a percentage of the overall EV sales for the province.

We used projections as well from StatsCan that provided inputs into future EV projections, along with the federal mandate for EV sales with respect to a hundred percent of EV vehicles being zero emissions by 2035.

So those were some of inputs that were used to build out the model to achieve the City of Toronto's EV projections for this time period.

MR. WASYLYK: If possible, would you be able to take as an undertaking to provide reference to those data input sources that you used for the forecast EV uptake?

MR. HUNTLEY: Yes. Sure we can.

MR. MURRAY: That will be Undertaking JT2.19.

UNDERTAKING JT2.19: TO PROVIDE REFERENCE TO THE DATA INPUT SOURCES USED TO FORECAST EV UPDATE

MR. WASYLYK: Thank you, very much. And then, sorry, just a couple more here.

Can you please confirm or discuss the data sources for typical EV charging profiles, and how this was used as part of the system peak demand forecast?

MR. HUNTLEY: With respect to the charging profiles of the various vehicle populations, primarily the light-duty vehicles, reference were used from U.S. DRIVE reports from California. We can provide references for those, should they be required, along with Canadian insurance data with respect to driving habits locally, because that generally maps into the state of charge of vehicles and subsequent charging times. And that is how we build out the charging profile for electric vehicles.

MR. WASYLYK: Okay. Similarly, if you would be able to undertake to provide those references if readily available, that would be helpful.

MR. HUNTLEY: Yes, we can.

MR. MURRAY: That will be undertaking JT2.20.

UNDERTAKING JT2.20: TO PROVIDE REFERENCES USED FOR VEHICLE CHARGING PROFILES, AND INSURANCE DATA REGARDING EV DRIVING HABITS LOCALLY.

MR. WASYLYK: Thank you, for that. Just a couple more here.

In building off the conversation you were having with Mr. Ladanyi just a few moments ago in response to 2B-EP-29, you discussed areas of the city that are likely to experience increases in fleet or commercial EV charging versus residential EV charging. And you had discussed with him that you haven't -- and maybe can first confirm my characterization of your conversation is correct and I understood what you have done, properly, that you haven't forecasted EV charging uptake at a granular level, but rather, your forecast assumed variability across the service territory. Is that correct?

MR. HUNTLEY: Yes, that's correct.

MR. WASYLYK: So then, can you please discuss how, if at all, geographical distribution of EV charging need was determined for EV load forecasts?

MR. HUNTLEY: In building out the model, there were two scenarios that were examined, basically an urban shift, meaning that the uptake of vehicles will correlate with the driving distance of particular consumers, so, the longer the driving distance, the likely better pay-off for the electric vehicle. So there was an urban/suburban shift in one scenario versus another scenario that assumed higher EV demand in the core of the city.

MR. WASYLYK: Okay. And then how were those scenarios considered as you're developing your peak demand forecast?

MR. HUNTLEY: Those scenarios were part of an assessment through Monte Carlo simulation, to determine the median active output that those scenario ranges could yield, and we used the median output as part of our forecast.

MR. WASYLYK: Okay. Thank you for that. And then, so, in response to EP-29C, you noted that EV charging needs are integrated within Toronto's peak demand forecast, which you just discussed there, which is a primary basis for investment plans outlined in the station's expansion and load demand programs.

So I'm hoping you can discuss if and how Toronto Hydro has determined how much EV load to add to each transformer station bus or if this is a consideration.

MR. HUNTLEY: Based on the inputs into the model, we used allocation to each bus based on historical trending of particular load profiles.

With respect to EVs in particular, we did not forecast them at a granular level. They were -- the allocations were made consistent with the outputs of the Monte Carlo simulation that basically assessed the probability on each bus for a particular EV uptake.

MR. WASYLYK: Okay, so would it be a fair characterization that there is the likelihood of some variability in, ultimately, the amount of load that is going to be taking place and the ability for the different station buses to be able to handle the EV charging load in various parts of the city?

MR. HUNTLEY: Yes, that would be a correct characterization.

MR. WASYLYK: Okay. The last one on this area, and this is more just a simple confirmation: Can you please confirm that you've accounted for both residential and commercial EV charging in the system peak demand forecast?

MR. HUNTLEY: Yes, we have.

MR. WASYLYK: Perfect. Great, thanks. Those are the questions in that area. Just one second. I've just got one final area. Thanks for your patience.

These last few questions are follow-ups to 2B-ED-7, and this is with respect to questions and answers related to building electrification. And you had a discussion with Mr. Elson this morning on this topic area. I just had a couple of follow-up questions.

So, in response to questions from Environmental Defence, you noted that Toronto Hydro determined that building electrification -- you know, that's space and water heating -- is not yet a significant driver of growth over the upcoming rate term, '25 to '29 period. You also stated that Toronto Hydro does not track customer heat source by type, for example gas- heated versus electrically heated homes. So a couple of follow-ups here.

And, in addition, you had a conversation with Mr. Ladanyi, as well, about home heating electrification and the proliferation of heat pumps and the speed of adoption.

And you said that you're monitoring this. So thanks for that clarification.

Can you discuss what type of coordination and discussions Toronto Hydro has had, if any, with Enbridge Gas, to better understand the current and future building stock and to discuss changes in trends in relation to building electrification and home heating and building heating?

MR. HUNTLEY: Toronto Hydro has engaged with the IESO as part of regional plannings, and, as part of the current cycle, there have been engagements with Enbridge Gas to discuss forecast inputs and potential scenarios.

MR. WASYLYK: Okay, so is that that -- are you -- has Toronto Hydro engaged in any direct discussions with Enbridge Gas on this topic?

MR. HUNTLEY: Not to my knowledge.

MR. WASYLYK: Okay. Thank you very much. Okay. And has Toronto Hydro followed the recent Canada Greener Homes or the Ontario version, the Home Efficiency Rebate Plus program, and the success of that program on home heating and the adoption of heat pumps?

MR. HUNTLEY: One moment. Thank you. As far as capital planning is concerned, we have not considered that particular input.

MR. WASYLYK: Okay. That's fair, and these are recent developments, so I appreciate that response.

Finally, you talked with Mr. Elson this morning regarding behind-the-meter information, customer surveys and the like. Can you please discuss or maybe confirm your earlier conversation and provide any -- well, maybe first, please discuss any data that Toronto has developed or has used in reference to inform its understanding of consumer behaviour with respect to building electrification in homes and commercial buildings.

MR. HUNTLEY: Thank you. With respect to the intelligence that might have been gathered from customer engagements, that may be an appropriate question for panel number 2.

MR. KEIZER: Actually, if it's customer engagement, it's panel 3.

MR. HUNTLEY: Oh, panel 3, sorry.

MR. KEIZER: Oh, sorry. It depends what kind of customer engagement. Sorry, I'm incorrect.

MR. WASYLYK: Okay, so it could be maybe you can speak to it now, and you can tell me which panel better might be better served to respond to it. Examples would be customer end-use surveys that you might have.

MR. KEIZER: If it's ordinary course customer care, it would be panel 2.

MR. WASYLYK: I don't think it's going to be because I would be surprised if the customer care team would have that sort of -- that would be more technical data. It would be essentially assessing kind of building stock and talking to building owners and different people like that on square footage of the buildings and kind of what heating systems are in place and those sorts of technical aspects of buildings. If the customer care group does have that information, I'm glad to try them.

MR. KEIZER: You know, just to be clear, to make sure, we can take an undertaking to clarify.

MR. WASYLYK: Yes. No, that's fine.

MR. MURRAY: So that will be undertaking JT2.21.

UNDERTAKING JT2.21: TO REVIEW AND PROVIDE ANY CUSTOMER END USE SURVEYS OR ANY ANALYSIS OF DATA OR TRENDS RELATED TO ENERGY EFFICIENCY RETROFIT PROJECTS OR PUBLICLY AVAILABLE ENERGY CONSUMPTION DATA THAT HAVE BEEN USED TO INFORM ITS UNDERSTANDING OF CONSUMER BEHAVIOUR WITH RESPECT TO BUILDING ELECTRIFICATION, ON A BEST-EFFORTS BASIS

MR. WASYLYK: And maybe -- okay. I think maybe, then, just to maybe clarify the undertaking so that it's clear and you can respond to it in a more comprehensive manner, maybe the undertaking to be for Toronto Hydro to review and provide any customer end use surveys or any analysis of data or trends related to energy efficiency retrofit projects or publicly available energy consumption data that have been used to inform its understanding of consumer behaviour with respect to building electrification. Is that fair?

MR. KEIZER: I'll do it on a best efforts base.

MR. WASYLYK: Of course. Okay. Thank you very much, panel. Those were all my questions. I appreciate the responses.

EXAMINATION BY MS. DEFAZIO:

MS. DEFAZIO: Hello, Panel, I'm Margaret DeFazio, a senior advisor at the OEB. I would like you to first pull up the electric vehicle charging connection procedures issued by the OEB on February 16th of this year. This contains a consolidation of procedures, timelines, workflows and template forms issued by the OEB intended to streamline processes for connecting public charging facilities that commonly service multiple electric vehicles. Are there any impacts that Toronto Hydro has assessed for a year to be greater than a million dollars, either in capital or operating due to this?

MS. NARISETTY: Can you please clarify the question, again, Ms. Margaret?

MS. DEFAZIO: In reviewing this document, has there been any changes to your capital or OM&A budgets that are a million dollars or more for the forecast period?

MS. NARISETTY: Yes. Subject to check, I don't think so.

MS. DEFAZIO: Thank you. Could you please quickly list investments -- sorry, briefly list any investments being made to reduce foreign interference caused outages? My apologies, this is in reference to 1B-Staff-09.

MR. KEIZER: Is there a part of one?

MS. DEFAZIO: Sorry, I did not note a part. There might be an outage breakdown further down. Outage cause codes. I don't believe there was much in the IR, I'm just looking for what investments you make that would reduce foreign interference caused outages.

MR. HIGGINS: So, with respect to foreign interference outages, that would include various external factors like animal contacts, and I believe -- sorry, just one moment. Yes, okay. Sorry, I lost my reference, yes, animal contacts, vehicles, foreign objects, things like that. So, previously we mentioned, for example, with animal contacts, as we go and we rebuild overhead equipment, we would be installing animal guards but also, as part of worst performing feeder program, we would be doing that more reactively in response to situations that we're seeing.

With respect to vehicles, there's not always a lot we can do. But if there's a particularly high risk area we can install bollards, which we occasionally do, and then there's probably a number of kind of smaller factors that would come into play that can't necessarily be managed. But that would be a couple of examples, yes.

MS. DEFAZIO: Thank you. This question would be in way of an undertaking, if you could -- oh, what's going on with the screen here. There we go. Okay. Could you provide a comparison of the average expenditure required to reduce marginal outages due to defective equipment versus tree contact, versus foreign interference?

MR. HIGGINS: No, I don't think that would be possible.

MS. DEFAZIO: Okay. If we could go to IR 1B-Staff-91. If you scroll down there's a figure. So, this was, our apologies, this figure was produced using a ten year rolling average. Could you reproduce it using a five year rolling average, as well as the underlying table over the same timeframe?

MR. HIGGINS: So, we may need a bit of a clarification. Because, I guess, when we responded this, the way we understood the question was that you were looking for us to replicate, essentially, the analogous methodology that we used to come up with the five year targets, but using a ten year window instead.

And we felt that the appropriate way to do that would be to use ten years across the board, a rolling ten year average. And, yes, using a rolling ten year average, and then calculating the standard deviation for the target on that same basis.

If we move to five years, we may start to mix apples and oranges, but if there's a specific request, like, that we -- a specific methodology that the OEB would like to see played out, we could consider that.

MS. DEFAZIO: Well, I think it's --

MR. HIGGINS: Or Staff, sorry, not the OEB.

MS. DEFAZIO: That's okay. As you noted, we typically use a five year, not a ten year, and I think we worded the question incorrectly, which resulted you doing the ten year, so my apologies for the extra work.

MR. HIGGINS: Well, the target is already set in our pre-filed evidence on a five year basis.

MS. DEFAZIO: Could we just see the graph over the same time period with the five year? Going back to say, 2013, so we can see the trend over time? Not necessarily redoing the target, but what was the...

MR. HIGGINS: Going back to 2013?

MS. DEFAZIO: Yes.

MR. HIGGINS: We could produce that, yes.

MS. DEFAZIO: Thank you.

MR. MURRAY: That will be undertaking JT2.22.

UNDERTAKING JT2.22: TO UPDATE THE GRAPH IN 1B-STAFF-91 TO INCLUDE THE FIVE-YEAR ROLLING AVERAGE BACK TO 2013.

MS. DEFAZIO: So, if we could please go to exhibit 2B section D3, Appendix A, page 5, which has table 4. There we go.

Yesterday we had some -- or you had some discussions about reliability modelling and discussions around using asset age as an input versus asset condition, which when we look at the ACA, you have a large number of assets on the ACA. Could you just list and briefly describe why there are some assets that are not on this list or that you don't collect condition for?

MR. HIGGINS: Just one moment. So, if I could take you to 2B-SEC-36. So, what you have here is, in table 1, is a list of major system asset categories with yes, no, or partial for whether or not any same model exists.

There's an example here, I guess, because the question was asking for -- sorry, just a moment. Right, the question was asking for the percentage breakdown between the two. So, 37 percent of the money that we spend is on assets that do have a condition model. Out of the remaining assets, there are the three biggest contributors to total spending as it says here in the response on line 5, would be underground primary cable, underground duct banks, and meters. And so, for example, cables and ducts would be an example of an asset class that is not conducive at this time to developing a condition model. And there's a number, I believe in another interrogatory, we discussed overhead transformers, and the reasons there's not currently an economical way to collect condition information on those assets. So the response would vary depending on asset class, but that should give you a sense, I think.

MS. DEFAZIO: Perfect. Thank you for pointing that out.

If we could go to 1B-Staff-90, please? If you scroll down -- I didn't note the A, B or C. But in this, Toronto Hydro states:

> "Toronto Hydro plans to improve SAIDI will have benefits for outage duration during adverse extreme weather events, whether those events meet the statistical classification threshold for major event days or not."

There you go, at the beginning of B. Have you defined what constitutes outages due to adverse and extreme weather to versus just normal weather?

MR. HIGGINS: I don't have the precise definition for adverse weather on hand, but it is a defined cause code. And so we would follow that definition when labelling outages. And then extreme weather is a little more to do, just with the severity. Is it a major outlier weather day, as opposed to adverse weather, which is more of a formal reliability definition.

MS. DEFAZIO: Okay. Thank you. And would you say you have experienced or Toronto Hydro has experienced adverse and extreme weather events that did not meet the OEB or IEEE major event-day criteria. And could you describe, if you have?

MR. HIGGINS: Yes, quite often. It's one of our material cause codes for reliability, so it could be any variety of weather conditions that would trigger an outage.

MS. DEFAZIO: So we were talking about adverse and extreme weather. I understand the adverse weather cause codes when comes to extreme weather. Would you categorize that separate, outside of adverse weather? Or kind of in the same category?

MR. HIGGINS: Maybe just in the interests of being helpful here, 1B-EP-4, if we can go there? I guess we did get a question on this; I forgot about the definitions.

And as we note here on line 20, we define extreme and adverse weather as rain, ice storms, snow, winds, extreme temperatures freezing rain, frost, et cetera, that are likely to affect grid operations.

The extreme weather one is really more of a matter of degree; is it a particularly extreme event, essentially.

Could you just repeat your question?

MS. DEFAZIO: Okay. So, because customers have said that they are interested in reducing adverse and extreme weather, I am wondering if you have drawn a line or a criterion to say what's normal weather, your typical summer storm or an extreme weather storm?

MR. HIGGINS: We haven't drawn a line per se. We would expect -- generally, the expectation around the effects of climate change is that we would see both more frequent and more severe events. Now the extent to which that actually happens will be -- remains to be seen. But that's generally what we are referring to, is some increase in both the frequency and severity of different kinds of events.

MS. DEFAZIO: Okay. Thank you. If we go to exhibit 2BC, page 8, there's a listing of the historic major event days. Would Toronto Hydro agree that most of its major event days are characterized by extreme weather events?

MR. HIGGINS: Historically, yes.

MS. DEFAZIO: Thank you. Toronto Hydro says it has challenged itself to set modest improvement target for SAIDI, which involves some significant incremental spending. Did Toronto Hydro consider holding SAIDI constant, and challenging itself to keep costs as low as possible?

MR. HIGGINS: So maybe if we can zoom out for a second? The plan in the Distribution System Plan that is before the board is based on a number of different factors, including the results of customer engagement. When it comes to reliability and price, those two factors continue to be items No. 1 and 2 essentially, for customers. And customers do prioritize managing outage duration over frequency.

Our overall objective, recognizing that the top priority for customers continues to be affordability, was to try to achieve the balance of objectives, which is maintaining reliability at the most affordable, you know, cost that we could, taking into consideration various other factors, including longer term investment needs, general system stewardship need, growth needs, et cetera, so balancing all these different factors.

With respect to the objectives that we set on SAIDI and SAIFI, we have a near-term objective, which I think we have been -- we have tried to be clear about in the evidence, which is we are looking to do no more than is necessary to maintain reliability. And the primary way that we are expressing that objective, when it comes to our system renewal program is through the SAIFI performance incentive measure, the SAIFI defective equipment performance incentive measure.

On the SAIDI side, the objective with respect to system renewal is fundamentally the same; it is to maintain reliability. However, we are also making investments in this rate period that are part of our longer term grid modernization road map which are intended to position our grid and our operational capabilities to handle the pressures that are coming, that we believe are coming from higher utilization, greater sensitivity to outages on behalf of customers, which we are anticipating as a result of electrification, pressures of climate change, pressures from expanding use of DERs on our grid.

And it so happens that making those investments now we recognize will have some incremental benefit on SAIDI. We don't expect it to be significant in this rate period, but because we are making these incremental investments and we are asking for funding for those investments, we did want to set an objective that recognized that those benefits may be achievable using these new technologies, which is why we went with an improvement objective on SAIDI.

MS. DEFAZIO: Okay. Thank you. This next question, I debated if it was panel 1 or panel 1, so I will get started. And if you would like me to move it to panel 2, please let me know.

If we could go to 2A-Staff-114? And I am pretty sure you can handle the first question: Can you very briefly describe to me what an MCS is? That's the monitoring and control system for DER facilities.

MR. HUNTLEY: Just so I understand the question, you would like a description of what that is?

MS. DEFAZIO: Yeah.

MR. HUNTLEY: Okay. The monitoring and control system is essentially the interface between the customer's DER equipment and a Toronto Hydro SCADA system.

MS. DEFAZIO: Okay. Does Toronto Hydro install these systems at all DER sites?

MR. HUNTLEY: We require them at all DER sites, yes.

MS. DEFAZIO: Is it correct to say that an MCS is installed for new DERs, regardless of the source of energy, that is, whether it is a renewable or a non-renewable site?

MR. HUNTLEY: I would just like to offer one clarification to your prior question. It is for DER sites above 50 kilowatts.

MS. DEFAZIO: Thank you. Regardless of energy source?

MR. HUNTLEY: Correct, yes.

MS. DEFAZIO: Okay. And, if there's a customer site that does not have a DER, is it correct to say there would be no need to install an MCS?

MR. HUNTLEY: The purpose of the MCS program is directed towards DER sites.

MS. DEFAZIO: Thank you. So, I was looking to confirm the spending on the RGCRP eligible items for the 2020 to 2022 as this is the time frame being requested for clearance, and the renewable-enabling investment variance account. So I would like to confirm that the expenditures under the GPMC program that are part of the RGCRP -- I'm sorry for all the acronyms -- those investments were to connect renewable generation only.

MR. MUNDENCHIRA: Yes, that's correct.

MS. DEFAZIO: Thank you. Now, in the answer to 2A-Staff-114, the response referred to 2A-Staff-108 and described the MCS as renewable-enabling generation -- sorry, that it enabled future generation. But I think in fact you could provide me a list of the number of connection points and sites that were connected during the

2020 to 2022 time frame. There's a preliminary list shown in 2B-E5.5. Oh, I didn't note the page. If you scroll down --

Anyways, what I'm looking for is: Could you please confirm the actual numbers of MCS and antenna installation programs and DER -- sorry, MCS buy-back programs that are included this the RGCRP funding requested for clearance from 2020 through 2022.

MR. HUNTLEY: The list of sites?

MS. DEFAZIO: Yes -- sorry, the numbers. I don't want a list of addresses. Just, you know, in the application you have a list of a buyback program, antenna installation program, and new DER metres and RTUs. We're looking for the actual work that was completed for the RGCRP funding that is in the DVA.

MR. HUNTLEY: Yes, we can take that by way of undertaking.

MS. DEFAZIO: Perfect. Thank you.

MR. MURRAY: That will be undertaking JT2.23.

UNDERTAKING JT2.23: TO CONFIRM THE ACTUAL NUMBERS OF MCS AND ANTENNA INSTALLATION PROGRAMS AND MCS BUYBACK PROGRAMS THAT ARE INCLUDED THIS THE RGCRP FUNDING REQUESTED FOR CLEARANCE FROM 2020 THROUGH 2022.

MS. DEFAZIO: If you could, please move the screen to 2-Staff-109. As part of 2-Staff-109, Toronto Hydro filed an Excel spreadsheet, Appendix B, which is the OEB appendix 2-FB, which is the calculations for renewable-enabling generation connections direct benefits/provincial account.

And the calculations in this spreadsheet include assets that have an average lifespan of 27.5 years' depreciation, and that was stated that that is a blended -- a number of assets blended together on a weighted average have a 27.5-year depreciation.

If you scroll down a little bit further down the page, you may see it. Try the ISA page, the tab to the left. No.

MR. MUNDENCHIRA: If I could be of help, it would be the tab called "REG A," three to the right, three tabs to the right, further down.

MS. DEFAZIO: There you go. Oh, just up a bit: 27.5 years. That's the amortization period average for those assets. Could we get a breakdown of how that calculation was arrived at for the 27.5-year depreciation period, please?

MR. MUNDENCHIRA: Yes, we can. It was a simple average of the highest and lowest potential assets, but we can provide those.

MS. DEFAZIO: Thank you.

MR. MURRAY: That will be undertaking JT2.24.

UNDERTAKING JT2.24: TO PROVIDE A BREAKDOWN OF THE CALCULATION OF THE 27.5-YEAR DEPRECIATION PERIOD SHOWN IN 2-STAFF-109, APPENDIX B; TO REDO THE CALCULATION USING THE UPDATED DEPRECIATION RATES FROM THE CONCENTRIC STUDY PROPOSED IN THIS APPLICATION.

MS. DEFAZIO: And also as part of that undertaking, could you redo that calculation using the updated depreciation rates from the Concentric study that is being proposed in this application?

MR. MUNDENCHIRA: Yes.

MS. DEFAZIO: And, as well, one more item, resubmit the calculations using the new depreciation rates as they apply in the -- I guess it was '23 to '29 years?

MR. MUNDENCHIRA: Yes.

MS. DEFAZIO: Thank you. Okay. We've talked a lot today about useful life, and I would just like to clarify a couple of items around useful life and depreciation life. If you would like, you could pull up 2B-Staff-29. Okay. So here we talk and in all the Concentric reports, we talk about useful life and depreciation life. Is it fair to say those are the same things or have the same duration in your application?

MR. HIGGINS: Yes, with the exception, I think, of one asset class.

MS. DEFAZIO: Okay. Thank you. So the APUL, assets past useful life, we could also make it longer and say "assets past depreciation life." It would be almost -- except for that one asset class, it would be interchangeable?

MR. HIGGINS: So mathematically, yes --

MS. DEFAZIO: Okay.

MR. HIGGINS: -- it would be the same. I don't necessarily -- maybe just to check what I said on the first response, I don't know that we would look at those two categories, the useful life and the depreciation life, as being the same thing necessarily, but, in this iteration of our planning cycle, they have converged, yes.

MS. DEFAZIO: Yes, okay. So can you confirm that depreciation studies and the Concentric depreciation study accounts for all causes of asset retirement?

MR. HIGGINS: I would just refer you to Concentric's response to this question in part B of 2B-Staff-129, on page 2, where they say that the depreciable life of assets is based upon et cetera, et cetera, historical --

MS. DEFAZIO: Okay.

MR. HIGGINS: -- retirements, and they list a number of factors that are included.

MS. DEFAZIO: Can you just describe some of the ways assets are retired that are beyond Toronto Hydro's control, just as examples?

MR. HIGGINS: I guess it depends on what exactly you mean by beyond our control. But I would say that, you know, failures themselves reactive replacements are, to some extent, beyond our control and random, and there are assets that fail at a young age, and then there's compliance driven reasons, for example, such as PCB related replacements would be a couple of examples.

MS. DEFAZIO: Would road widenings or roadwork relocations be an example?

MR. HIGGINS: Yes.

MS. DEFAZIO: Okay. Automobile collisions, would they be another example?

MR. HIGGINS: Yes.

MS. DEFAZIO: Thank you. So, in 2B-Staff-129, you use a term called average service life. And average service life you say is calculated on the basis of what Toronto Hydro would call failure curves, i.e. probability of failure curves on the basis of a utility's failure data as opposed to retirement data. Yes, there you go, lines 23 to 25.

So I'm just trying to clarify the wording we're using, so useful life and depreciation life are kind of the same thing, and average service lives are those lives what you would expect if you only replaced due to failure curve.

MR. HIGGINS: I'm sorry, where are you seeing average service life? I'm just missing something on the screen. Okay, let me pull that up.

MR. HIGGINS: Which part of the question are we looking at?

MS. DEFAZIO: Sorry, you're right, it's not right there. Let me find it. My apologies, it's Staff-123 in response A.

MR. HIGGINS: I apologize, can you repeat the question?

MS. DEFAZIO: Sorry, and that would go down to, sorry, page 2, line 16. 15, 16. So, I'm just trying to clarify some of the terminology that assets past useful life are average useful life and depreciation life have been calculated the same, and average service life is the life based solely on a failure curve, without external forces.

MR. HIGGINS: So, I don't see the specific language.

I don't know if we're looking at the same interrogatory. I can discuss the concepts if you like.

MS. DEFAZIO: Someone whispered in my ear I've got it wrong again, 131, page 2, line 16. There you go. Sorry, about that.

MR. HIGGINS: Okay, that's helpful, yes. I remember this now. So, maybe I can just -- because this is a bit of a tricky topic. So, what we've said here is we are assuming, in our response, that OEB Staff is referring to the difference between average service life determined on the broader set of retirement causes we just discussed for depreciation purposes, versus something that would be more focused upon failures, and I just kind of assumed here it would be, you know, exclusively failures. So, one of the things that we can develop to inform the selection of useful life values or, more importantly, to come up with probability of failures calculations would be failure curves. Now, that's kind of a spectrum. There's also, you know, useful lives I think can be defined a number of different ways and mean service life can be defined in a number of ways.

For most of our recent history since we did the Kinectrics report in 2009, I believe it was, that was defined as simply the mean average between what Kinectrics came up with as the minimum and maximum useful life, and we used that going forward as a reference point for our APUL calculations and certain other analytics where that data point was useful.

I think what you've seen, and maybe just to clarify, because I am getting the impression that others have the impression that the useful lives and the depreciation lives are one and the same, and while mathematically that is the case as of right now, the timeline I think matters there. The bigger changes resulting from the Concentric study are actually to the lengthening of depreciation lives, and it's the depreciation lives that have come more so into alignment with of the engineering useful lives as a result of the depreciation study.

We did look at it from the other direction, which is based on this latest information coming from the depreciation study. Do we feel comfortable or do we think it's appropriate making some adjustments to the engineering useful lives? And there was a handful of cases where we did decide to make those adjustments, most of them were very minor, to bring into alignment, a couple were more significant, which we can discuss, but that was kind of the order of operations.

All of which to say our engineering useful lives are still predominantly grounded in the original Kinectrics study.

MS. DEFAZIO: So, yes, no. Not issues with what you've described, I just want to clarify that throughout the application when you talk about useful life, it has the same duration as your depreciation life, and you've confirmed that through providing us this table in 2B-Staff-129.

MR. HIGGINS: That is correct. And the exception there would be a specific type of cable that's noted in the table.

MS. DEFAZIO: Perfect. And then average service life described here, slightly different name, but that would be the life based off a failure curve, if there was no outside forces like wind storms or, you know, car accidents, road widenings it would that that failure curve?

MR. HIGGINS: Yes, perhaps we overinterpreted the Staff's question here. I guess what we were putting up as an example would be something that is more purely based on failures, which that kind of an analysis would result in -- you could extract an average service life value from that if you want to call it an average service life value, this is where we get into some semantics. But you could extract an average life for an asset from that kind of a curve, if you wanted to, but that kind of analysis would typically be used for actually doing, you know, predictive failures analysis and performance analysis and things like that, so.

MS. DEFAZIO: Excellent yes. So, in 2B-Staff-129, we have the depreciation life, and the useful life, which have the same duration for the assets that were listed in that table. Would you -- you would not plan to replace your assets in the engineering world based on your depreciation life, you would plan based off the failure curves and the asset condition assessment. Would that be correct?

MR. HIGGINS: Among other factors, yes.

MS. DEFAZIO: Yes, other things come into play. Could you give us that life as a comparison? Do you have that life value that you could put in as another column in this table?

MR. HIGGINS: So, we haven't done a study specifically to look at what a single useful life value might be for the purposes of failure related analysis.

MS. DEFAZIO: Would you expect it to be longer that the depreciation life?

MR. HIGGINS: It likely would in most circumstances, but the question is just by how much. And this is where the issue becomes, and this is an issue, I think this is what we tried to discuss in 131. It's an industry-wide challenge to develop failure datasets that are long enough and rigorous enough and accurate enough to actually drive the kinds of predictive analytics that say a life insurance company could do, right?

It's our physical assets are much more -- the data is just not as good. We are improving, and we have done some -- I think we discussed this yesterday, we have done some work with a consultant to start to explore what might be possible in the future. But for now, I think we have discussed in other parts of the evidence, we are relying upon our asset condition model, reliability and performance trends, and various other factors to determine the level of investment.

MS. DEFAZIO: Thank you. If we can now go to 2B-Staff-135. Here, you produced a table showing the number of MSs to be decommissioned over 2025 to 2029. Will there be any costs in the decommissioning of these MSs in the forecast period?

MR. HUNTLEY: Yes, there will be.

MS. DEFAZIO: Where are they included in the DSP? And can you break the costs out?

MR. HUNTLEY: We can take it via undertaking.

MS. DEFAZIO: Thank you.

MR. MURRAY: That will be Undertaking JT2.25.

UNDERTAKING JT2.25: TO BREAK OUT THE COSTS FOR DECOMMISSIONING OF MSs IN THE FORECAST PERIOD WHERE THEY ARE INCLUDED IN THE DSP (REF: 2B-STAFF-135)

MS. DEFAZIO: Okay. If we could go to 2B-Staff-188? Toronto Hydro has referenced the Building Transit Faster Act. What agreement have Toronto Hydro and Metrolinx come to regarding the apportionment of relocation costs under the Building Transit Faster Act, Part IV, section 51.

MR. KEIZER: I think we'll have to do an undertaking for that one.

MS. DEFAZIO: Okay.

MR. MURRAY: That will be Undertaking JT2.26.

UNDERTAKING JT2.26: TO DESCRIBE ANY AGREEMENT BETWEEN TORONTO HYDRO AND METROLINX REGARDING THE APPORTIONMENT OF RELOCATION COSTS UNDER THE BUILDING TRANSIT FASTER ACT, PART IV, SECTION 51 (REF: 2B-STAFF-188).

MS. DEFAZIO: So, also on 2B-Staff-188, Toronto Hydro states in the first -- on the screen, and the first line of its response:

"The decrease in capital contributions is attributed to increased expansion work over the forecast period to meet anticipated load growth. In particular, forecast expansion work associated with relocations under the Building Transit Faster Act contributes to..."

...and it goes on. But load growth and relocations are two separate things. Load growth is funded by the DSC, relocations funded by Building Transit Faster Act, and the Public Service Works and Highways Act.

So these are not the same thing. Can you explain the -- can you please clarify the reason for the decrease in contributions?

MR. HUNTLEY: Thanks for the question, Ms. Defazio, but I think panel 2 would be better suited to answer that particular question.

MS. DEFAZIO: Okay, panel 2. There was a letter issued by the OEB on January 29, 2024, titled, "Proposed amendments to the distribution system code to enable flexible hosting capacity arrangements."

And these amendments allow distributors to enter into flexible hosting capacity arrangements with generators.

Will Toronto Hydro consider or -- and are you considering, flexible hosting arrangements with generators in place of the feeder-level batteries?

MR. HIGGINS: In our grid modernization strategy evidence, we do cover a number of topics that are related to the grid readiness aspect of our strategy. And grid readiness is essentially the name we have given to the category that deals with accommodating more DERs, facilitating them, and integrating them into the system.

And as part of the facilitation aspect of that strategy, we are looking down the road at developing capabilities that would allow us to overcome some of the harder limits that we have on our system in terms of accommodating DERs.

One of those things is flexible connections. And if you can go to section D5, page 44, this is in the innovation subsection, which is part of the grid readiness portfolio.

I'll just wait for the table to come up. In the first row, you will see a brief capsule description there of the flexible connections, pilot work that we are proposing for our innovation program.

So this is -- it is still early stages around some of these things, so whether or not this serves to become a replacement for the battery option remains to be seen, upon what time frame. But we do know other jurisdictions have explored this kind of thing successfully.

However, with flexible connections, it is a very technical and specific arrangement that is, I think, going to end up being unique to every service territory and system. So we do have a bit of a road ahead in terms of testing and piloting different options, but it is something that we are looking to develop over the next rate period.

MS. DEFAZIO: Perfect. Thank you. If we can go to

2B-Staff-162, please, and question C? Question C just states that the Horseshoe system has a high proportion of overhead feeders. Can you give an approximate or a ballpark number on how much of the Horseshoe is overhead, versus underground? And it can be by, I don't know, by circuits or circuit-kilometres, or customers, whatever is kind of easier to apportion it, what's overhead versus underground.

MR. HIGGINS: In the interests of time, because it will probably be like finding a needle in a haystack, we can respond to that through an interrogatory, yes -- or through an undertaking.

MS. DEFAZIO: Thank you.

MR. MURRAY: That will be undertaking JT2.27.

UNDERTAKING JT2.27: TO PROVIDE AN APPROXIMATE VALUE FOR HOW MUCH OF THE HORSESHOE SYSTEM HAS OVERHEAD FEEDERS, VERSUS UNDERGROUND.

MS. DEFAZIO: Okay. Can you please pull up the 2022 scorecard. That's in exhibit 1B, tab 3, section 2, appendix A. Okay.

So on this scorecard, we can see that it goes from 2018 to 2022. Can you scroll down to the next page, please? Can you just keep going to the second page of the scorecard, please? That's not the actual scorecard. Yeah. Okay.

Lawren is asking, do we want to break and pick this up tomorrow?

MR. MURRAY: I think, Ms. Defazio, do you get a sense, will we be done in the 15 minutes? I get the sense, probably not.

MS. DEFAZIO: Probably not.

MR. MURRAY: So rather than keeping people here till 5:15, and then having people sprint off to wherever their competing priorities may be, it might make sense just to start again at 9:30.

MR. KEIZER: Do we know how much longer Staff will be? Just for us to coordinate.

MR. MURRAY: I would say less than an hour? Is that fair?

MS. DEFAZIO: Yeah, less than an hour.

MR. KEIZER: Okay. That's fine.

MR. MURRAY: So why don't we start again tomorrow at 9:30?

MS. DEFAZIO: Thank you.

--- Whereupon the conference adjourned at 4:58 p.m.