

ONTARIO ENERGY BOARD

FILE NO. **EB-2024-0115** Hydro Ottawa Limited.

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EB-2025-0115

THE ONTARIO ENERGY BOARD

Hydro Ottawa Limited

Application for electricity distribution rates

and other charges beginning January 1, 2026

Technical Conference held in person and virtually from 2300 Yonge Street, 25th Floor, Toronto, Ontario, on Tuesday, September 23, 2025, commencing at 9:30 a.m.

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TECHNICAL CONFERENCE

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MICHAEL MILLAR Board Counsel

IAN RICHLER

JULIA NOWICKI

KHALIL VIRANEY Board Staff

FIONA O’CONNELL

RITCHIE MURRAY

DALIANA COBAN Hydro Ottawa Limited

JONATHAN MYERS

APRIL BARRIE

CLEMENT LI Building Owners and Managers Association (BOMA)

TOM LADANYI Coalition of Concerned Manufacturers and Businesses of Canada / Energy Probe Research Foundation

MICHAEL BROPHY Community Action for Environmental Sustainability (CAFES) and Pollution Probe

LAWRIE GLUCK Consumers’ Council of Canada (CCC)

MARK RUBENSTEIN School Energy Coalition (SEC)

JANE SCOTT

MARK GARNER Vulnerable Energy Consumers’

BILL HARPER Coalition (VECC)

ALSO PRESENT:

LIANNE CHARTRAND Hydro Ottawa Limited

SHAYNE THOMPSON

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Tuesday, September 23, 2025

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

M. MILLAR: Good morning, everyone. I think we are ready to go. Welcome to Day 2 of our technical conference for Hydro Ottawa. Ms. Coban, are there any preliminary matters we need to review?

Preliminary Matter

D. COBAN: There are a couple of preliminary matters I wanted to put on the record this morning. The first is to just let the parties know that in the process of reviewing the transcript we are going to be filing a letter sometime tomorrow to correct the transcript, including the wording of certain undertakings which, in our view, did not accurately capture what was agreed to be provided. So that should be filed tomorrow. I also wanted to just clarify an exchange between Ms. Flores and Mr. Gluck yesterday. It's at page 139 of the transcript that was issued. Ms. Flores indicated that we were not able to provide the Planning Forecast beyond 2030 up to 2035. We've looked into it and have confirmed that it is possible to provide it up to 2035, so we will amend the language of the undertaking JT 1.28 to reflect this update.

And the other matter I wanted to raise is Mr. Hawthorne and his exchange with Mr. Rubenstein on the pole program. He had a clarification that he wanted to provide to certain information that he provided Mr. Rubenstein about that pole program, so I will just ask Mr. Hawthorne to come on the record and provide that clarification now.

S. HAWTHORNE: Hi, good morning, everyone. In my exchange with Mr. Rubenstein yesterday regarding the pole renewal program when speaking to undergrounding I noted that we plan to underground 50 poles at 50 metre spans, that should be corrected to 30 poles at 50 metre spans. Thank you.

M. MILLAR: Okay. Is that everything, Ms. Coban?

D. COBAN: The only other matter to put on your radar is that we did put an undertaking on the record to answer facts, VECC's questions that were submitted in writing, but we have not done the same for the other parties that submitted questions in writing. So I was wondering if you wanted to enter those as formal undertakings?

M. MILLAR: Yes, why don't we do that. And what we did last time was first marked the questions as an exhibit and then mark the undertaking to respond to those questions. I don't have the list in front of me, Ms. Coban, do you?

D. COBAN: I do not, but I can come back to you after the break with the list.

M. MILLAR: We can do it at the break, okay. That would be great. Thank you very much. And I guess just a reminder for all of us, myself certainly included, it's best where we can summarize the undertakings and kind of give a pithy one-liner on what the undertaking is right when we give it. I know sometimes I certainly sympathize for the court reporter trying to go through the back-and-forth sometimes, so whenever we can I suggest either the questioner, or the witness, or perhaps myself or Ms. Coban, can try and state succinctly what the undertaking is for and that kind of hopefully can clear up a lot of the problems sometimes we have after the fact.

M. RUBENSTEIN: Can I confirm that what is governing is not the title for what's in the transcript, the titling, it's really what the conversation is, is what governs what the undertaking will be?

M. MILLAR: Yes, I mean, sometimes it's difficult to discern exactly what was agreed to and what was not, which is why it's helpful to summarize it at the end and hopefully everyone agrees that way. Certainly you can look back to what the actual conversation was to inform that. We've had a few disputes about that at the end, but my experience is the better job we do at summarizing the undertaking in real time the less problems that we have. So we will all try to do that, we will do our best.

Okay. Unless there are any other preliminary matters, I am happy to hand the floor to Mr. Li.

C. LI: Okay. Can you guys hear me?

M. MILLAR: Yes.

Examination by C. LI

C. LI: Okay, thank you. Good morning, everyone. My name is Clement Li, representing Building Owners and Managers Association Ottawa or BOMA Ottawa. I have a few clarifications or follow-up questions related to your responses to our IR questions. Both Panel 1 and Panel 3 are listed on the specific responses that I plan to go to. So I will go ahead and ask Panel 1 these questions now and, of course, please stop me or let me know if it is more appropriate to save these questions for Panel 3.

So, let's start with BOMA number 2, if you can put it on the screen, that would be great. In Part A we asked you to explain how the reference scenario, as described in your decarbonization study, was used to inform Hydro Ottawa's 2026 to 2030 forecast system capacity and you responded by providing, I call it, a multistep assessment process. Okay. You see it if you can show it on the screen there, right, the response. So you used the -- how I understand it, so you used the Hydro Ottawa Planning Forecast as described in section 9.1, Schedule 2-5-4 to assess your system's immediate needs and then you used the decarbonization study's reference scenario forecast to inform your IRRP forecast and you leveraged this IRRP forecast to align your investment decisions in these steps, or I guess this approach led you to the information shown in table 8 of Schedule 1-3-1. So far so good, right? I think I believe I was able to follow Part A answer. But your Part B answer kind of tripped me up and then I think I need some help here.

Let's see the Part B response here on the screen here. So, your response in both B1 and B2, I guess, in a nutshell is that the dual view scenario was not employed in the capacity needs assessment and therefore you were not able to answer. While I believe, and correct me if I'm wrong, I believe what you were saying is that since you already used the reference scenario forecast to inform your IRRP forecast, and you also leverage this IRRP forecast to align your investment, is probably a lot, a lot, of work to go back and use the different scenario, dual view scenario. Now, you have the revised IRRP forecast and then use this revised IRRP forecast to realign your investment decisions. Only then you can see the difference between the two runs and that's probably a lot, a lot, of work; is that correct?

M. FLORES: Good morning, this is Margaret Flores. So the reason why I wouldn't change the investments that were identified under the capacity program it's because we use the planning, the Hydro Ottawa Planning Forecast, to determine the system needs, and the Planning Forecast is based on the current system constraints as well as committed load. The IRRP forecast was used to determine the size of the station by leveraging the medium-term and the long-term forecast, also considering efficiencies in station construction. So, that will help us determine and to go with the maximum size for the 28 KV stations which is 100 MVA.

C. LI: Right. But you could do it, though? I mean, you could do it. It's just a lot of work because you have to redo the whole thing; do I understand it correctly?

M. FLORES: Well, it wouldn't really change the results because, like I said, the needs were identified using the Planning Forecast. Because of existing capacity constraints in those regions, as well as the committed loads that are coming in those specific locations.

C. LI: So, are you saying that it has zero impact or it has some impact?

M. FLORES: It wouldn't have an impact on the investments that were selected.

C. LI: Okay. But then I -- but in Part A that's not what you said in Part A, though. So are you saying that what you describe in Part A is not quite correct?

M. FLORES: Not really, because that's exactly what I'm explaining that we did in Part A. In Part A, I'm saying how we used the planning, the Hydro Ottawa Planning Forecast, and the IRRP forecast to help inform the investments, and that's exactly what we are saying in Part B. We wouldn't be able to do it, because it wouldn't adjust the projects that were selected for the capacity upgrade program.

C. LI: So when you -- how you arrive to -- but ultimately, in part A I was asking you, how do you come up with the numbers in table 8 in Schedule 1-31. So are you saying that even if you now are saying that the duel-fuel scenario is being used as a reference scenario, so the table 8 figures would not change at all; is that what you are telling me?

M. FLORES: Table 8 is the forecasted additional capacity based on the plan that we are proposing.

C. LI: Right.

M. FLORES: So the capacity that we are adding, it's by adding up the new capacity from the stations, so that wouldn't change. This is not reflective of the forecast. It's reflective of the additional capacity based on the project that we are proposing.

C. LI: Okay. So what will change, I'm sorry, then? I sort of follow, but I'm still very confused, to be honest. So if you -- if you go and say that now, okay, the duel-fuel scenario is actually more probable -- more probable scenario, and so what will change then?

So table 8 will not change, your DSP will not change. So what will change? What is the purpose of this decarbonization study then?

L. HEUFF: Hi, good morning, Mr. Li. So you will recall we were having this exchange as well, potentially. When we were describing the way that we used our planning forecast, it's to determine the investments that are required for capacity from the '26 to 2030 timeframe. The decarbonization study was leveraged as more as a mid- to long-term view to understand what we would need to be doing over a longer-term period and how to size our investments to ensure that we are efficiently deploying capital. Are you -- do you recall -- were you -- I'm not sure if you were listening to the proceeding yesterday and if you were following that exchange.

C. LI: Yeah.

L. HEUFF: So at the time of 2030, for instance, if there was a station that would require 75 MVA as a result of our '26 to 2030 load forecast, however, when you start employing the decarbonization scenarios, such as the reference scenario that we employed, it would indicate that we would be requiring 100 MVA in the mid- to long-term.

It would not be efficient for us to deploy capital to install a 75 MVA station, to then have to go back and redeploy additional capacity -- additional capital in order to increase the overall size of the station to 100 MVA just a few years later.

So we leverage the decarbonization forecast as an indicator of what types of growth we're going to see in the mid- to long-term to ensure that this capital deployment is efficient and that we are not having to go back and redeploy capital too soon.

Much of these assets are 40- to 50-year life assets, and so we don't want to end up with a large depreciation if we undersize the investments in the first place.

C. LI: So -- well, thank you. So what you are saying is, like, short-term, I guess, when I say short-term is this year term, 2026 to '30, is actually kind of irrelevant when it comes to what scenario you employ; is that correct?

L. HEUFF: Correct.

C. LI: It only matters, like, beyond that?

L. HEUFF: To an extent. It is really looking for more the mid- to long-term. It does help us understand how aligned we are and where our planning forecast aligns with the decarbonization scenarios as well. If we were to be looking and saw that our scenario was much higher than what the decarbonization scenarios were from the immediate needs, we would potentially have chosen a higher scenario. We aligned our scenario with the reference scenario, since that's the one that was closest aligned to our planning forecast.

C. LI: So there is some relevance then in terms of how you align your investment plan.

L. HEUFF: It's very much --

C. LI: Even for the [speaking over each other].

L. HEUFF: Yes, so the relevance --

C. LI: I missed what you said. It sort of cut off. I'm sorry, can you repeat, because I -- maybe it is my Internet. Can you repeat the last sentence you said?

L. HEUFF: Yes, sorry. The relevance is on our capital deployment efficiency, as I described previously, to ensure that the way that we are deploying capital is in an efficient manner.

C. LI: Right, okay. Okay, okay. Okay. I -- thank you. That's helpful. So let's move on to BOMA number 3 then. In BOMA number 3 in part B I asked you to explain the significant difference among the CAGR derived in reference 1, 2, and 4. By the way, CAGR, C-A-G-R, stands for compound annual growth rate. I just want to make sure it shows up correctly on the transcript.

Looking at the response you provided, I don't think you really answered my question. Like, I understand why the planning load forecast will always be higher than the revenue load forecast, because in my mind the planning load forecast would include extreme conditions such as extreme weather, or scenario, et cetera, and then, of course, the revenue forecast is most likely scenario. And, of course, there's a difference in terms of the absolute value of the forecast.

But what I don't get or would like you to explain is why the growth rate difference is so significant. Just for context, if you look at reference 1, the CAGR is 7 or 8 per cent, and then in reference 2 and 4, the CAGR are less than 1 per cent. So we are looking at a ratio of, like, 1 to 7. Can you help me out in -- and either elaborate now or you can undertake to elaborate your explanation in BOMA 3, part B -- like, I'm suggesting the following format -- actually, I'm asking for an undertaking, I think, is, can you produce the summary table that is, like, side-by-side, reference 1, 2, 4? I suggest that you can have some assumptions, key assumptions. You don't have to list every single assumption, maybe just the really key ones. Like, the housing style, population demographics, economics. I think those are probably shared. But most scenarios would probably use the same information. And then you can have, like, CDM or EDSM assumptions between the scenarios and the electrification activities between the scenarios. And to some extent I see some large load requests, data center, you know, I see -- I can understand that sometimes you have to make sure you are ready, but then the timeline when the load materialized, maybe that's a difference between the revenue forecast versus the scenario one, but list all the key assumptions and just help me -- I think that would be really helpful to see the deference between the different scenarios and explain the big growth rate difference.

Is this something that you can do?

L. HEUFF: So the majority of the details you are requesting would be better suited to be directed at panel 3.

C. LI: Okay.

L. HEUFF: So would you prefer to have an exchange potentially with panel 3 first to see if they can provide more clarity through discourse and through a conversation prior to taking the undertaking? Because I think a lot of what you are asking for they can potentially provide commentary on during their panel session.

C. LI: Sure, sure. I mean, I can do that, or, I mean, honestly, I don't really care. Like, if -- I think -- I think I explained it fairly clearly, what I am looking for. If you can provide that in writing, I am okay. Then I don't have to waste Panel 3's time.

It is up to you. I think I can go either way.

D. COBAN: I think it might be best to take this up with panel 3, to the extent that they can point you to information on the record that gives you what you are looking for, and if not, then we can deal with the undertaking as a follow-up.

C. LI: Okay. Sure. I am okay with that.

So -- you know what? I don't have any further questions, because some of my original questions had been covered yesterday already, so I don't need to repeat that, so that's all the questions I have. Thank you. Thank you very much.

M. MILLAR: Okay. Thank you very much, Mr. Li.

We are moving now to OEB Staff. We have a number of staff members asking questions, but we are going to begin with Ms. DeFazio.

EXAMINATION BY MS. DEFAZIO

M. DEFAZIO: Hello. Could you please pull up IR 1-STAFF-16? Thank you. In this IR, we asked about the OM&A growth factor. And the response explained that capacity is considered added when a new substation or BESS is energized, and feeders need not be constructed.

How does having a substation energized increase OM&A costs at Hydro Ottawa?

L. HEUFF: Sorry, Ms. DeFazio. I am just reviewing the referenced IR, and I am not seeing the correlation to the OM&A that you are specifically referring to. Can you just please help us find it on the record?

M. DEFAZIO: This is with respect to the growth factor, where you add capacity. The growth factor in the custom formula includes growth of customer numbers and growth of MVA. And the reference would be exhibit 1, table 17, where the growth factor is explained.

But we are just wondering, you know, how - or perhaps I should change this then, to panel 3?

D. COBAN: I think that would be best, Ms. DeFazio, since we have Panel 3 it listed here and your question really goes to the right framework.

M. DEFAZIO: Okay. Thank you. If we could go to Staff 231, please?

L. HEUFF: Apologies, Ms. DeFazio. It appears that staff ends at 221.

M. DEFAZIO: Sorry, to staff 31 - my mistake, sorry. So in this, we talk about corrective renewal and the asset inventory. I just have some high-level questions about how the asset inventory works. What kind of information is contained within the asset inventory on individual assets? For example, would it include installed or manufactured date?

L. HEUFF: Sorry, Ms. DeFazio, can you please clarify what you mean by "inventory"?

M. DEFAZIO: Your asset register or your asset, the date on all the assets that you use in your asset management.

L. HEUFF: Asset information repository?

M. DEFAZIO: That would be it.

L. HEUFF: Okay. And sorry, can you please repeat what it is that you are looking to understand?

M. DEFAZIO: What kind of information about individual assets is stored in that repository? - for example, the manufacture date or the installation date. But that will be included.

L. HEUFF: Yes, I can pass it on. Yes, so I can pass it over to my colleague, Ms. Flores, to provide a bit more context as to what information is provided.

M. FLORES: Yes. So the information that we have for assets will vary by asset type. For the majority of the distribution assets, we are storing that info in the GIS system, as well as the condition information. And then for stations, we have both GIS and another tool called PowerDB for testing information.

M. DEFAZIO: Thank you. Would physical location also be included, or installation location?

M. FLORES: That would be in the GIS system. You mean the GPS coordinates for --

M. DEFAZIO: Sure.

M. FLORES: -- where the asset is located? Yes.

M. DEFAZIO: Thank you. So in this question, we asked about specific -- let's consider a case where you have a piece of equipment that needs to be replaced under corrective renewal. It could be damaged plant, emergency renewal or critical renewal.

So a piece of equipment is replaced; say it was hit by a car or something. Would the asset registry then be updated?

M. FLORES: Yes, it would be updated with information for the new asset.

M. DEFAZIO: Excellent. How do you determine if the piece of equipment that was removed was scheduled to be replaced in the coming period?

M. FLORES: So we have a criteria that we apply for assets that were replaced on the critical renewal or emergency.

If the pole was already in the project list, it would be associated to the project.

M. DEFAZIO: Okay. How do you use equipment failure or replacement information from this program to feed into the asset management process? So if a piece of equipment fails and you replace it, does that get fed back into your asset management process somehow?

M. FLORES: Yes, that information was used when we updated the failure curves that we use, that we did with the consultant. We provided, like, the number of poles that had failed, as well as the poles that we still have in this system.

Now as it was stated in some cases, we knew the number of poles. But the detailed information on the age or the condition with the pole that actually failed wasn’t available at the time. But it is information that we are starting to collect as of 2023.

M. DEFAZIO: Okay. Thank you. Can we go to 2-STAFF-32, please, and go down to page 3, the response to Part B? And this shows table A.

Are you able to update this for 2024 actuals and a portion of 2025 actuals?

M. FLORES: We are able to provide 2024 actuals; is that sufficient?

M. DEFAZIO: Yes, thank you.

M. MILLAR: We will mark that as JT 2.1.

UNDERTAKING JT 2.1: To update failure curves for 2024 actuals and a portion of 2025 actuals

M. DEFAZIO: Could we go to 2-STAFF-37, please, and down to page 3. It talks about vault renewal:

The forecast spending increases essentially to manage the growing number of vault equipment owned by Hydro Ottawa that have reached their end of life is what it says in the exhibit. I would like to clarify. These vaults, are they owned by customers, but the electrical equipment is owned by Hydro Ottawa? Is that correct?

M. FLORES: It is a mix. The main driver is to replace aging vault transformers. Hydro Ottawa would own those transformers. There are some legacy vaults where customers will own the switchgear, as well.

M. DEFAZIO: Okay. And some utilities referred to rooms under the sidewalk and in the roadway as vaults, and some refer to them as rooms in customer buildings.

Can you clarify which vaults these are?

M. FLORES: These would be rooms in customer buildings.

M. DEFAZIO: Okay. Can you describe the configuration of the distribution system, that the equipment in these vaults are used in, for example, is it a radio system, a dual radio, a primary loop?

M. FLORES: Vaults are mostly in our 13KV system and there might be a combination of them, but mostly loop or dual radio.

M. DEFAZIO: Okay. What's the consequence of a failure of a transformer in this system?

M. FLORES: It depends. In some cases it will be all the customers connected to that transformer.

M. DEFAZIO: Thank you.

M. FLORES: There might be higher implications if the switch gear fails which impact all the customers on that feeder.

M. DEFAZIO: Thank you. And what types of customers are supplied by the system?

M. FLORES: It would vary, so commercial and residential.

M. DEFAZIO: Okay. Is this 13KV system with the vaults, is it in a particular area of town or is it all over?

M. FLORES: It's mostly in the downtown area.

M. DEFAZIO: If we can go to Exhibit 2, Tab 5, section 5 and page 65, please. So, here table 19 shows what was planned to be replaced in 2021 to '25 and what is actually forecast to be replaced. And under the vault transformers we see that there was a significant reduction in the amount of vault transformers that were replaced in the historic period. Can you explain why the replacements were reduced?

L. HEUFF: Hi, good morning. As a result of unexpected events, such as the derecho, and inflationary impacts that we saw throughout the '21 to present period we had to prioritize various programs, as you've seen, throughout the forecasted to forecasting the historical spending throughout Schedule 255. One of such programs, it was de-prioritized through that review was the vault transformer renewal program.

M. DEFAZIO: Thank you. Can we go out now down to page 75, table 23? So, here it shows that the amount of transformers planned to be replaced in the forecast period is 90, which is less than the amount, the -- so if we had the 18 from '21 to '25 and the 90 from' 26 to '30 the amount is still less than the total amount that was forecast originally for '21 to '25. Can you explain how you determined the new number of vaults that needed to be replaced in total; compared to what was projected last time? Sorry, transformers.

M. FLORES: Yes, I would like to point you to Schedule 257, Section 4.3, page 83 and just going down to find the vault section. Page 95. 95. So, in this section we show the typical useful life for the vault transformers in Figure 53, and in Figure 54 we show the condition and the degradation from 2024 to 2040. Vaults were assessed as part of the overall underground distribution asset renewal strategy. Applying the criteria evaluation to select the alternative for the entire asset class.

M. DEFAZIO: Can you scroll down the page just a little so we can see the colour legend? Okay. So this is Reached or Exceed TUL. Have you done a condition assessment on those transformers?

M. FLORES: Yes, we do. We do have an updated condition assessments. As of 2024 we have increased the parameters that are captured for the vault transformer health index calculation.

M. DEFAZIO: Could you provide that, please?

M. FLORES: The formula or the parameters that go into the vault?

M. DEFAZIO: The results, just similar to this instead of TUL or condition of the vaults. Oh, you may have done that in...

M. FLORES: Yeah, so we're showing the condition in Figure 56. 54. Yeah, sorry. I was looking at the wrong figure. Figure 54 is the condition profile of vault transformers.

M. DEFAZIO: Thank you. Could we go, please, to 2-STAFF-38? And down to page 2, the response B(i). So, here it is -- Hydro Ottawa explains it does not rank program level capital expenditures against one another on a dollar spent per risk dollar reduced basis. At the project level capital expenditures are ranked on a dollar spent per dollar reduced basis, but that's done annually. Why does Hydro Ottawa not compare risk dollar reduce between programs or between programs and projects?

J. GILLIS: Sorry, can you repeat the question? Why does Hydro Ottawa not compare...?

M. DEFAZIO: So you don't compare the risk dollar reduced between programs, you say you only compare it between projects. Why don't you compare it between programs or between programs and projects?

J. GILLIS: So, the way that we use Copperleaf PA is to evaluate the risk on a per asset basis which is then summed up to a project level, that project level information then feeds into our Copperleaf portfolio analysis, which is done on the project basis for our system renewal and system service investments at the annual planning level. And your question is why do we do it in that format?

M. DEFAZIO: Well, how would you compare, then, the system service versus the system renewal risk dollar reduced when you are doing your planning and setting those levels?

J. GILLIS: Yes. So, the way that we do that is on an annual basis, and that's done through the project level optimization through Copperleaf on the annual basis. And so, it's not a ranking of the projects by projects on the risk dollar per expenditure level. It's on the overall value framework.

M. DEFAZIO: So how do you determine how much money would go into those two programs; system service versus system renewal?

L. HEUFF: So, Ms. DeFazio, we discussed this a little bit yesterday. So each area is done a little bit differently. So, under the system renewal category, as Ms. Flores described yesterday, each of the projects are ranked -- or, sorry, each of the investment levels are determined by the subject-matter experts. I think possibly it was actually me providing this testimony. Apologies. So there -- that we would use Copperleaf PA to first begin to understand how many investment level -- or what the investment levels were required by asset category, and those would be formed into a program-level investment. And they ultimately through -- as you can see through Section 257, those are where we produced the material investment plans by asset category.

Under the system service it's done differently, depending on which area you are looking at. When you look at the capacity section, we were just having a discussion just previous to this section on how we determine what capacity investments are required, and so those ones come together based off of the load forecasting and the understanding of the needs, both at the -- within the regional levels, essentially, so with each voltage level within the system, and then other areas such as distribution enhancement. We had a discussion yesterday as well on how the resilience program was determined.

So each one of those programs are done individually, and then they are -- we did the evaluations against the different investment levels, and those evaluations are provided in the material investment plans.

At that point in time, we create the budget levels for each of the programs, and once those have been approved through this proceeding, those will be what we target on an annual basis whenever we are determining which projects to undertake.

So then, at that point in time, we would follow the process that was just described by Ms. Gillis. So if you take the pole renewal program, for instance, if we have put through a target and we determine under the program level that we will replace 400 poles per year, then we would look through the system to determine which assets are at higher -- highest risk; group them together into projects; and then use the values framing -- the value framework to score each individual project to determine which level of -- or which projects have the highest investment level, and then we would replace those projects on a ranked basis.

And so it's at that point in time that you would see that the cost basis comes into play, is whenever we are doing the individual project values on an annual basis.

M. DEFAZIO: Okay, thank you. Could we just take a step, I guess, one level higher? If you were looking to set the values, how much you were going to send in system renewal versus how much you were going to spend in system service? Is that something that -- that's something that is set prior to your process? Would that be correct?

L. HEUFF: So not exactly. I would take you to -- just a second. So under Exhibit 1, tab 2, Schedule 3, Attachment A, you will note -- that is the memo that was provided when we were originally setting our '24 to 2030 budgets and priorities. So as was described in 2 -- I believe it is 2-SEC-41, Part A -- so under part A, you will note that the first stage of the needs analysis actually resulted in a 2 million-dollar expenditure over five years, so following the issuance of the corporate memo, all teams went back and at an individual level throughout the company determined what their needs were, and then at that point -- and so those were all developed at a program level, which would be equivalent to what would be in each one of our material investment plans, which are the capital expenditure plans that are outlined in Sections 256 through 259. From there, the Board reset or asked for everyone to do a reprioritization as a result of affordability and set a new capital target, as indicated in this IR at $1.2 billion. From there, each one of the material investment plans were reviewed by the individual program owners, and they were reduced in a manner that was considered to be a more cost-effective plan, and where they would be requested to balance risk overall with the overall capital needs.

And so you will see in Part A -- Table A, apologies, it was the initial capital needs budget, and then Table B shows the revised needs down to 2, Table 2 -- or under Table B, apologies.

M. DEFAZIO: Okay. Thank you.

Could we please return to 2-STAFF-38 and go down to the response for Part B3, so it must be the next page -- yes. So here we say -- it's:

“Hydro Ottawa measures its ability to achieve program level risk mitigation through the performance outcomes, and you don't evaluate the risk mitigation at the individual project level, as the performance is measured at the program level.” [As read]

So how does Hydro Ottawa map its asset management process to the KPIs? I'm still a little confused by this program level and project level stuff. So to clarify, you calculate risk reduction at the project level, but you measure performance outcome at the program level; is that correct?

S. HAWTHORNE: That's correct.

M. DEFAZIO: So how do you evaluate if an individual project has had any impact for the desired outcome?

L. HEUFF: So we do that in a couple of ways. So as you are noting on the performance outcomes, I would actually point you to Section 253 -- sorry, Schedule 253, under Section 6, starting on page 70, and specifically on page 71, Table 27, the KPI names and categories.

So at a program level, these are the individual KPIs that we monitor to ensure effective implementation of each one of the programs. And at the project level, we would have the value framework on system service and system renewal investment, so the Copperleaf scoring and the individual scoring of each one of the projects would also be evaluated through Copperleaf, and that would be where we would determine the individual value of each project.

So there are two different ways of looking at it: One is the effectiveness of the project and how much value is being provided on a risk/cost basis, which was, I believe, the original part of your question. And the second one around program implementation, and to ensure effective implementation of our programs, we measure that ability -- or we measure the program implementation effectiveness through the KPIs that are described in Table 27.

M. DEFAZIO: Okay. Thank you.

Can we go to Staff 255, please. If we go down to page 6 and the response to part E. So here Hydro Ottawa states again that:

“The predictive analysis is used to inform the system renewal asset replacement strategies.” [As read]

How does the predictive analysis or your asset management which would be system renewal account for assets that are replaced under other programs such as system access and system service?

M. FLORES: So assets that are replaced in other programs are not necessarily degraded assets, they are assets that have a high risk to our system. They would be very specific based on the customer or the location.

M. DEFAZIO: Okay. So if you were replacing assets as part of another program, say you doing a road-widening, and a portion of those assets were high-risk assets.

You would be replacing in effect more high-risk assets because of the ones identified through the system renewal, plus the ones under the road widening? So your total would include both?

M. FLORES: It would, yes. It would include both at the end of the year when we identify that that is the case. But typically, if there are assets that have reached their useful life or are in a degraded condition, that would be informed to the asset planning team, and the project list will be adjusted accordingly.

M. DEFAZIO: Thank you. Could we please go to 2-STAFF-41, the response to Part A which is on page 2? And in here, it says in the third paragraph:

“Hydro Ottawa further reports the annual probability of high wind speeds above 130 kilometres per hour as 2.9 per cent and, for 180 kilometres per hour, 1.25 per cent.”

If we could now go to where this is from, which is exhibit 2, part 3 – sorry, exhibit 2, tab 5, section 4. And there is an attachment B. And I want to go down to page 16, please. Yes.

So here we see table 3, which talks about probabilities of wind threshold. Now if you scroll up to the page just above it, in that last paragraph it talks about tornadoes having two scenarios: the likelihood of a single point within Hydro Ottawa's service area being struck by a tornado, and No. 2, the likelihood of a tornado occurring anywhere within the service area.

When it comes to the wind speeds and the percentages we just mentioned for the 130 and the 180, what scenario was looked at? Was it the likelihood of a single point in the service area experiencing that wind speed, or the one speed is occurring somewhere within the service area?

M. FLORES: It would be somewhere within the service territory.

M. DEFAZIO: Okay. So would the likelihood of it occurring somewhere within the service area be a higher likelihood or a lower likelihood of it occurring at, if you were to evaluate a specific point in the service area?

M. FLORES: Sorry, to clarify: this percentage is not just for tornadoes. It's for any weather event, where the wind speed is higher than 130 kilometres or 180 kilometres.

M. DEFAZIO: Yes. So if the wind in a - I would just like to clarify: If I was to take a specific area and look at the likelihood of the wind exceeding 150 kilometres in that area, but a specific point, versus 150 happening anywhere in the area, which one would have the higher likelihood?

M. FLORES: I don’t believe that was measured that way in the study, so I wouldn't be able to tell you.

M. DEFAZIO: Okay, thank you. Could we go back to the IR, please? And that is IR 2-STAFF-41, and part C, the response to part C. There is a table. This table goes through, I am presuming, to the end of 2023.

Could we have the values for 2024, updated in this table, please?

M. FLORES: Yes, we could.

M. DEFAZIO: Thank you.

M. MILLAR: That is JT 2.2.

UNDERTAKING JT 2.2: Provide updated table values for 2024 in response to part C of IR 2-STAFF-41

M. DEFAZIO: Could we go to 2-STAFF-43, please? So this IR talks a lot about typical useful lives, or TUL. When Hydro Ottawa calculates the TUL, does it consider all causes of retirement, or - which would include things such as vehicle contacts, road widening, voltage programs, et cetera? Or would it include only those that were from -- I don't know, let's say, natural asset degradation.

M. FLORES: Mainly from natural asset degradation.

M. DEFAZIO: Thank you. If we go to the response to Part A, please, the last – sorry, the first paragraph, the second-last line, says:

“TUL is defined for an entire asset type, but condition is determined at a single asset level."

Now if we can scroll down to the response to Part B, please? Hydro Ottawa says:

“Typical useful life is one of the factors used in the condition analysis.”

Is typical useful life used as a factor in the conditional – sorry, in the condition assets for all assets? Or just a subset of assets?

M. FLORES: So maybe just to clarify: Age is a parameter that is used in the condition calculation. Is that what you mean?

M. DEFAZIO: Sure. So you are not using – typical use, okay. So you are using age. And is age used as a parameter for all assets, or a subset of assets?

M. FLORES: It is used in most assets, yes. And we mostly enhancements –-

M. DEFAZIO: If you have a –-

M. FLORES: Sorry. I just wanted to add that it is a condition that - a parameter in the condition calculation. As part of the health index enhancements, we have reduced the weighting on age for our most recent asset-condition framework.

M. DEFAZIO: Thank you. Are there any assets that you can readily assess their condition?

M. FLORES: The condition has been assessed, and we have a summary of that result in the schedule 257 for each of the individual assets.

M. DEFAZIO: Sorry, let me explain that differently. If you go in and inspect an asset and you can, through whatever kind of inspection and testing you do, you are able to determine what conditions the asset is in to feed into your asset condition assessment, why would you still include age, if you can readily do an evaluation?

M. FLORES: Because there's a crucial component of the health index calculation still, so we would include age. But it's not the only parameter that defines the condition of the asset. It would be adjusted based on the other parameters that are added to the calculation.

M. DEFAZIO: Okay, thank you. I just want to make sure we understand your approach to asset maintenance for assets that have reached or exceeded their typical useful life. And (b)(i) on the screen here says:

“Hydro Ottawa is not avoiding investing in assets that have reached or exceeded TUL regardless of their condition assessment…”

And then if we go down to (c), it states:

“Hydro Ottawa has concluded that more frequent inspections are a better investment than immediate rehabilitation or maintenance of assets at or beyond their TUL, but in adequate condition.”

Does this mean that Hydro Ottawa considers inspections to be investments in the assets?

M. FLORES: No, not necessarily.

M. DEFAZIO: So on one hand you are saying you are not avoiding investing in assets that have reached or exceeded their end of life and in the other you state that frequent inspections are more appropriate than doing rehabilitation or maintenance on the asset. What are the cases where you would do life-extending maintenance or rehabilitation or repairs on assets; can you give examples of that?

M. FLORES: So, our asset strategy prioritizes risk mitigation, maintaining the overall performance of assets and portfolio optimization. Inspection and maintenance is a component to maintaining the overall performance of the assets. In this case, based on the selected capital plan we have determined that we would need to enhance the pole renewal, the pole inspection, I mean. So, there would be selected degraded assets that would be inspected at an increased rate. That's an example. Another example would be station assets where we are enhancing the monitoring of those equipments, as well as inspection for some of the degraded assets to help us come up with reactive maintenance to be able to keep those assets in service for longer, since we are not replacing all degraded assets.

M. DEFAZIO: Okay. So, we talked about poles and cables yesterday where Hydro Ottawa isn't doing a rehabilitative investments in TUL poles and/or cable injection was found to not be a suitable life extension methodology for underground cables. If you are inspecting assets more frequently, what kind of maintenance or rehab, can you give examples of anything where you do do physical maintenance to an asset, that's TUL, to keep it going?

M. FLORES: So an example would be station transformers.

M. DEFAZIO: Okay. And what do you do for station transformers?

M. FLORES: So, in some cases as a result of the inspection or testing that is performed we will replace a transformer bushings at the station level or some other components of the transformer to be able to keep that asset for longer.

M. DEFAZIO: Thank you. Can you think of any more examples?

M. FLORES: In the case of poles and cables, although we are not, right now, suggesting any rehabilitation, we are capturing more data than in the future will inform maybe potential components that will need to be replaced like in the case of poles. We are suggesting to implement a drone inspection which would allow us to capture more detailed component information. In the case of cable, we're enhancing the testing that we're doing so that we could identify, like, other degradation aspects of the cable, as well as components that will need to be replaced.

M. DEFAZIO: Okay, thank you. Can we please go to STAFF-251? If we go to page 3 of the IR, table A. Would you be able to update this to include data for 2024 and 2025, to date, please?

M. FLORES: Yes, we could include 2024 numbers but not 2025.

M. DEFAZIO: Okay, thank you.

M. MILLAR: That is JT 2.3.

UNDERTAKING NO. JT 2.3: Update Staff-251, IR page 3, table A to include 2024 numbers

M. DEFAZIO: With regards to cause code 6, which is if we scroll down, just a little bit please, that is adverse weather. Are you able to break out the cause code by adverse weather interruptions that involved a tree contact as a secondary cause, and those that did not?

M. FLORES: I believe that is based on the new definition for secondary cause codes. We would only be able to do it for 2024, not for the historical years.

M. DEFAZIO: If you could do that for '24 that would be appreciated. Thank you.

M. MILLAR: That is JT 2.4

L. HEUFF: Apologies, Ms. DeFazio, just to confirm, and so that it is clear on the record, we will reproduce table A for 2024 explicitly as stated except for under the case of 6, cause code 6 adverse weather, we will also include a secondary cause code of tree contact.

UNDERTAKING NO. JT2.4: Reproduce table A for 2024 explicitly as stated. For cause code 6, adverse weather, include secondary cause code of tree contact

M. DEFAZIO: Yes, thank you. Could we go, please, to 2-STAFF-52? And in the answer in this Hydro Ottawa explains that:

“[...]Restoration times for some of these outages were prolonged as extra time was required to make the outages, sorry, the outage location safe while coordinating with the City of Ottawa and emergency services in addition to performing forced switching and sexualizing during fire related emergencies.” [As read.]

What changed in 2022 that increased the time to make locations safe while coordinating with the City of Ottawa and emergency services compared to other years?

M. FLORES: That would be related to specific outages, so it's the duration under scheduled outages is very specific to the nature of the incident, the location and the configuration of the system, so it could vary year over year. We make our best efforts to reduce the average length, but in some cases for the reasons specified in that answer, the outage needs to be extended.

M. DEFAZIO: So 2022 was just an unlucky year?

M. FLORES: I wouldn't have the information on the specific asset that, or the specific outage, but it resulted in a higher number.

M. DEFAZIO: Thank you. Can we go to 2-STAFF-54, please? So, in this question Hydro Ottawa, we -- the preamble references a quote from the exhibit that explains 5 items that are impacting SAIDI. When we look at the response, if we go down to the question:

“Hydro Ottawa proposes capital investments and distribution enhancements to further reduce outage restorations time." [As read.]

It seems like the only item that the response addresses is the third bullet of the 5 reasons listed above. Is there any other projects identified under distribution enhancements that would address the other 4 reasons?

J. GILLIS: Yes, so the distribution enhancements capital program encompasses a number of different subprograms underneath, another one of which is the resilience program, which would help impact/reduce tree contacts and foreign interference, as well as reduce the impact from adverse weather events as well. So it is not just the observability program underneath distribution enhancements. And if we want to go and take a look at Schedule 258, section 3, right on page 66. And you can see right at the top of the page that it lists the budget programs as distribution system reliability, distribution enhancements, distribution system observability, as well as distribution system resilience. So it's all those programs under -- encompassed underneath distribution enhancements that would capture all 5 of those different components as stated.

M. DEFAZIO: Thank you. Could we go to IR 2-Staff-59, please? And down to page 5. So I'd like to ask some questions to better understand this Figure A sample pool intervention value. At the bottom of page 4, which is just above page -- this page here, it says:

“Total intervention value was calculated at 674.92 value units." [As read]

What is the unit of measure? And that's the measure of unit on the vertical scale of the graph, the 674.92? Is it dollars or thousands of dollars? Can you scroll back to the graph?

M. FLORES: It is the Copperleaf value number that would allow us to compare assets.

M. DEFAZIO: So it's not related to -- it's not directly relatable to a real-world value like a -- like a dollar? It's a -- it's its own scale?

M. FLORES: It's translated to dollars, but that would allow us to complete the calculation, which is reliability risk plus financial risk plus safety risk, environmental risk, and replacement costs.

M. DEFAZIO: So if we look at a replacement cost of 26.4, is that $26,400?

M. FLORES: Not necessarily. It's the value score of the project.

M. DEFAZIO: Okay, thank you.

We see a reliability risk here of 671.3, and I understand that this is an example. Would the reliability risk for a new pole and an old pole be the same in the same spot?

M. FLORES: Sorry, just to correct, before, you were asking the 26.4. That's a replacement cost for that single pole.

M. DEFAZIO: Okay, so 26.4 thousand dollars [sic].

M. FLORES: Thousands, yes. That's correct.

M. DEFAZIO: Okay, thank you. Okay. Would that be for a planned or an unplanned replacement, or are they assumed to be the same?

M. DEFAZIO: This is just the value of the asset itself. It doesn't necessarily mean that it's replaced -- oh, you mean for the cost of the replace cost?

M. DEFAZIO: Yes.

M. FLORES: That would be in a planned fashion.

M. DEFAZIO: Thank you. I don't want you to pull up this reference unless we need to, but in 2-SEC-40 it states:

“In Copperleaf PA, risk is calculated as risk equals consequence times likelihood.” [As read]

Is risk the same thing -- sorry, so risk being consequence times likelihood, is likelihood the same thing as probability in this context?

M. FLORES: Yes.

M. DEFAZIO: Thank you.

So, again, you don't need to pull this up unless we need to, but in response to 2-Staff-62 it stated that:

“Poor condition poles have a probability of failure of 7 per cent a year.” [As read]

So the consequence for this pole, if the reliability -- sorry, let me get back here. If the reliability is -- 671.3 is the reliability risk and risk is consequence times probability, would the consequence be 673 divided by 7 per cent, which brings us to about 9 million?

M. FLORES: I don't believe so. The percentage that we got was looking at the probability of failure curve, and the assets that we have in degraded state -- or the poles that we have in degraded state.

The reliability risk value here is based on the calculation of multiple parameters that go into that, which include the probability and consequence.

M. DEFAZIO: Okay, so we couldn't use the 7 per cent failure for the replacement costs of the -- never mind.

Okay. If we look at distribution transformers, you would have a similar analysis for distribution transformers as well, I presume, right?

M. FLORES: Yes, we do.

M. DEFAZIO: Okay. And evidence throughout the application we've heard that distribution transformer costs have gone up significantly in recent years.

What -- has that value been used to update your intervention values, or how often would you update the equipment costs when it comes to calculating your intervention values?

M. FLORES: Yes. So we have used the updated numbers for the distribution transformers.

M. DEFAZIO: Okay. Thank you. So can we go to 2-STAFF-62, please. And the response for Part A, this goes through and calculates the failure rate for poles assessed in very poor condition, and if you can scroll down, please, so we can see the formulas. So here we have the probability of failure, and there is a lambda value for very poor condition poles. Can you provide the lambda value for poor condition poles, please?

M. FLORES: Yes, I don't have it offhand, but we do have that.

M. MILLAR: That will be JT2.5.

UNDERTAKING NO. JT2.5: Provide the lambda value

**for poor condition poles**

M. DEFAZIO: Thank you. And when you develop the lambda values, do you include all reasons for replacement of the pole or just the natural failure, for example, excluding things like road-widenings and damage to plant?

M. FLORES: The lambda value is based on our probability of failure curve, which is using information from the historical degraded assets.

M. DEFAZIO: Thank you. How does Hydro Ottawa determine that or define a pole as failed? Does it have to, you know, visibly fall or break, or is there different criteria?

M. FLORES: Sorry, can you repeat the question, please?

M. DEFAZIO: How do you -- what's your definition of a failed pole?

M. FLORES: A pole with less than a 30 per cent health index will be considered a very poor pole, a pole in very poor condition.

M. DEFAZIO: Okay. And how many pole failures did Hydro Ottawa have in 2024?

M. FLORES: No, all pole failures don't necessarily result in an outage. For poles that -- pole failures that result in an outage, that would be listed under Exhibit 253, section 4.5, and we have a table there. The number of poles that resulted in an outage -- let me just find the right table. So it's table 26 on page 56: There are other poles that are also considered in a failed state, but that not necessarily cause an outage. The definition for that could be found in 257. Give me just a second to find it - page 151.

That will have the criteria that we use for emergency renewal and all the assets that get replaced under that.

M. DEFAZIO: Okay. And do you have a number for this? Because your - we calculate a probability of failure, and we know how many poles are in what condition. Do you see that number of failure, that – like, how do you --

M. FLORES: Well, historically, we have seen an average, like, around a hundred poles replaced under the critical renewal and emergency renewal.

M. DEFAZIO: Thank you. Can we go to 2-STAFF-77 please? So here, we are talking about the bulk metering buildings that are converted to multiple customer metering systems or suite metering. And part B of the IR in the answer, it talks about how the forecast was done. And the forecast was done using historical trending to forecast the test-year capital amounts.

Would it be reasonable to conclude that we could therefore use historical trending to forecast the volumes, if we are using the forecast to – sorry, if we are using trending to forecast the dollars?

S. HAWTHORNE: So our forecasting approach for suite metering was using historical trending of gross capital expenditures. So we used financial information as a proxy for volumes. Given that projects can extend between fiscal years, I can't comment as to whether or not that will, one to one, translate to volumes in any given year.

M. DEFAZIO: So did you use in-service additions or expenditures?

S. HAWTHORNE: Expenditures, gross capital expenditures.

M. DEFAZIO: Gross capital expenditures. Are you seeing explosive price increases or decreases on suite metering equipment costs?

S. HAWTHORNE: One moment. I would just like to confer.

We have seen general cost increases but, unfortunately, I do not have further specifics at this time.

M. DEFAZIO: Okay, thank you. As a general statement, would converting the metering of these buildings from bulk metering to individual customer metering result in more or less load being consumed by the property? Or the same?

K. LELLIOTT: Hello, this is Kris Lelliott. We don't have specifics on our available evidence to show you the consumption difference between the bulk metering and an individually suited meter, i.e., building.

M. DEFAZIO: What, like a before and after?

K. LELLIOTT: I don't have any evidence that has been filed to show that.

M. DEFAZIO: I understand you don't have any evidence, which is why I am asking.

Would you expect the load to increase if people got their own meters?

K. LELLIOTT: I am not sure how I can answer something that would be what my thought would be, but I can take a crack at it if you would like.

M. DEFAZIO: Sure, thank you.

K. LELLIOTT: I would say if you received your individual bill, you would be more visible to your consumption and that might change your habits.

M. DEFAZIO: Thank you. Would converting the metering of these buildings result in more or less OM&A expense for Hydro Ottawa?

K. LELLIOTT: Let me confer, please.

D. COBAN: And Ms. DeFazio, just a clarification that when it comes to OM&A, the witnesses on this panel can really only speak to a subset of OM&A. If you are looking at a broader understanding of OM&A costs as they relate to serving these customers, maybe that's a question for panel 3.

M. DEFAZIO: Okay. Thank you, I will mark that.

I am good to go to the next question? Or are you still conferring?

K. LELLIOTT: No, you are good to go to the next question. Thank you.

M. DEFAZIO: Okay, thank you. If we could go to Staff 287, please? Okay. This question, we asked for a bunch of information on the CCRA contracts and invoices which you provided. And we attempted to reconcile the invoices provided in 2-STAFF-87 with the historic values in 2-OEB, chapter 2 appendices, tab 2AA. And we couldn't get close. I don't know what we are missing.

I was wondering, could you maybe explain why the invoices didn't match with 2AA, or perhaps file something that would link the invoices to 2AA?

L. HEUFF: I believe the reconciliation question, Ms. DeFazio, would likely be better suited for Panel 2.

M. DEFAZIO: Okay.

L. HEUFF: If you have questions on the specifics of any one of the individual CCRAs, what cost basis was provided within them, what the projects were related to, panel 1 would be able to support. However, anything to do with reconciliation of costs would be better suited for panel 2.

M. DEFAZIO: Okay. I will give this one just a shot here and, if not, I will ask it to panel 2: Do you make payments to Hydro One through a method other than through invoice, perhaps at the start of the project of the CCRA? Or do you always wait for invoices? Or is that a panel 2 question?

K. LELLIOTT: We typically provide payment to Hydro One via invoice. Yes.

M. DEFAZIO: Thank you. I think this is a good time for our scheduled break?

M. MILLAR: Okay. Great. We are pretty much right on time, so let's break until 11:15.

--- Recessed at 11:00 a.m.

--- On resuming at 11:20 a.m.

M. MILLAR: Go ahead, Ms. Coban.

D. COBAN: Perfect. So, we received a letter from Environmental Defence, which was filed with the Board on September 10, 2025 that set out a number of questions that we have agreed to answer to in writing. So if we could enter that as an exhibit, and give it an undertaking?

MR. MYERS: The exhibit is KT2.1, that's the Environmental Defence letter dated September 10 and the undertaking to respond to those questions is JT2.6.

EXHIBIT KT2.1: Environmental Defence letter dated September 10, 2025

UNDERTAKING JT2.6: Undertaking to respond to Environmental Defence's questions in the letter dated September 10, 2025

D. COBAN: Excellent, thank you. And then on September 19 we received a letter from DRC's counsel, also providing a number of questions that we will answer in writing if we could give that an exhibit and an undertaking, please?

M. MILLAR: Yes, that will be KT2.2 for the letter and JT2.7 for the responses.

EXHIBIT KT2.2: DRC letter dated September 19, 2025

UNDERTAKING JT2.7: Undertaking to respond to DRC's questions in the letter dated September 19, 2025

D. COBAN: Thank you.

M. MILLAR: And that's all of them?

D. COBAN: Yes, that's all.

M. MILLAR: Okay, great. Why don't we go back to our regularly scheduled questioning. And I'll turn it back to, Ms. DeFazio.

M. DEFAZIO: Thank you. Could we please go to

IR 2-STAFF-95? And down to the third page to see table A. And so, here we see overhead conductor failure classifications, and there is a number of failures for overhead conductor. Could you please explain the failure mode for the actual conductor itself?

M. FLORES: Yeah, it would be mainly like the cable snapping. I don't have the details on the 16 that you're mentioning for 2023, but that would be typically what would happen for overhead conductors.

M. DEFAZIO: And why would the cable snap; how can you prevent those?

M. FLORES: Overhead conductors at this time are replaced at the same time as the poles, so it's part of our pole renewal program. In some cases we would have to, if it snaps, we might have to replace a section and we would capture any issues with overhead conductors through our IR scanning or our drone inspection that we are proposing for our next rate application.

M. DEFAZIO: Okay. Can you explain to me what you mean by, just for those people on the case who don't understand the terminology, I guess. So, what do you men when an overhead conductor snaps, like, does it break; does it shrink?

M. FLORES: Yeah, it would break.

M. DEFAZIO: Thank you. Can we please go to 2-STAFF-97? And down to part C. So, here we are discussing overhead pole mounted transformers. Does Hydro Ottawa proactively replace pole transformers or operate them as run to failure?

M. FLORES: We replace overhead transformer as part of the pole renewal program since both assets have a similar TUL.

M. DEFAZIO: Thank you. Could we go down to 2-STAFF-102, please? Down to the answers. The answers state that, if we go down just a little bit more, I guess to part C, the probability of failure of those in poor condition at 6.6 percent, and probability of failure of those in very poor condition at 8.6 percent. Do you know how many pad mount distribution transformers failed in 2024 or recent years?

M. FLORES: Give me a second. I believe we have an IR with that information. So it would be the same table that I showed before in 253. Give me a second to find the page number. 251, apologies, page 56. If you go down a little bit and take a look.

M. DEFAZIO: Yeah, okay.

M. FLORES: So that will have the number of failures that we've seen historically.

M. DEFAZIO: 2024. How do you define a failure of a transformer? Oh, sorry, we looked at that table earlier.

M. FLORES: Yes, that would be on 257.

M. DEFAZIO: Yeah. So, these failures, they would be not damage to plant, like a car accident. These would be transformers that upon inspection or some other notification failed?

M. FLORES: That's correct. These numbers reflect the equipment failure that counts in average and they are the equipment failure category. So if there was an outage as a result of a car hitting a transformer that would be under foreign inference.

M. DEFAZIO: Okay. And there is a fairly large -- well, sorry. There is a number here of pad mounted transformers, we are looking at 92, 49, 41. Could we, please, go to SEC-44A? Sorry, it's 244. Yes. And down to the question 4A. Sorry, and it's Excel sheet. So, here if we look for underground transformer, we see this is for 2024, so this is -- when would this have been produced, like at the beginning of '24, the end of '24?

M. FLORES: It would have been produced at the beginning of 2024 with data collected after the end of 2023.

M. DEFAZIO: Okay. I know it's not the same year, '24 wasn't shown on that failure table, but here under asset condition, we have underground distribution transformers in very poor condition, we have 1, and in poor condition, we have 38. If we look at the probability of failure of those, you know, you were seeing around in the numbers 30s and 40 failures a year, that's more that are assessed in very poor and poor condition. Could you explain that anomaly or how your model supports this?

M. FLORES: Yes, in order to consider the, that number, we also include assets that -- or underground transformers that are in poor condition and some in fair, because we have seen a high number of reactive replacement of some of those transformers. That's why we expanded it beyond the very poor number.

M. DEFAZIO: Okay. Well, can you provide the probability of failure for fair condition transformers?

M. FLORES: Yes, we can provide that.

M. MILLAR: That's JT2.8.

UNDERTAKING JT 2.8: Provide failure probability for fair condition transformers

M. DEFAZIO: Could we please pull up Exhibit 2, tab 5, Section 8, please. And page 18.

Okay. So here you're talking about the new Kanata North MTS, a proposed station, 230 kV to 28 kV, 100 MVA, eight new feeders. I am just looking for some additional information on the proposed station. For example, the number of station transformers, would it be two? Or one?

J. GILLIS: Yes, that's correct. Two transformers.

M. DEFAZIO: Okay. And what configuration would the station be [inaudible] dozen, a dual-radial, et cetera?

J. GILLIS: Our standard configuration, I believe, is a dozen, which is a dual-ended spot network configuration.

M. DEFAZIO: Okay. And how will the egress from the station be constructed? Would it be overhead or underground?

J. GILLIS: Just let me confer for one moment.

S. HAWTHORNE: Hi, there, just to provide one clarification on the configuration of the new Kanata North station. It's actually a main tie main configuration, and with regards to the egress, the cables exit the substation typically underground out of the switch gear via a duct bank. As for outside of the station fence, particular egress can vary, depending on the feeder and its location --

J. GILLIS: Thank you.

S. HAWTHORNE: -- either overhead or underground, excuse me.

M. DEFAZIO: Thank you. Can we go to the next page, please, and look at the figure? Okay. So the grey area, it's kind of got a white line across it, that would be the current LTR; is that correct?

J. GILLIS: What's shown under the grey shaded area would be the current LTR, plus the additional LTR once the Kanata North is energized, and you can see that jump in 2028.

M. DEFAZIO: Okay, thank you. And that jump in '28 is more than 100 MVA. Why is that? Just because the new station is 100 MVA.

J. GILLIS: Yes. So, sorry, that's the difference between the LTR and the planning rating, so the planning rating, I believe, for the station would actually be 120 MVA.

M. DEFAZIO: Okay, thank you.

Can we go to page 21, please? So here we are talking about the Greenbank MTS. I have the exact same questions as for the Kanata. Would the answers be mostly the same? Two transformers? Underground in the station? Overhead or underground outside the station fence, et cetera?

S. HAWTHORNE: Yes, I can confirm that for Greenbank MTS it's a two-transformer station with a main tie main configuration, egress out of the station being underground to the station fence, and then generally either overhead or underground outside the station fence.

M. DEFAZIO: Okay, thank you.

And if we go down to the graph on the next page, we noted the same thing. It's more than 100 MVA, and that's due to the difference between the LTR and the planning, 100/120; would that be correct?

J. GILLIS: Yes, I believe so.

M. DEFAZIO: Thank you.

Can we go to page 29, please? So here talking about the Bronson substation, the new 13 kV substation, where you're converting the existing or what was the existing 4 kV station to 13 kV. Is the 4 kV station still in use?

J. GILLIS: Currently, yes.

M. DEFAZIO: Yesterday when -- I forget who pulled it up -- it showed the capacities of all the different planning regions, and the core 4 kV was fairly full. Do you have capacity to transfer that 4 kV off the station while you construct the 13 kV station?

J. GILLIS: Yes, the voltage conversion would be done in a phased fashion in order to make sure that we had adequate supply.

M. DEFAZIO: So when will the voltage conversion be done for the current station?

J. GILLIS: Bronson, the expected energization should be shown in the same section that we are in, and if you scroll down to the top of page 30, it's identified as energizing in 2032.

M. DEFAZIO: Thank you. I am going to re-ask that in a different way. The existing 4 kV load that's at the station now, does it need to be supplied by a different source prior to the construction of the 13 kV station? Like, do you need to demolish the 4 kV station before you build the 13? Or are you able to construct and operate them both on the same property?

S. HAWTHORNE: To construct the upgrades on Bronson DS, we will need to build the additions, net new station, in situ while the 4 kV station is in operation, and determine a cut-over plan, which will effectively move load from the 4 kV system to the 13 kV system, hence the reference to my colleague's --

M. DEFAZIO: Thank you.

S. HAWTHORNE: -- summary of a phased plan.

M. DEFAZIO: Thank you.

Again, just looking for a little additional information, the configuration of the station, dozen, dual radial, et cetera. Of the new station.

S. HAWTHORNE: The final design configuration is not yet determined for Bronson DS.

M. DEFAZIO: Okay. Do you have a transformer size or an LTR for the station?

S. HAWTHORNE: For the new station we would generally design to a top-hand rate of 100 MVA. However, I would like to note that, given the preliminary stations of Bronson, that is not yet a final decision.

M. DEFAZIO: Okay. Thank you.

Can we go to 2 Staff 90, please. So in this question, you discuss the replacement of switchgear at four stations: Rideau Heights, Parkwood Hills, Hinchey, and Russell. It seems like a very comprehensive switchgear replacement. Station transformers and switchgear tend to have similar life spans. Why is Hydro Ottawa not replacing the transformers at these four stations at the same time as the switchgear?

M. FLORES: So we assess the condition of all the assets at the station and determine the ones that will need replacement. For these specific projects only the switchgear -- or the breakers were required for replacement, not the transformers. They would still have a good condition.

M. DEFAZIO: Thank you.

Can we go to 9 SEC 87, please? And this may need to go to another panel, but I thought I'd ask in case it was you.

So I am looking at the system asset symmetrical account. Sorry, go down to page 4. And I am trying to determine what's in the system access, symmetrical versus asymmetrical account. Should I ask this of this panel, or panel 3?

L. HEUFF: Well, it would be better suited for panel 3.

M. DEFAZIO: Thank you. Could we go to exhibit 4, tab 1, section 1, please? I am at attachment A, and page 13.

So I understand this program is more of a panel 2 program, but I just want to ask a question of panel 1. In this program, we see an amount of about $1.2 million in 2026, which is the test year, and then the amount decreases over the forecast period. I was wondering if there are any other OM&A programs that this panel would be involved in that would have a similar spending pattern, where the expenses were higher in the test year and decreased throughout the forecast period?

L. HEUFF: I believe these questions would be better suited for panel 2, Ms. DeFazio.

M. DEFAZIO: Okay. I am going to ask panel 2; I am just curious of any distribution maintenance programs that may follow a similar pattern.

L. HEUFF: I am not aware of any. We would have to review them individually, for that specific anomaly.

M. DEFAZIO: Okay, thank you. And that is all my questions for today. Thank you, very much.

M. MILLAR: Thank you, Ms. DeFazio. Ms. Coban, did you have something to add?

D. COBAN: I was just wondering how we are doing, schedule wise, Mr. Millar, overall? I think we are ahead.

M. MILLAR: We are more or less on time. Yeah, we lost a little bit of time with our technical issue. I think we are more or less on schedule. So I am proposing to continue with Staff through -- we will probably be past lunch. So I am just going to propose we continue.

And I think we have Ms. Jotiban next. Are you there, Narisa?

N. JOTIBAN: Yes, I am here.

M. MILLAR: Sorry, could you say again? I lost you just for a second.

N. JOTIBAN: Yes, I am here.

M. MILLAR: Okay, perfect. I am going to hand it over to you, then.

EXAMINATION BY N. JOTIBAN

N. JOTIBAN: Thank you. Hi, everyone.

I am just going to start with response to 4-STAFF-131. So could you please pull up, in attachment A, 4-STAFF-131?

On page 1, it's titled, Ottawa provided the distribution system, time at risk and vulnerability assessment report, in a response to this question. Please scroll down to page 4. And this shows the table of contents. And scroll down. Yes. So the report has eight sections in total. Now, could you please go to page 55 of the report? And scroll down a little bit more.

I am not sure why this doesn't contain the section number, but the version that I have, it has up to section 5.5, and it is missing from 5.5.1 -- sorry. It's missing 5.5.1.2 to section 8.

So I am just wondering if you would be able to undertake to file a complete report, if there's no more information after this? It appears to be missing, if you scroll down.

L. HEUFF: Yes, we can undertake to file the full report.

N. JOTIBAN: Okay, thank you.

M. MILLAR: That's JT2.9.

UNDERTAKING JT2.9: File full distribution system, time at risk and vulnerability assessment, report

N. JOTIBAN: Will you please go to 4-STAFF-134, table 8 on page 3? If you could scroll to the last item on this table, on this page, the overall distribution?

So you previously discussed yesterday with Ms. Scott from SEC, table 8 shows program enhancement cost in 2026 under the testing inspection and maintenance OM&A program. And the program enhancement for overall distribution shows a cost increase of $1.8 million in 2026.

I am wondering if you would be able to explain if the cost increase of $1.8 million is a one-time increase? Or is this ongoing until 2030?

S. HAWTHORNE: This is ongoing until 2030, so $1.8 million per year.

N. JOTIBAN: Okay. It's the same amount every year?

S. HAWTHORNE: That's correct.

N. JOTIBAN: Okay. Thank you. My next question, I am not sure if this is for panel 1 or not, is related to the Overstory efficiency and productivity benefit calculations for the satellite imaging for vegetation management initiative.

L. HEUFF: So questions related to the specific calculation would be better suited for panel 2. However, questions related to the activities that were undertaken would be suited for this panel.

N. JOTIBAN: Okay. Yeah, I am just going to try anyway. There is also a question on reactive tree trimming costs. So could you please pull up the updated 1-SEC-27? It's the response that was filed just yesterday, page 11.

This table, it shows a description of each productivity benefits, initiative and methodology that support the calculation. So if you could please scroll down to page 12, initiative 3.2.6, the last one. Yes. And can you scroll down a little bit more, so this initiative is at the top? Okay.

So, for this initiative, in the last two sentences if you can scroll down a little bit more, please? The last two sentences under the methodology column states that:

Savings are calculated as the difference between the forest trim maintenance budget and what the budget would have been without the Overstory efficiency. Expected efficiency is 15 per cent in 2026 and 20 per cent from 2027 to 2030.

My question is could you please explain why the expected efficiency in 2026 is 15 per cent, which is 5 per cent lower than the expected efficiency of 20 per cent for the rest of the forecast period?

S. HAWTHORNE: Given the relative novel nature of the Overstory product to Hydro Ottawa, we do not expect to achieve full productivity savings until 2027, and therefore have estimated a cost savings of 15 per cent in 2026, as our learnings continue, reaching a percentage of 20 per cent in 2027, as noted.

N. JOTIBAN: So, how do you calculate the cost saving 15 percent versus 20 percent; what goes behind calculating for these numbers?

S. HAWTHORNE: The percentages are generally associated with avoided cost of reactive tree trimming, so one would take the projected reactive tree trimming costs without the implementation of overstory and generally multiply by percentages shown. For further details on those calculations, as we've noted, you can refer to panel 3, but that's the general approach. Pardon me, panel 2.

N. JOTIBAN: Okay, thank you. I have another question. Could you please pull up the updated Attachment 1, SEC-27A, please. It's 1-SEC-27A. And if you can scroll down to Row 51? So, Row 51 shows the reactive tree trimming spent under this initiative. So I used the data in this row for the forecast period 2026 to 2030 to calculate the year over year increase in the reactive tree trimming costs and noticed that the annual increase is quite lumpy. So, the year-over-year increase is 14 percent in 2027 and then it comes down to 4 percent in 2028 and 5 percent in 2029, and then it increases up to 15 percent in 2030. Could you please explain how you determined the reactive tree trimming cost and also explained the large increases in 2027 and 2030 compared to the other forecast years? So, sorry, if could just scroll to the right a little bit more so it's just missing a few more columns. So from Column H -- from column M. -- I'm sorry, column I to M. So, those are the costs and I just look at the year-over-year increase in reactive tree trimming spend. And it seems that 2027 and 2030 shows much higher increase.

L. HEUFF: We don't have the specific details on what was included in that budget readily available at this point in time. We would have to confer, likely with members of panel 2, in order to identify the specifics.

N. JOTIBAN: Okay, thank you. I will ask this question in panel 2. So moving on, could you please pull up the Excel spreadsheet for SEC-72A? Please refer to Row 14, Engineering and Design. So, this is the total cost breakdown for this program, for OM&A, and broken by different categories, inflation, shows 0.3 million, labour is 1.5 million, new IT is 0.3 million, and other is 1.6 million. And I am trying to cross reference this with the explanation in Exhibit 412. So could you please pull up Exhibit 412? Page 39. Could you please go to starting from line 17. So, there is an explanation for the cost increase of 6.3 million, and it appears that the explanation is inconsistent with the number from the response to SEC in the spreadsheet. For example, in the Excel file for 4-SEC-72 it shows the labour cost increase of 1.5 million for 2026, but in Exhibit 412, page -- this page on line 22, it shows that the compensation cost increase is 2.2 million. In the Excel file the cost increase due to inflation is 0.3 million, but Hydro Ottawa stated in this exhibit on the next page, line 5 to 6 -- could you please scroll down, please -- it shows 1.1 million cost increase instead of 0.3 million in the spreadsheet due to inflation impacts from existing programs and modernization costs. Also on the Excel file it shows 1.6 million in other category and there is no explanation in Exhibit 4. So could you please explain why the numbers do not match with the explanations?

L. HEUFF: Questions related to inflation and labour costs would be better suited for panel 2, so unfortunately we wouldn't be able to respond to that.

N. JOTIBAN: Okay. Thank you. I will ask panel 2. Could you please go to 4-STAFF-159, page 3, table A? Ms. Scott from SEC asked some questions yesterday about this table that shows forecast job titles and a number of new positions associated with each title for OM&A programs for 2024 and for the 2026 to 2030. Since the filing of the application, does Hydro Ottawa now have updated actual data for 2024 and also have specific titles and number of positions for trade under direct labour for 2024?

S. HAWTHORN: Yes, we do have that information for 2024.

N. JOTIBAN: Could you please provide updated information that also includes specific trade positions as well?

S. HAWTHORNE: Yes, we can provide actual data for 2024, direct labour inclusive of specific trade positions.

M. MILLAR: That's JT --

N. JOTIBAN: Would you be able to break it down into different type of trade position and --

S. HAWTHORNE: Yes.

N. JOTIBAN: Okay, great.

S. HAWTHORNE: Yes, the direct labour will be broken down into the different trade positions.

N. JOTIBAN: Okay.

M. MILLAR: That's JT2.10.

UNDERTAKING JT2.10: Provide actual data for 2024, direct labour inclusive of specific trade positions broken down by trade position

N. JOTIBAN: Great, thank you so much. Could you please pull up exhibit 4.11, page 10? Hydro Ottawa states that population growth and electrification are driving a significant increase in OM&A costs and affected the programs showing on this page. And, now, could you please go to 1-DRC-1, page 3? So, starting from line 7 to line 12, Hydro Ottawa stated that with an increase in electrification OM&A costs will also increase, and also stated that with increased electrification and EV penetration it will be utilizing a new CRM, or customer relationship management, which will streamline EV connection requests, automate workflows, enhance customer service, improve project intake, boost agent productivity, and track performances. These investments are designed to yield productivity and operational effectiveness gains.

I am just trying to understand, since increased electrification drives OM&A costs higher, are there any OM&A cost savings that could be realized through efficiency gains from utilizing the new CRM?

L. HEUFF: So there are two parts to the CRM platform technology. Both are discussed under Exhibit 1, tab 3, Schedule 4. Specifically, page 27 is related to the CRM platform implementation. And I will just wait for page 24 -- or 27. Apologies.

So the CRM platform implementation that is described here would be better suited for panel 2. There is also, however, elements that are referred to in the previous IR that are under Section 3.2.9, which begins on page 30, and this panel could provide some details around the efficiency savings that are expected as a result of the implementation of salesforce service for reliability of the operations, which are also under a similar platform. That would be on page 30, please. Is there one that you were specifically asking for?

N. JOTIBAN: I just read in the evidence that there is efficiency gains, but it only reflects in capital but no OM&A, and when reading the application and the response to IRR, that seems -- it sounds that the new CRM that result in increased efficiency gains might be able to result in OM&A cost savings as more electrification projects are coming on, since that's what drives OM&A costs higher.

L. HEUFF: Right. So the question's around -- that sounds like it would be the 3.2.4 CRM platform implementation that you're referring to, and those questions would be better suited for panel 2.

N. JOTIBAN: Okay, thank you. So I have no further questions for panel 1, thank you very much.

M. MILLAR: Thank you very much, Ms. Jotiban. I think we are moving now to Ms. Cheng, who is here with me in the room. If I can pass it over to you, Stephanie.

S. CHENG: Thanks, Mike.

EXAMINATION BY S. CHENG

S. CHENG: Hi, everyone. My name is Stephanie Cheng. I'm also with the OEB, and I will be asking some clarification questions regarding non-wire solutions, specifically the linkages between MyGen, EV Everywhere, ODERA, and the four proposed utility-owned BESSes, then I will hand it over to my colleague, Marley Augustine, who will continue our line of questioning regarding the non-wires customer solutions program and OM&A.

So to get started, the following clarification questions relate to MyGen, EV Everywhere, and ODERA. So as part of Hydro Ottawa's last cost-of-service element agreement under EB-2019-0261, MyGen funding of $2.2 million was approved from 2021 to 2025 under the distribution enhancements capital program within the system service investment category. Hydro Ottawa was instructed to report back on MyGen as part of its [inaudible].

In Hydro Ottawa's response to IR 1-STAFF-4 in the current application, it mentions that EV Everywhere pilot falls under MyGen, and that the ODERA project is a natural progression of EV Everywhere, aligning with the core intent of the MyGen portfolio.

Hydro Ottawa confirms that MyGen is ongoing, but is contemplating the future use of the MyGen brand.

Can you please provide a list of all pilots and/or programs that fall under the MyGen portfolio that were funded or partially funded through the MyGen budget, including linkages between these projects and/or programs?

L. HEUFF: Yes, so the listing is comprehensive as to what is on the page right now. I can confirm that the only projects that were funded under MyGen were the MyGen pilot project, where Attachment 1-STAFF-4A was also supplemented on the record for details around project closeout, the EV Everywhere pilot project, and at this point in time, although ODERA is contemplated as a natural extension of the MyGen brand, we are no longer using MyGen as the actual naming of the business unit in which we would be funding the project under.

S. CHENG: Okay. So then how does Hydro Ottawa anticipate the MyGen brand continuing 2026 onwards? For example, does it strictly encompass the ODERA project or...

L. HEUFF: The last part of your sentence was cut off.

S. CHENG: Oh, sorry. I said, for example, does it strictly encompass the ODERA project under the MyGen...

L. HEUFF: At this point in time the only project that we are contemplating that may leverage the MyGen brand is ODERA. However, the decision around how we will leverage MyGen going forward is still underway.

S. CHENG: Okay, thank you.

In Hydro Ottawa's response to 2-SEC-54, table A, it identifies the anticipated tasks and timing of the ODERA project plan, so is the approved 2.2 million budget from MyGen from Hydro Ottawa's last cost-of-service settlement agreement being used to finance the ODERA projects -- sorry, the ODERA activities listed from 2024 to 2025?

L. HEUFF: Yes, that is correct.

S. CHENG: Okay. And in general, have the goals and objectives of the MyGen brand changed since the last cost-of-service settlement agreement?

L. HEUFF: No, not at this point in time.

S. CHENG: Okay. Moving on, the MyGen Phase 2 project closeout report included as an IR attachment to 1 Staff 4A identifies key shortcomings and lessons learned. The report notes that some of MyGen's Phase 1 anticipated project outcomes did not materialize, which impacted the execution of Phase 2 proposals. Instead of scope adjustment or project pivoting, Hydro Ottawa and Enercan mutually agreed to terminate the funding agreement and reprioritize resources.

In that closeout report, Hydro Ottawa mentions that EV Everywhere is part of MyGen Phase 2, and in the current application ODERA has been described as the logical next step to EV Everywhere.

Can you please clarify if and how EV Everywhere was impacted by the shortcomings and eventual termination of MyGen Phase 2 funding agreement?

L. HEUFF: EV Everywhere was not impacted. It was the learnings from the MyGen pilot informs the next steps and the overall scope of the project of EV Everywhere. However, it was not impacted directly as a result of the project closeout.

S. CHENG: Okay. Okay. So in Hydro Ottawa's response to IR 2-STAFF-64, the ODERA project charter was provided. The project mentions -- the project charter mentions the risk management plan. Can you please specify how learnings from MyGen, which includes the EV Everywhere pilot under MyGen Phase 2, have been accounted for in the ODERA project plan to ensure success and mitigate risks?

J. GILLIS: Yes. If you take a look at response to 2 Staff 69, part E, here we have talked about how the linkages from the learnings that have been incorporated from EV Everywhere has continued to -- and support the learnings and the framing of the ODERA project.

S. CHENG: Okay, thanks.

In Hydro Ottawa's response to IR 2-STAFF-68, Hydro Ottawa mentions its contribution of approximately $900,000 in gross costs to BluWave AI's EV Everywhere pilot for their approved MyGen funding $2.2 million.

Can you please specify what Hydro Ottawa’s $900,000 contribution was used for under the distribution enhancements capital program within the system service investment category?

L. HEUFF: I don't have the specifics of what the project’s details were used for. However, generally speaking, Hydro Ottawa did fund battery energy storage systems that were installed in front of the meter and behind the meter as part of our capital funding contribution.

We also provided in-kind contributions towards Enercan -- or towards EV Everywhere, through to BluWave-ai. We would have to take a look to provide more details and specifics. However, they were generally - the contributions were to support the implementation of the deliverables and scope that are outlined within BluWave's application through the grid innovation fund project.

S. CHENG: Okay. Thank you. In exhibit 2, tab 5, schedule 4, starting on page 287, Hydro Ottawa mentions that the EV Everywhere pilot is led by BluWave. And, as part of the project, two BESSes will be installed in 2025, in response to a predicted overload scenario.

In Hydro Ottawa's response to IR 2-STAFF-68, Hydro Ottawa confirms there is no project connections between the two Everywhere BESSes and the four utility-owned BESS proposed in – BESSes proposed in this 2026 to 2030 custom IR application.

Can you please clarify which planning regions and system constraint, if any, the two EV Everywhere BESSes are addressing or intended to address?

L. HEUFF: I confirm that the two BESSes that are installed under EV Everywhere were not installed with the purpose of providing capacity mitigation in any part of Hydro Ottawa's system. They were designed to provide learnings of how we would coordinate with the IESO and how we could potentially solve overloads at a distribution transformer level.

It is a pilot project to inform the impacts to the system as well as the coordination to the IESO, but was not designed as a specific capacity mitigation like the other four BESSes that are currently contemplated in this application.

S. CHENG: Okay, thanks for the clarification.

Can you please confirm whether Hydro Ottawa owns the two BESSes associated with the EV Everywhere pilot that were to be installed within early 2025?

L. HEUFF: I can confirm Hydro Ottawa owns those two BESSes.

S. CHENG: Okay. So since it's owned by Hydro Ottawa, have you considered and assessed the viability of utility-owned BESSes from EV Everywhere to fulfill any existing e-constraints? For example, maybe the constraints that you identified in Casselman or West 28kV?

L. HEUFF: The size of the batteries that are installed under EV Everywhere are very small, and the capacity is not intended –- they are not intended for distribution capacity support. They are simply designed to show what the actual coordination would be with the IESO, as well as just to provide indicative solutioning at the distribution transformer level.

S. CHENG: Okay. Hydro Ottawa mentions linkages between ODERA to the proposed non-wires customer solutions programs in the regions of West 28kV North, otherwise known as Kanata North, as well as West 28kV, in its responses to IR 2-STAFF-69 and IR 2-SEC-54.

Please confirm if ODERA is essential to the implementation of the non-wires customer solution in Kanata North?

J. GILLIS: Yes. So the ODERA project is the foundational technology that will be used to leverage the non-wires customer solutions programming. And, without that technology, we wouldn't be able to as effectively deploy the non-wires solutions.

S. CHENG: Can you please clarify what anticipated ODERA capabilities are required to execute the non-wires customer solutions programs proposed in Kanata North?

J. GILLIS: Yes. Just let me take one second, and I am going to pull up a specific IR. Thank you. So if you take at look at the response to 2-STAFF-69, part (a), which is on page 3?

D. COBAN: Can we just have that reference again Ms. Gillis, please?

J. GILLIS: Yes, sorry. That is 2-Staff-69, part (a), subpart (ii), which starts on page 3.

D. COBAN: I am just scanning the screen, I think we might have lost – no. There you go, thank you.

J. GILLIS: Perfect, thank you, very much.

This part response here outlines the objectives of ODERA. And so if you look through the list of bullet points the first one being:

“Develop and pilot a system to predict the achievable load curtailment of customer-owned DERs, aggregated at both the transformer and feeder levels within the pilot area.”

…which aligns with the pilot areas spoken to within the contemplation of the non-wires customer solutions programs:

“Develop and pilot a system to localize distribution transformers and feeders at risk of electrical overload within the pilot area. Develop and pilot a system for the intelligent orchestration of customer-owned DERs to effectively mitigate the electrical overloads and support the driving of customer participation.”

So this is the one that outlines the objectives of ODERA.

S. CHENG: Okay, thanks. So you mentioned the importance of ODERA for the non-wires customer solutions program. Can you clarify that the non-wires customer solutions program can still be implemented, although maybe less effectively without ODERA?

J. GILLIS: Sorry, I am just going to pull up the project scope. Yeah, sorry. I was just pulling up the attachment, 2-STAFF-69(a), which is the ODERA project charter. And if you go to page 5? -- yeah, which is the beginning of section 2?

This is where it outlines the project scope. And if you just scroll down to the image. So in order for the non-wires customer solutions program to be deployed, we require the aggregator DERMS and the functional connections into the forecasting as dictated in the diagram.

S. CHENG: Okay, thank you. Given the importance of the ODERA project, in table A of Hydro Ottawa's response to IR 2-SEC-54, ODERA’s project plan indicates that the design, development and testing will take place in 2026 and 2027, with the technology being deployed between 2027 to 2028.

Can you please clarify how the timelines and interdependencies line up between ODERA and the non-wires solutions program? More specifically, when does Hydro Ottawa expect the required ODERA capabilities you mentioned here to be deployed, and does this line up with expected deployment of the non-wire customer solutions program in Kanata North in 2026?

S. CARR: Hello, Ms. Cheng. This is Shawn Carr speaking.

Just to answer your question, we are intending to deploy the non-wires customer solution program in 2026, at least most of the programs within it. And one of those programs is a residential demand response program which will rely on the ODERA project from a technology standpoint. And so, that is the main component of the non-wires customer solutions program that will be enabled by the ODERA project in 2026.

S. CHENG: Okay. Can you please confirm if the anticipated $2 million annual cost for the non-wires customer solutions program includes any ODERA-related expenses?

S. CARR: I would like to clarify that there is no ODERA-related expenses within the $2 million annual budget associated with the non-wires customer solutions program.

S. CHENG: Okay, thank you. Okay. So, in Hydro Ottawa's response to IR 2-STAFF-69, Hydro Ottawa mentions that ODERA builds upon EV Everywhere learnings, which includes support for best integration. Can you explain any inter-dependencies or linkages between ODERA and the four proposed utility-owned BESSes?

J. GILLIS: So, specifically the four utility-owned BESS that are contemplated are not within the area, the pilot area, that's being deployed for the ODERA project. However, the learnings can be applied from what we understand and unpack with respect to the deployment of the BESS that may inform some of the future programming that is contemplated.

S. CHENG: Okay. And can you please also confirm whether the $61.2 million in capital expenditures and 13.3 million in operating expenses related to the non-wires solution BESSes are inclusive of any ODERA-related expenses?

J. GILLIS: No, there is no component of the ODERA project captured within those costs.

S. CHENG: Okay, thank you. So, if the $5.1 million requested for ODERA is not funded through rates, how will that impact the implementation of the non-wires customers solutions program and/or the four utility-owned BESSes?

J. GILLIS: Sorry, just give me a moment. I know that we have answered this question within an IR, I am just looking for that. Okay. So, that can be found in the response to 2-STAFF-69, part D. And so, as stated here Hydro Ottawa is unable to speculate as to how the scope of the project would change in the absence of rate funding and we would consider those implications at the time.

S. CHENG: Okay. Can you please confirm whether Hydro Ottawa has verified that capacity added through customer owned DERs is neither available nor sufficient to address capacity constraints in West 28 KV North and West 28 KV where Hydro Ottawa has proposed a non-wires customer solutions program, as well as a 2.5 megawatt BESS respectively?

J. GILLIS: Sorry, can you please repeat the specific question?

S. CHENG: Yes. Can you please confirm if Hydro Ottawa has verified that capacity added through customer-owned DERs is not available or sufficient to address capacity constraints in West 28 KV North, or Kanata North, and West 28 KV where you guys are proposing a non-wires customer solutions program and a 2.5 megawatt BESS?

J. GILLIS: So the 2.5 megawatt BESS is actual contemplated, like you stated, in the West 28 KV system and that is for a specific need on an isolated feeder fed from the BECC with F2, and so that part of the system in the West 28 KV is not directly connected to the system in the West North 28 KV system.

S. CHENG: Okay.

J. GILLIS: So those two, I would suggest, are not related.

S. CHENG: Okay. How does Hydro Ottawa plan to balance its efforts between customer-owned versus utility-owned solutions in the future?

L. HEUFF: I would suggest that the balance will be dependant on the specific need, that's a very broad question. It would be very difficult to speculate on the specific investments that's required. However, I would state that as part of our regional planning, and as part of all of Hydro Ottawa's planning activities, we are contemplating non-wires solutions through the non-wires solutions assessment and leveraging the benefit cost analysis and we are following the non-wires solution guidelines in order to evaluate the applicability and the effectiveness of non-wires solutions, as opposed to traditional investments.

S. CHENG: Okay, thank you. In Hydro Ottawa's response to IR 2-Staff-69, Hydro Ottawa mentions that Enercan is providing $6 million for ODERA, however Enercan can terminate this funding agreement if Hydro Ottawa is not successful in securing rate funding for ODERA. Hydro Ottawa states that it does not know if the product scope will change if rate payer funding is denied. Can you please clarify whether the $6 million in Enercan funding is contingent on Hydro Ottawa receiving rate payer funding?

J. GILLIS: Yes, it is.

S. CHENG: Okay. Did Enercan provide any reasonings as to why its funding depends on Hydro Ottawa rate payer funding as well?

D. COBAN: I wonder if we are getting into a bit of a challenging area in terms of commenting on behalf of Enercan as to its rationale. I don't think we have them here in the room, and so I would be sort of cautious about us commenting on their decision-making processes. Unless there is something specific that the witness can speak to, but I just caution about that representation.

S. CHENG: Okay. That's fair, thanks. We can move on. So, the following questions are more general BESS-related questions. If we were to pull up Exhibit 2, Tab 5, Schedule 4, Hydro Ottawa is proposing four utility-owned BESSes in four different sizes and in four different NA regions. In Hydro Ottawa's response to IR 2-Staff-111 the capital cost is estimated to be proportional to the size of the BESS at approximately 2.5 million per 1 megawatt. Can you please explain what is the -- can you please let me know what is the expected useful life of a BESS? Does this useful life vary based on the size or capacity of the BESS asset?

J. GILLIS: Subject to check, we have used a 20-year typical useful life for these assets.

S. CHENG: So although they vary in sizes, you don't expect that their useful life varies between the assets?

J. GILLIS: As of right now, again subject to check, I believe we have used 20 years for all of these assets.

S. CHENG: Okay, thanks. From a technical feasibility perspective, is it possible to purchase a larger BESS than the system need, for example, purchasing a 10 megawatt BESS to address a 5 megawatt system need so that the BESS can be used to address different system constraints, perhaps in different regions?

J. GILLIS: Sorry, I would like to clarify your question. You are asking if we could leverage a single BESS to support multiple regions?

S. CHENG: No. If you are able to purchase a larger BESS than what the system actually needs?

J. GILLIS: Sorry, I am not understanding the question. Can we purchase a larger BESS than what the system requires?

S. CHENG: Yeah. So, if you were to purchase a 10 megawatt BESS, when really the system only needs 5 megawatts?

J. GILLIS: Sorry, I am I am still not clear on what the question is. If we would do that, or is there a question with respect to why we would do that?

S. CHENG: Is it technically feasible?

J. GILLIS: Is it technically feasible to connect a larger BESS than what the system requires from a capacity constraint standpoint?

S. CHENG: That is correct.

J. GILLIS: Yes, you could technically connect a larger BESS to the system to defer more of the peak.

S. CHENG: Okay. And so has Hydro Ottawa taken this into consideration in its planning?

J. GILLIS: No, right now we have specifically sized the BESS to accommodate the required needs in the system based on a capacity constraint.

S. CHENG: Okay. Has Hydro Ottawa considered or at least plan on considering the time and effort it would take to prepare and reconfigure a BESS to potentially alleviate constraints in other regions as they arise?

J. GILLIS: Sorry can you restate the question? I just missed the beginning.

S. CHENG: Sorry. Has Hydro Ottawa considered or plan on considering the time and effort it would take to prepare and reconfigure a BESS to potentially alleviate constraints in other regions as they arise?

J. GILLIS: Yes, so we would continue to evaluate the needs of the system, the use case of the BESS, and would evaluate the business case and the pros and cons of either purchasing a new BESS for the location, or if we have the ability to relocate one.

S. CHENG: Okay, thanks. So the following questions relate to the proposed 2.5 megawatt BESS for the West 28th kV [inaudible]. In Hydro Ottawa's response to IR 2-STAFF-111, Hydro Ottawa notes there is a capacity constraint with the Beck F2 feeder at Beckwith DS, as it is currently running above its planning capacity. The proposed BESS in West 28th kV would not energize until two years later in 2028, at which time the Richmond Sound MTS will also help to alleviate some load. Hydro Ottawa notes that the proposed 2.5 megawatt BESS has the possibility of extension beyond 2030.

How is Hydro Ottawa planning to manage the existing capacity constraint from 2026 to 2028 in West 28th kV, as Beckwith DS is already operating beyond its capacity?

J. GILLIS: Yes, we will be managing that time period through transfers to other adjacent stations, like we mentioned, from Janet KF4, so we do have the flexibility within those two years to continue to leverage the distribution backups.

S. CHENG: Can you please clarify the total duration Hydro Ottawa plans to deploy the 2.5 BESS after energization in 2028 in this region?

J. GILLIS: I don't believe we have set a specific time frame. We will continue to operate the BESS as we see the value.

S. CHENG: Okay.

J. GILLIS: So at this point we would consider running it for the typical useful life until there became potentially another change in the system that would require a re-evaluation.

S. CHENG: Okay. Can you please confirm whether Hydro Ottawa has considered the feasibility of any other non-wires solutions, perhaps a non-wires customer solutions program for this region? And the outcome of your analysis, if any?

J. GILLIS: Yes, so for any of the BESS that we have contemplated within the application, we have also looked into the options of customer-owned solutions. In this particular example, this is a small feeder with not that many connected customers, and what we are looking for is a reliable source and supply. And due to our inability to accurately forecast what can be dispatched from customers at this time, we decided to go with a utility-owned solution which is reliable for use in supporting our customers.

S. CHENG: Okay. Okay. So I actually have similar questions for all of the utility-owned proposed BESSes, and I am running short on time right now, so just in general, I guess, has Hydro Ottawa -- so for all of the regions you plan on deploying the BESS as stated, but you're unsure as to how long you will actually keep those in place until I guess circumstances change and whatnot; is that correct?

J. GILLIS: Essentially, based on the plans and what we know today is that we would be maintaining these in-service for their total useful life. However, we do know that there may be circumstances and needs that do develop on the grid that we will continue to monitor to ensure that these are continuing to be effective and, if not, we would evaluate a business case for their potential future deployment somewhere else or decommissioning or otherwise.

S. CHENG: Okay. So for any of the proposed BESSes, can you confirm if Hydro Ottawa has considered the feasibility -- sorry, I already asked that question, my mistake.

So for any of the proposed BESSes, if they were approved, does Hydro Ottawa still foresee requiring the traditional avoided solution that they need in the next period or within the useful life of the BESS? Because I think you guys mentioned in the application that this might avoid or defer the need, but you still expect that the capital, the traditional solution would still be required in the near future?

J. GILLIS: Sorry, I think I would like to clarify what you are asking. So right now we say that any of the proposed investments during this rate term are still required and that any of the non-wires solutions are not deferring or avoiding those. And perhaps you are talking about in the future we do see that there is the potential for these BESSes to continue to operate and potentially defer the future needs in the mid- to long-term.

S. CHENG: Okay. So then in general, what will the impact be for customers and/or the distribution system in these regions if the funding for the BESSes cannot be obtained?

J. GILLIS: I think for that specific reference you would need to look at the details for the individual reliability -- sorry, individual capacity plans that's outlined in Schedule 2-5-8, underneath Section 2 capacity upgrades. And if you go through -- I will find the specific section where we outline all of the various needs that these solutions are addressing. Let me just find that specific section.

Okay. That's starting on page 33 in Schedule 2.5.8, under the non-wires program needs, and this guess through each of the different regions in which we are proposing non-wires solutions, including the BESS, and it outlines the needs within the regions that the BESS would be supporting, and so I would suggest that it would need to look through each of those individual ones to talk about the outcomes should the BESS not be installed.

S. CHENG: Okay, thank you. That's all the questions I have.

M. MILLAR: Thank you very much, Ms. Cheng. I think we will move now to Ms. Augustine.

EXAMINATION BY M. AUGUSTINE

M. AUGUSTINE: Good morning, everyone. I am going to continue with the line of questioning for the non-wires solutions programs that have been proposed. So a lot of these questions are to clarify our understanding of the program. So moving to the core and West 13th kV region, from what we are understanding from your previous responses, the -- there is a 10 megawatt BESS that is supposed to be energized in 2030.

Are we correct in understanding that there isn't necessarily an end date for the use of the BESS in this region?

J. GILLIS: That is correct. At this time we are projecting that we would continue to use it.

M. AUGUSTINE: Okay. So for this region, Hydro Ottawa is also proposing the non-wire customer solutions program. When is the earliest that the non-wire customer solutions program would go into effect for the 13 kV sub-regions?

J. GILLIS: That timeline is not yet contemplated.

M. AUGUSTINE: Okay. And could you clarify the potential added capacity you would expect from the non-wired customer solutions program for this region?

In the application, it does say 10 to 15 megawatts, but it's not clear if it's 10 to 15 megawatts from both the 10-megawatt BESS and non-wire customer solutions, or just the non-wire customer solutions.

J. GILLIS: That would be just the non-wire customer solutions. So the 10-megawatt BESS, plus the 10 to 15, is our current projection for the non-wires customer solutions.

M. AUGUSTINE: Okay. So to summarize for this region, it's the non-wire customer solutions program will be launched, but we are not sure when. The BESS will be energized in 2030, and then the upgraded Bronson station will be coming online in 2032. Correct?

J. GILLIS: Yes. So what I would like to clarify is that as stated in other locations where we talk about the use of the BCA analysis, we have not yet conducted that within this region, and we plan to do so. And through that analysis would be our determination of the timelines for the deployment of the programming.

M. AUGUSTINE: Okay, great. Thank you. In the response to 2-STAFF-111, section (d), the proposed BESSes are referred to as the reference scenario, meaning a BCA is not required since it's the only plausible solution based on timing and magnitude of capacity requirements.

So could you clarify why, for example, the 10-megawatt BESS is the reference scenario from 2030 onwards, if the non-wire customer solution program is also proposed for this region?

J. GILLIS: So the reason is that we have looked at both of these through our assessment process from different lenses in terms of the benefits and the objectives and essentially what their use cases are.

So specifically, when we look at the BESS-use case, we are looking for reliable, dependable, dispatchable capacity, and so that is mostly the reason why we are looking at these as an alternative to the traditional wired infrastructure. And so if you do take a look at table C, which is listed in the referenced IR, 2-STAFF-111 which is on page 6?

So without going through all of the specific details in that table, we outlined why we have considered the BESS the reference scenario in terms of the costs and benefits enabled through the avoided traditional infrastructure requirements.

M. AUGUSTINE: Just to elaborate on that, we don't think that we can get the necessary added capacity through the non-wire customer solutions in this area. Is that what you are saying?

J. GILLIS: Based on our current experience and understanding and the fact that we are looking to continue to learn and grow our portfolio of the non-wires customer solutions, the timing and the magnitude of the need within the region, we didn't have the ability to rely heavily on the customer solutions programming. And that's part of the reason why we are looking to expand these and learn and grow from them as well.

So it's based on the timing and the size of the requirements and our technical abilities to use the non-wires solutions.

M. AUGUSTINE: Okay, thank you. In this same table, table C, for this region the alternative, the traditional solution would have been a new and second 13kV station alongside some transmission upgrades. So this is in addition to the upgraded Bronson station to meet incremental load by 2035. If the 10-megawatt BESS is approved, do you foresee still requiring a new 13kV station and transmission upgrades either in the next rate period or within the useful life of this 10-megawatt BESS?

J. GILLIS: So I am going to take you to schedule 258, and I will find the specific page number, where we look at the needs in the area which starts on page 44. Yeah, sorry. So can you just scroll down actually to the start of page 45, and we will look at the load forecast.

So right now, based on our forecast, you can see that the additional capacity does take us out to 2035, when you look at our planning forecast. However, with the uncertainty of the load growth with respect to what's shown in orange in the IRP forecast, which is based on the reference scenario of the decarbonization forecast, we will have to continue to monitor to determine whether or not a second station will still be required based on the output of both the non-wires customer solutions programs as well as the BESS that we intend to install.

M. AUGUSTINE: Okay, thank you.

Moving on to the non-wire customer solution program in Kanata North, in response to a previous question, it was stated that the non-wire customer solutions program for this region may -- could be implemented as early as 2026. Correct?

S. CARR: Good morning, this is Shawn Carr speaking. Yes, that's correct. The timing for the deployment for the non-wires customer solutions program is in 2026, in Kanata North.

M. AUGUSTINE: Yes. And then in Kanata North, there is a new Kanata North station that is expected to be energized in 2028. Would the non-wire customer solutions program continue past the point at which this station is energized?

S. CARR: So the non-wires customer solutions program is intended to bridge the gap between now and when the new station comes online. However, the non-wires customer solutions program, the analysis that was done by the BCA, you will see looks at the 2026 to 2030 period, with the majority of those programs running between 2026 and 2028.

M. AUGUSTINE: Okay. So for after 2028, it is continuing, but to a lesser extent?

S. CARR: There is actually only one program within the proposed six that is running, being proposed to run beyond 2028. The other five are being proposed to run from 2026 to 2028. That's the timelines that were assumed in the BCA analysis that was completed.

M. AUGUSTINE: Okay, thank you. And then for the 2026 to 2028 period, were there any other alternative solutions that were considered to meet this capacity constraint?

J. GILLIS: Within this area, we have considered the non-wires customer solutions the only viable option given the short timeline that we have to bridge the gap in the area and the amount of time that it would take to plan and construct any other wired alternatives. And so this becomes the reference scenario, because there were no other opportunities in this area.

M. AUGUSTINE: Okay, great. Thank you, that's clear. For the last set of questions, we wanted to ask some clarification questions around the non-wires OM&A spending. I think as a -- it would be useful to draw up exhibit 2, tab 5, schedule 8, page 49. There is a table 2? Yes.

So the first thing refers to Hydro Ottawa's response to 2-SEC-53. It mentions that there is a $10 million funding request for customer incentives for the non-wire customer solutions program. So could you confirm that that $10 million specifically refers to the line that's written:

“Other revenue expense, non-wire solutions”?

J. GILLIS: Yes, that is correct.

M. AUGUSTINE: Okay. And then in the same response for 2-SEC-53, it mentions customer incentives, and then also incentives for third parties and incentive payments in reference to this $10 million budget.

Could you confirm whether the $10 million or the $2 million annual is inclusive of any incentive payments to Hydro Ottawa, such as a margin-on-payments incentive for the use of third-party DERs or non-wire solutions?

D. COBAN: I think that question might be better directed towards panel 3, which is dealing with regulatory matters related to this proposal.

M. AUGUSTINE: Okay. That s fine.

For the next piece, there is an annual $2.8 million budget mentioned for non-wire solutions OM&A in different parts of the application, and in Hydro Ottawa's responses to the interrogatories. So I just wanted to confirm that there is -- they are mentioned under different names, that there is only one 2.8 -- $2.6 to $2.8 million budget under for non-wired solutions OM&A. So in this table it would be the non-wire maintenance account, the line, and for in Schedule 4, Tab 1, Schedule 2, that it's referred to non-wires programming and system integration, and in the IR 4-STAFF-134 it's referred to as third party non-wire alternative; that all three of these are the same, $2.8 million?

L. HEUFF: I am just confirming all three are the same.

M. AUGUSTINE: Okay, great. Thank you. Could you clarify whether the $2.8 million only relates to expenses related to the non-wire customer solutions program, including staffing?

L. HEUFF: No, it does not. It also includes others, it is also contemplating other expenditures related to management of non-wires solutions such as battery energy storage systems.

M. AUGUSTINE: Okay, great. So, for example, this budget would include -- so $20,000 is mentioned for maintenance in response to 2-STAFF-111 for each of the battery units, so this, this line would be included in the 2.8 million, staffing, management, maintenance?

L. HEUFF: Can you repeat the reference, please?

M. AUGUSTINE: Sorry. There is a budget, there is a budget table, if you go further up here that mentions things like $20,000 for each year for the BESS units. So this would be included under the non-wire solutions OM&A budget line, correct; out of this 2.8 million?

J. GILLIS: Subject to check, I don't believe it is. I believe that that's captured under the battery energy storage system line item that's contemplated under our operating and maintenance program for the testing, inspection and maintenance programs, which you can find in Schedule 412.

M. AUGUSTINE: Okay. Okay, then moving on. In response to 2-STAFF-70, Part A, Hydro Ottawa mentions investigating opportunities to develop shared capabilities and tools to administer a local flexibility market for non-wires solutions programs which would be funded through the non-wires programming and system integration OM&A budget. So, could you confirm whether the 2.8 million already includes some amount for this potential local flexibility market initiative?

L. HEUFF: At this point in time there is no funding associated or any request associated with local flexible markets.

M. AUGUSTINE: Okay. And then could you confirm whether Hydro Ottawa plans to come forward within this rate term with a separate and comprehensive application for the local flexibility market initiative if it materializes?

L. HEUFF: If it materializes, it would depend on how the actual funding would be applied. Activities associated with the local flexibility market could be capital or operating in nature. Hydro Ottawa would review the program and the available funds, or the available dollars, to support such an initiative. Should there be operating and maintenance funding that is required in order to support it, you would be correct in assuming that it would come out of the $2.8 million that is under the third party costs and the non-wires solutions that are indicated in there, and Hydro Ottawa would be obligated to ensure that it is able to manage within that amount of funding. Should it be required for capital investment, it would come from within our grid modernization portfolio of dollars and we would be, again, responsible for ensuring that we are able to, effectively manage our budgets.

M. AUGUSTINE: Okay, great. Thank you. We don't have any more questions for the non-wires piece.

M. MILLAR: Thank you very much, Ms. Augustine. Panel 1, your labours are almost finished, but we actually have a couple -- I've got a notification we've got a couple short follow-ups on a couple of matters. So, Ms. Coban, if we could do that, I think we can still wrap up by 1:00. Subject, of course, to any -- actually I forget, do we -- no, sorry. This is not cross-examination, so there is no re-exam. I forgot I am not a commissioner.

D. COBAN: I think it would be good to wrap up before the lunch break. That will give us a chance to get the panels switched over and the technology all set up.

M. MILLAR: Okay, great. I still think we will be done by around 1:00. Mr. Rubenstein, I know you had something but Ms. DeFazio had a quick follow-up on something.

M. DEFAZIO: Hi. I would just like to follow-up on a question I had about Hydro Ottawa's maintenance of assets past typical useful life. Could we please go to Exhibit 4, Tab 1, Section 2? Down to page 10. Thank you. So, here on line 6 it explains that maintenance includes insulator washing to prevent contamination-related failures, thermographic scanning for early detection of equipment issues, and switch maintenance to ensure functionality of critical overhead and underground distribution switch gear. That's an example of some maintenance work done on distribution equipment. If we could also go down to page 28? Okay. So, here under Station Switch Gear it, the table, includes information on the type of maintenance that is done, functional testing, contact resistance testing. So these two items are just examples of maintenance that's done by Hydro Ottawa on some of its distribution equipment. There's others in the exhibit of course. If we could go back to 2-STAFF-43, please? And down to the answer for part C. So, this is where it says, or Hydro Ottawa states:

“It has concluded that more frequent inspections are a better investment than immediate rehabilitation or maintenance of assets that are at or beyond their typical useful life but in adequate condition." [As read.]

What I would like to clarify is: Does this mean that the examples of maintenance we just reviewed, would not happen on equipment that is at or past its typical useful life, or would that equipment also receive the same type of maintenance activities?

M. FLORES: It will receive the same maintenance activities.

M. DEFAZIO: Thank you very much. That is all I have.

M. MILLAR: Thank you, Ms. DeFazio. Mr. Rubenstein, are you there?

M. RUBENSTEIN: Yes, thank you very much. Panel, if you recall yesterday during my questioning we had a question relating to the IRRP forecast that Hydro Ottawa provided to the IESO as part of the process. And we had asked for the load forecasts that you had provided the IESO and you directed me to look at the appendices of the Ottawa subregion report; do you recall that, Ms. Flores?

M. FLORES: Yes, I do.

M. RUBENSTEIN: So I went and looked at that, so thank you very much. I think it's not actually contained in the appendices for report, but there's some data tables that were provided during the webinar which provided the consultation. And I've reviewed that document and one of the things which causes confusion to me is that that document obviously includes, not just Hydro Ottawa's stations, but also the Hydro One stations that serve, I guess, the Ottawa subregion. And even when I try to pull those out, or at least the ones I think are because I know some of the stations have joint ownership, I get different numbers than the aggregate numbers that you provided in the context of 3-CCC-34, where you provide the 2025 and 2030. So I am going to actually ask what I had asked originally: If you can provide the information that Hydro Ottawa provided to the IESO and, if there is any differences between that information and the forecast load that you're including in 3 CCC 34, if there are any adjustments or anything, you could explain that?

M. FLORES: Yes, I can provide the attachment only with Hydro Ottawa stations load.

M. RUBENSTEIN: Yes, and if there is any differences from the information that you're showing or -- or you can draw that parallel where those numbers come from.

M. FLORES: Yes.

M. RUBENSTEIN: That would be helpful, thank you very much.

M. MILLAR: Okay. That's JT2.11.

UNDERTAKING JT2.11: Provide the information that Hydro Ottawa provided to the IESO and, if there is any differences between that information and the forecast load included in 3-CCC-34, any adjustments or anything, explain such

M. MILLAR: Is that all, Mr. Rubenstein?

M. RUBENSTEIN: Yes, it is. Thank you very much.

M. MILLAR: Okay. Great. I think that concludes panel 1, so thank you very much for one and a half, what were long days for you, I am certain, but thank you for taking the time to answer our questions.

Just one quick administrative note. My co-counsel Ms. Nowicki will be taking my place this afternoon, so you will be under her care. Ms. Coban, anything more before we break?

D. COBAN: No, I think we are good, thank you.

M. MILLAR: Okay. I'll see everybody at -- or Ms. Nowicki will see you all at 2:00.

--- Upon luncheon recess at 1:01 p.m.

--- Upon resuming at 2:03 p.m.

J. NOWICKI: Good afternoon, and welcome back to Day 2 of the technical conference. As I mentioned before we got started, my name is Julia Nowicki. I am OEB counsel and I will be taking over hosting for the remainder of this afternoon.

We will be continuing this afternoon with panel 2, so I will pass it on to Ms. Coban to introduce our panelists.

HYDRO OTTAWA LIMITED – PANEL 2, GENERAL PLANT DISTRIBUTION SYSTEM AND PLAN INVESTMENTS AND RELATED OM&A AND STAFFING WORKFORCE, CUSTOMER ENGAGEMENT, BUSINESS PLANNING, CORPORTAE GOVERNANCE AND OTHER REVENUE

ANGELA Collier

ANDREW WILLIS

JOSEE LAROCQUE

TREVOR FREEMAN

DONNA BURNETT VACHON

LOUISA YEUNG

D. COBAN: Good afternoon. Panel 2 is here to speak to general plant distribution system and plan investments and related OM&A and staffing workforce, customer engagement, business planning, corporate governance and other revenue, as noted in the letter that Hydro Ottawa filed on September 8.

And I would now like to just turn it over to the panel members to introduce themselves, starting with Ms. Collier, please.

A. COLLIER: Good afternoon, panel. Good afternoon, it's Angela Collier, vice president of finance. I will pass it over to Andrew.

A. WILLIS: Good afternoon, everyone. My name is Andrew Willis, and I am representing IT. I will pass it over.

J. LAROCQUE: Hello, everyone. My name is Josee Larocque. I am the director of communications. And I will pass it on to my co-worker, Mr. Freeman.

T. FREEMAN: Good afternoon, everybody. My name is Trevor Freeman. I am the manager of commercial accounts and program delivery. And I will pass it to my colleague, Ms. Burnett Vachon.

D. BURNETT VACHON: Good afternoon. My name is Donna Burnett Vachon. And I am the director of change and organization development.

L. YEUNG: Good afternoon. This is Louisa Yeung, director of finance.

D. COBAN: Those are all the panelists on panel 2. So we can get started.

J. NOWICKI: Thank you. First up on our schedule, we have VECC. So Mr. Garner, please proceed.

EXAMINATION BY M. GARNER

M. GARNER: Good afternoon, panel. My name is Mark Garner. I represent the Vulnerable Energy Consumers Coalition, or VECC. I am joined this afternoon by my partner, Bill Harper, who may have some questions. But I will start it off. I believe I am allotted an hour; I am hoping that it will be less than an hour if we are all very efficient, although there is no prize for being the first panel member to answer a question.

I am going to start with VECC 35. But instead of bringing up VECC 35, I think the place to bring up would be the Excel spreadsheet that was referenced and attached to that interrogatory. So it's called VECC 35A, USofA accounts. And I just wanted to go through that document.

And this may be a little bit difficult for our very able help today, but I am also going to reference a couple of interrogatories by the Consumers Council of Canada, and those are 45 and 46, as we just go through this exercise I just want to do.

So panel, what I am doing is I am just trying to understand a few life anomalies or difficulties between - the different ways the evidence is being presented. And I suspect it's just a presentation; there are some presentation issues.

But one that I wanted to go through first is with respect to just generally the numbers that you see here in table 2-JC, by these categories here. If you will notice on the very left, you have the program’s name. So you have collections, and collections are 5320, right through to basically 5335 accounts.

And what I just wanted to make sure, I have done the math myself for one year, but just to confirm with someone on the panel: If you look at CCC-45 or CCC-46, you will see tables that also deal with collections, or one deals with another category, I think customer and consumer relations. And I believe these are just different representations of the same amounts because when I add them up, they seem to be exactly the same.

So as an example, if I take customer billing and I take the three accounts, 5320, 5333, 5335, I am getting the same total as I get in table A of 4-CCC-45. Now I know those are two documents you have to put side by side, but I wonder if you can just confirm that that is correct, I am doing - the math is correct that way.

L. YEUNG: Hi. This is Louisa Yeung, director of finance. So the two files that they reconcile each other, the Excel file to show that appendix 2-JC are all the names, broken down by the USofA. And that is based on the OEB accounting handbook, versus that those costs breakdown provided through the CCC IRs, that we use our internal business unit and object accounts to provide a better understanding of what they are representing.

M. GARNER: Right. But ultimately what I am driving at Ms. Yeung is the way I saw it is they ultimately reconcile in total. So the total of customer billing of table A is really the total of customer billing of all the accounts in the USofA. They are different snapshots, different visions of them. But their totals are the same. So I added up all the customer billing or collections line that, you know, let's take customer building; that's in table A of CCC-45.

I take all the customer billings in the USofA, I add them up. And for 2026, I got the exact rounded, you know, with rounding error -- the same total as I get for 2026 in table A of the CCC.

So they reconcile in the totals, don't they?

L. YEUNG: Correct, yeah.

M. GARNER: All right, thank you. I just wanted to make sure, because there are a few tables they have used, and that's the way I saw it.

Now, in the USofA account version of customer billing, if you look at line 9 - and in this version, you don't see this meter-reading expense line per se in the table A of CCC’s 45. So it's within there; it must be within the table because we just established the totals add up. But it's a separate snapshot of this.

And what I was curious about is why is the meter-reading column, which is account 5310, why is that almost tripling in the years between 2025 and 2026, from 350 to 952? You can't see it in the table, because it's not really separated out in the table like that.

So can you help me with why that number goes up, not threefold, but close to threefold?

L. YEUNG: Subject to check, I believe that increase is to deal with the AMI metering renewal.

M. GARNER: Okay. And I take that, subject to check, and if there needs to be a revision. Thank you, that would help, that helps.

Now here is another number, and let's go back to Appendix 2-JC, USofA. If you go back to line 20 on property insurance, there seems to be an anomaly with the 2021 actual, or at least it just seems odd. There is a $2 million number there, whereas the following numbers of actuals are in the under $200,000 kind of range. So it just struck me as what's going on with property insurance? Under the board s actual, there is something, in 2021, that's so different from every other year after it.

Can you help me with that?

L. YEUNG: Right. The insurance premiums that were allocated between three different JC classes, included corporate calls, facility and distribution operations, and also there are a total of five different USofA that represent a total of insurance.

Now what you are seeing the spike in 2021 is just because of that, we were trying to reallocate them to the proper USofA in the following year.

M. GARNER: Okay. So that number just is allocated differently, subsequent. So it's 140, but if I go in other accounts I would see somewhere near the $2 million range again, but just added up in those other accounts. That's what you are saying to me?

L. YEUNG: Yeah. So that's why we are providing the other CCC IRs that, in that view. So that we will have a constant view of what the property insurance represents, instead of here that, you know, sometimes that we are trying to reclass of USoA, in between.

M. GARNER: Okay, thank you. I am not sure you need bring it because, Ms. Yeung, you are helping me through, I understand, sort of accounting issues and this is one I saw in a couple of places but we will use this one as an example. If you go to, in facilities, if you go to line 50 you will see an administrative transfer credit which, as you say, when I go to the CCC IRs and ask, let's say, about facilities I don't see a transfer credit in that table. Again, the totals all add up, it seems to me anyways, and I think you have confirmed that, but this snapshot in the USoA account is showing me this transfer credit. Can you help me with what is that transfer credit line that exists here, and it does exist in a few other places I think; what is that? What is that and how does it relate to, let's say, taking table A at CCC-48, you know like, how does the transfer credit translate to that table?

L. YEUNG: So this line represent the facility service provided to other affiliate companies and also related to other cost allocation, so that's how facilities get a credit for this line. And in CCC-48 that would be embedded into one of the line items in there.

M. GARNER: It would just be offset to one of the lines that we are looking at in that table; is that what you're saying?

L. YEUNG: Correct.

M. GARNER: Okay, thank you. Now, can you help me with, and maybe there is an answer, I didn't find a table, another table that was as you have done with the other ones, broken down, so I could compare that table to the US of A. But maybe you can just help me generally. If you look at line 61, Human Resources, in this one and you go to office supply and expenses, there is I call it an anomalous increase, it is sort of running into the 400 less than 500,000 and then beginning in '24 it jumps quite a lot into the million -- close to the million dollar range. There seems to be something -- I am not sure if that's actually a cost increase, again, or if that's showing me a snapshot of something that's changing in how one's presenting the information; do you know what I mean?

L. YEUNG: Yeah, I cannot speak to that details.

M. GARNER: Maybe you could undertake to do this, the simple question would be is: Is account 5620, office supplies and expenses, is that a true increase each year or is that also a change in allocations between accounts for any of those sums? So I am just trying to understand, is it clearly an increase each year or is there any allocation changes that are being made; can you undertake to clarify that?

L. YEUNG: Yes, I can. So, this undertaking -- sorry, this undertaking is to clarify that the US of A 56 -- sorry, 5620 --

M. GARNER: Right.

L. YEUNG: -- whether that increase is an increase actual increase or US of A reclass? So that is the undertaking?

M. GARNER: Right. And I would like to add to that, though, is: If it is an actual increase, that there be an explanation in the change I am really looking for is between the $398,000 moving up to basically $1,000,047. That seems to be quite a big leap, so I am assuming there is a singular explanation for that leap and maybe somebody could provide, along with that clarification you are making, if it is, in fact, an increase what it relates to?

L. YEUNG: May I take you to Schedule -- Exhibit 4-1-2, so it is Exhibit 4, Tab 1, Schedule 2. There was a Table 23.

M. GARNER: And does that have it?

L. YEUNG: I just wanted to point out that the total program cost increase is increased by $334,000 in 2026 compared to 2025. So the total is $300,000 increase.

M. GARNER: Well, that's kind of why I was going there. And if you notice, again, there is in this one, Ms. Yeung, there is one of these transfer credits that are happening in this account, you can see it just below it, right? Which is doing some offsetting of that increase. Now, leaving that aside, that is what I am trying to understand is: Is that, what I'd call office supplies, are office supplies actually going up from 400,000 to a million dollars, or is somehow something getting mixed up with these transfer credits and things? Because, as you say, when you total everything it comes out to a different number. And it's much like why I brought you to the metering, the customer billing thing, is when you total that number it's quite different than taking one line, which is like on meter-reading expense and that one goes up quite a lot. So, again, I am trying to understand in a similar fashion for this one, is that a real increase and if it is a real increase what's it relate to?

L. YEUNG: So I can take this undertaking.

J. NOWICKI: So that will be JT2.12.

UNDERTAKING JT2.12: Provide a greater explanation

M. GARNER: Thank you. Thank you for that. I think I want to move on to another area. And it is to do with -- I want to make sure I have the right interrogatory. I believe it's 2-VECC-12 and it's about the number of vehicles. And in the response just before this on the second page, it's just before Table A, this is Table A in there, right there. Just above that, in the paragraph where the answer is, above that table. It says, basically, as such Ottawa -- you can't see it, you have to scroll downward I guess, it's -- no, the other way, sorry. Upwards, I guess. There, that paragraph. You will see it says:

“As such, Ottawa will purchase 21 fewer vehicles reducing the needed for additional head count from 55 34.” [As read.]

Sorry, I am a little confused here. Are you making a change to the application? Did you have in the application 55 and then in responding to this interrogatory you have said we are changing it to 34; can you clarify?

A. COLLIER: Certainly. It's Angela Collier. No, in the application we have only put in the budget for 34, we just wanted to show that the original request was 55 vehicles, but through our pooling initiative that's described in Schedule 134 we are reducing the ask by 21. But our application only has costs for 34.

M. GARNER: Thank you, Ms. Collier. Okay. My next place -- okay, I'm sorry. Okay, my next place is -- oh, the next one is VECC -- 4-VECC-39. Excuse me. And we asked you for some membership fees here. And we asked you for the premiums you paid to MEARIE and you've redacted it and I am not debating the redaction, I understand why. But we, we -- I don't look at redacted work, I take some umbrage to it. But, nonetheless, what I wonder if you could help me with instead, because this is redacted. Is it possible, without any issues happening, instead of giving me the actual premiums you could give me, for this table, using 2021 as your starting point the percentage increase or decrease in premiums over the years? Again, what I am testing here is because they are a related company I want to have some comfort, I'm looking for some comfort, that the transactions seem reasonable. And it seems to be one way to do that would be to look at the percentage increases over the years from '21 -- using '21 as your base and then so '22 you would say it's a 5 percent increase or whatever, '23, you know, et cetera, et cetera, et cetera; could you do that without violating any of the principles that you had for redacting this?

D. COBAN: Mr. Garner, this question is for panel 3, they are equipped to deal with insurance premiums. But --

M. GARNER: Oh, okay.

D. COBAN: -- just looking at it on its face your request, I think, we would still want to look into whether that raises any issues of confidentiality, since we would be sort of disclosing price escalations that have been agreed to under this contract with MEARIE.

M. GARNER: Maybe it would or maybe it wouldn't. And, yeah, you are right. It says panel 2 or 3. Maybe I could leave it like this, Ms. Coban, I won't raise it again, you have heard my request and you can take it back with you, and maybe tomorrow once they have listened to this you could respond to whether that's a possibility to do; would that be okay with you?

D. COBAN: How about we just give it an undertaking and set out in writing. If we can give you something we understand what you are looking for, we will; if not, we will just note that providing that information you requested would result in confidentiality concerns.

M. GARNER: That sounds good then. There is a pin in it. At least we know where it is going or not.

J. NOWICKI: That will be JT2.13.

UNDERTAKING JT2.13: Provide the percentage increase or decrease in premiums over the years starting 2021

M. GARNER: Thank you. The next place I wanted to go is -- sorry, I am just looking at -- I'm sorry, just looking at my sheets here next to this thing where I have lost where I was. And if I go to 2-VECC-42, I believe is the one I am looking at. If you -- in 2 VECC -- sorry, 4-VECC-42, pardon me, 4-VECC-42. That doesn't look like my 4-VECC-42. Why does mine look different than yours? No. Mine has a number of full-time positions. Is there more than one -- page 2 of 3, sorry, pardon me, I didn't realize -- I only have page 2 of 3 up. Yes, this one. It's the -- the number for 2024 of the FTEs hired in this table confused me, I believe, because when I went to -- when I go to Appendix 2K and I look at the difference between '23 and '24 in FTEs, I thought I got a number of either 134 or 132, I think, depending on one of the updates, and not 101.

And so this number is smaller than the number that seems to come out of Appendix 2K. Am I just doing my math wrong, or is there something different about this than what's in Appendix 2K?

D. BURNETT VACHON: Can I just ask you to repeat your question? We are comparing --

M. GARNER: So what you are comparing is -- sorry, I will let you finish.

D. BURNETT VACHON: No, go ahead.

M. GARNER: Yeah, Ms. Vachon, what I am comparing is, I went to Appendix 2K and I looked at the difference between 2023 actual FTEs and 2024, and that's 495 versus 624 in actuals. It was 628, and in actuals it came in at 624. That difference is not the difference -- I am trying to figure out -- that doesn't seem a difference of 101 people, that seems to be a difference of 130 people. And so it looked to me like you hired more than that, or maybe I am supposed to add up both years. It's 137, and I am adding up 2023 and 2024 to get that difference?

D. BURNETT VACHON: No, I think the difference is because you're looking at FTEs --

M. GARNER: Right.

D. BURNETT VACHON: -- 2023 is lower based on our 84-day strike, so the hours for our unionized employees would have been pulled out of that number, so it reduces the 2023 number.

M. GARNER: Oh, okay, okay, thank you.

D. COBAN: Mr. Garner, I am sorry to interrupt. I have just been advised that Ms. Yeung is having some technical issues. She has actually lost the connection through her laptop. So I think maybe we can ask to give her a moment to reset, just to make sure that the panel is all available to answer your questions.

M. GARNER: I am in your hands if that is how you would like to proceed. You know best. Maybe I can...

D. COBAN: Ms. Nowicki, is that okay? I think we are just looking to reboot, and she will be back online. I apologize for the difficulties.

J. NOWICKI: Yes, that's okay. We can take a few minutes --

D. COBAN: Thank you.

J. NOWICKI: -- wait for her to return.

M. GARNER: I will try and use my time constructively to eliminate some things here.

D. COBAN: Okay. It looks like she is back online.

J. NOWICKI: Okay. Great. Thank you.

D. COBAN: Thank you.

M. GARNER: The next place I would like to go is to 4-VECC-40, and this was a question about shared services with the affiliates of Hydro Ottawa. And what I wanted to ask you was, in this -- for this, again, I was looking at two pieces of this evidence or answers to interrogatories just to kind of make sure I am understanding how they match. If you go to CCC 57, they asked for a percentage of corporate costs allocated between HOHI and HOL, and you have given them that table. It's called Table A. And what I am trying to understand is, I asked -- we asked kind of a similar type of question, and if you look at that question, that's at page 3 of 3 of 4-VECC-40, and what I am trying to understand is, the percentages allocated, I think even in the response to the CCC one, it references 4-VECC-40, and it says for an overall percentage of the FTEs allocated.

So I just want to make sure that what I am looking at when I look at Table A -- I believe it would be Table A -- in 4-VECC-40, is a, I guess I would call it a weighted percentage of what I am seeing when I look at Table A of CCC 57. So the way maybe to make it a little less unclear is, if I took 2021 in CCC 57, it's full of different percentages for the different units, 50 per cent, 75, 80, 46, 38, 53, and 0. What I think I am looking at for 2021 for the same year when I go to VECC 40, which is a number of, I think 54 percent, is what I call a weighted average of those same numbers, and that gives me 54 per cent? Is that -- am I correctly interpreting that?

A. COLLIER: Let me just confer with the panel for a second.

M. GARNER: And I am sorry, I know you are conferring, but I think it might be Table B, 81 percent that is the table that is the -- in VECC, that's the one that is equating.

A. COLLIER: Sorry, Mr. Garner, could you just repeat your question just to make sure I have understood it well?

M. GARNER: Yeah. I am not sure I understand it well, so I will repeat it and see if I can understand it.

A. COLLIER: Okay.

M. GARNER: So what I was trying to understand is, again, you do reference the two IRs to each other in a way, and so it makes sense to me, but I just wasn't quite sure I would have this right. So you -- I think it's Table B, and Table B, I have got the labour costs allocated between the two affiliates, Ottawa Hydro and the holding company, and in 2021 you have got a number of 81 per cent there; right? If you are looking at that table.

Now, if I go to 2021 and the table at CCC 57, I don't get a single number of allocations, I get -- I get columns of allocations, right, of different allocations. But somehow what I thought I was reading was, if you weighted these somehow you would get to 81? Again, that doesn't make sense to me, because none of the numbers there are as high as 181, but --

A. COLLIER: So, no --

M. GARNER: That is why I say, you explain to me how the Tables A and 57 and the tables you gave me, the two tables in 40, how they relate to each other.

A. COLLIER: Sure. So if we start with VECC 40.

Table B, first of all, doesn't really relate to the percentages at all in CCC-57, as you have referenced. This is what proportion of labour costs is allocated versus other costs that are part of the corporate allocation, like IT costs or facility costs or IT. So that's just the proportion of labour.

M. GARNER: Right, right.

A. COLLIER: And it is mostly people, so it is a higher proportion. Table A, if we understood your question correctly, we were trying to calculate how many - if we take those allocations on CCC-57 in each of those areas, how many employees are part of the corporate allocation from the holding company to HOL. So basically it is saying the holding company has 38 employees in total, if we look at the test year of 2026, and 23 of those employees end up being allocated to HOL using that percentage in the other IR in CCC-57.

M. GARNER: I see.

A. COLLIER: But it's trying to approximate how many employees in total.

M. GARNER: Okay, I think I see. So in table A of VECC 40, what you are saying or demonstrating is that if you are looking at an FTE allocation of labour, that has increased from 17 to 23, just on the way that labour is being allocated. And that's what that is showing, from 54 to 61. Right?

A. COLLIER: Yes. The corporate allocation from the holding company from 2021 to 2026 changed from an approximation of 17 people to 23.

M. GARNER: Now just to be clear, Ms. Collier, that number, that increase, that never shows up like in appendix 2K as an FTE number, right? That just shows up as a costing number in something; there's no FTE. This is a notional thing in the sense of FTEs, because it doesn't show up in your appendix 2K, does it?

A. COLLIER: That's correct. It does not show up in appendix 2K. It is part of the OM&A costs under corporate costs.

M. GARNER: Right. Now one of the things that - well, I guess my question is this: Can the reverse be done? So if you looked at the originals of the shared services with, now Hydro Ottawa, with the holding company, the capital core, energy services, and maybe I guess the conservation and framework, although it seems negligible, could you do a table A in the reverse of that that would actually show the other way around, how many FTEs Hydro Ottawa has in a sense allocated over those same years to those three or four different affiliates?

A. COLLIER: It would be much more difficult to do this in the reverse, mainly because when we are allocating in table A, when we are allocating from the holding company to Hydro Ottawa through the corporate allocation, it is primarily people cost that we are allocating.

However, when we are doing it in the reverse and HOL is allocating to the affiliates, there are many, many costs, right? There are system costs, there are space costs, there is people cost. And each business unit, you know, has kind of its own mix.

So it would be, you know, quite an undertaking to unravel all that and calculate it on a per FTE basis.

M. GARNER: Would that be the same as - would you have the same problem doing it, like in table B, the labour-related costs? Just saying is what all the labour costs that Hydro Ottawa has provided, percentage wise, to each one of the individual affiliates?

A. COLLIER: I think the same amount of work would be the same.

M. GARNER: It would be the same.

A. COLLIER: Because it would be going, like BU by BU – like, I try, just think about my own finance team. You know, the A/P team has different costs allocated to it than the billing team and whatnot. So we would have to go through every BU to do either table A or B.

M. GARNER: Yeah, fair enough. I don't think I need to torture you that badly --

A. COLLIER: Thank you, I appreciate that.

M. GARNER: I am just trying to understand that, okay, thank you.

Let's see, the next section. This is 1-VECC-6. And again, it's relating another piece of information again from CCC. And I just want to be clear as to what I am looking at. So we asked you about third-party engagement costs.

In CCC-9, 1-CCC-9, they asked you about engagement activities per se, like holus bolus, I suppose. I just want to be clear that when I look at the table we asked for, table A - and I will just take 2024. The engagement costs, third party, were $302,300. When I look at CCC 9’s table A, at 2024, I see various different amounts in there.

That $302,300, that will be embedded somewhere in 2024 as one of those, in that column somewhere? Is that correct?

T. FREEMAN: Hi, Mr. Garner, it's Trevor Freeman. So the question that you asked in VECC-6 was specific about our customer engagement survey costs, I believe.

M. GARNER: Right.

T. FREEMAN: So the $302,000 also includes our rate application survey engagement that we did in 2024.

M. GARNER: Right. And that, though, what I am trying to get at, that $302,000 shows up, although it's not showing up specifically, it shows up in the 2024 column of table A in CCC-9, does it not? Just I don't see it, but it's embedded in one of the descriptors in there? Or is it not?

It is a separate cost, or is it somehow part of the cost that you see here, in that team?

T. FREEMAN: I am just going to confer with my colleagues for one moment. I am just going to pass you to my colleague, Ms. Yeung.

L. YEUNG: So, in VECC-6, the rate application customer engagement survey calls, that is actually deferred to the next five year, 2026 to 2030, as part of the rate-up calls included in appendix 2N. So that is why it is not in the other IR, CCC-9.

M. GARNER: It is not in that table, then, you are saying?

L. YEUNG: It is not.

M. GARNER: Okay, thank you, and I will thank you for that clarification.

And I think my final question - Mr. Harper may have a question or two - my final question relates to CCC-35. This is about labour costs for contracted labour. And, you know, each one of the areas has an internal and a contracted labour amount; it's table A on page 2 of 4-CCC-35. And, again, I have a feeling I know what the answer of this is but I will ask it anyways.

If I was trying to - when you put down the contracted labour costs here, summary of labour costs by JC, are you able to, because you are able to say these are the labour costs, are you able to ascertain the FTE and/or employee number that goes along with that cost? Do you know what I mean?

L. YEUNG: I believe the internal FTE has already been included in one of the IRs. Let me just pull this up.

M. GARNER: Oh, okay, I didn't see that. That would be helpful.

So you are saying that somewhere there is a schedule that matches those numbers to FTE numbers, those dollar numbers to FTE?

L. YEUNG: So that should be in CCC-50.

M. GARNER: Okay. If I may, maybe we can just bring it up?

L. YEUNG: In table C.

M. GARNER: Now these are third-party consultants? These are third party; these are internal, aren't they.

L. YEUNG: This is our internal, this is our internal.

M. GARNER: Yeah. No, what I was trying to do was I was trying to attach a number to the contracted version. Because I was thinking this to myself, I was just trying to figure out how much in FTEs as opposed to dollars. And because you could extract the labour costs of your contractors, I was wondering is, since you can extract the labour component, do you also have that information that told you what the FTE labour is? Or is it just a labour cost? Like, when you are invoiced do you just have a labour cost, there is no way for you to tell whether it was three people or one person, it's just a labour line in your invoice?

L. YEUNG: You are correct, we only have the labour cost but not the FTE from the contract services.

M. GARNER: So you have no way to do that. Okay. That's kind of what I expected, but I thought it was worth asking about. Thank you very much, Panel. Those are my questions. Mr. Harper is here, he may have questions of his own, maybe I will just check.

EXAMINATION BY B. HARPER

B. HARPER: Yes. My name is Bill Harper, I am also a consultant for VECC. And I don't have a lot of questions so I anticipate being finished before the 3 o'clock break. If we can maybe go to VECC-69. This deals with net metering. Now, this interrogatory was assigned to both panels 2 and 3, so I will leave it to you to tell me if my question is best answered by the next panel as opposed to yourselves. And if we scroll down to part D. Here we asked if there were any incremental costs associated with net metering customers as opposed to customers without net metering, in the response you indicated that:

“With the automation of the billing process the incremental costs were minimal.” [As read.]

Now, as I understand net metering customers are injecting electricity into the Hydro Ottawa system and therefore require a bidirectional meter as opposed a normal meter which regular customers would require; is that correct?

T. FREEMAN: Yes, that is correct.

B. HARPER: And does this bidirectional meter -- I assume since it measures both ways costs more than a regular meter?

T. FREEMAN: That is a question that would have been better placed to our operational team on panel 1, unfortunately.

B. HARPER: Okay. Okay. Well, would you know whether -- okay. Maybe we will have to leave it there, because I was just wondering if it did cost more, whether it was the customer that paid for the cost or whether it was Hydro One that paid for the cost. That was my -- that was where I was going at the end of the day. And if that is something, Ms. Coban, you would feel comfortable sort of responding to as an undertaking, I leave it to yourselves.

D. COBAN: I think that would be best since we have missed the opportunity to ask panel 1 so we will just clarify.

B. HARPER: Sorry, panel assignments and stuff, it's hard to figure out which way you should be going.

D. COBAN: That's okay. That is why we have undertakings we can deal with that, thank you.

B. HARPER: And I guess -- unfortunately my next question is related -- is probably going to give me the same answer --

J. NOWICKI: Sorry, Mr. Harper. Before --

B. HARPER: If you could roll it in.

J. NOWICKI: Sorry, Mr. Harper. Before we proceed can we just mark that undertaking before we forget? That's JT2.14. Thank you.

T. FREEMAN: To clarify that undertaking, we will provide you with the cost difference between a non-bidirectional meter and a bidirectional meter; is that correct?

B. HARPER: Right. And, if there is a cost, who pays for the cost?

T. FREEMAN: Got you, okay. Thank you.

UNDERTAKING JT2.14: Provide the cost difference between non-bidirectional and bidirectional meters and who pays the cost difference

B. HARPER: As I said, I think my next question may fall under the same umbrella. Because I was wondering whether there were any incremental investments that Hydro Ottawa had to make typically in order to ensure that this injection of electricity into its system didn't impact either the reliable or the safe operation of the system?

T. FREEMAN: Again, that would be a question for our operations team, that was on panel 1.

B. HARPER: Would it possible just to include that under the same umbrella IR, Ms. Coban?

D. COBAN: We will consider it and if we can provide you an answer we will, and if not we will explain why.

B. HARPER: Okay, fine. Now, if we scroll up to part A of that interrogatory response, it indicates here that as of June 30, 2025 you had 601 net metering customers. And I was wondering, can you tell me how many of those were residential customers as opposed to general service customers? Because I understand net metering is both for residential and commercial customers. So I was wonder if you had a breakdown of that between residential and what general service type customers?

T. FREEMAN: I think we can provide that to you in an undertaking.

B. HARPER: Okay. That would be very useful, thank you very much.

J. NOWICKI: That will be JT2.15.

UNDERTAKING JT2.15: Provide a breakdown of residential versus general service net metering customers as of June 30, 2025

B. HARPER: Now, can we now turn to Schedule 634, and it will be page 4. I think it's that paragraph right there in the middle is the one I think you have got. Now, here you state that while the plan had been to automate the billing process for net metering customers the commercial net metering customers are still being billed on a manual basis; is that correct?

T. FREEMAN: Yes, that is correct.

B. HARPER: Now, maybe you could first of all just tell me: When did you move the residential customers over from sort of manual billing to automated billing when it comes to these net metering customers?

T. FREEMAN: I believe that project started in 2022 and continued to 2023.

B. HARPER: So it would be sometime in 2022 is when they were moved over, then?

T. FREEMAN: Subject to check, yes, that is correct.

B. HARPER: Okay. Well, I will leave it as a subject to check and you can get back if it's different. Now, do you know what your current plans are as to when or if you plan on implementing automated billing for your commercial customers?

T. FREEMAN: We have not included in this current investment plan automating our commercial net metering for our commercial customers.

B. HARPER: Okay. And do you have any idea what it costs, say, per customer, per net meter customer, per month to do your manual billing of a net metering commercial customer? And if not off the top of your head maybe I can take you to an IR response and we can work through that if it isn't something that's readily available to you.

T. FREEMAN: Sure, let's do that.

B. HARPER: So, if we could go to -- and I think it was on Monday you filed an attachment to SEC-27, it's attachment SEC-27A.

T. FREEMAN: That's correct.

B. HARPER: And maybe we can open that up. And actually you're right at the top, because if you look at the first few line there that is dealing with the net metring automation and the productivity benefits. Now, if I look at lines 5 and 6, it shows there the volume of it automated tiered bills and the volume of automated TOU bills. Now, are those volume numbers there -- are they assuming just the residential customers have been automated?

T. FREEMAN: Those are specific to residential customers, yes.

B. HARPER: Right, okay. And if I do the -- there is two types of customers. If I do the division I get roughly $367 a bill if it's tier, or about $95 a bill if it's automated. The 95 is pretty easy because it takes an hour at $95 an hour. So, would it be fair to say that sort of for commercial -- manual billing of commercial customers, say for 2026, costs are going to be somewhere between $30 and $95 depending on whether they are tiered or TOU?

T. FREEMAN: The residential bill structure is quite a bit different than the commercial bill structure, so I don't think you could compare the two in terms of level of effort. It wouldn't be a fair comparison.

B. HARPER: And in general if it -- is it more complex? So the number would be higher; or less come complex so the number would be lower?

T. FREEMAN: It would typically be more complex, but I can't speak to the specific number of what it would be.

B. HARPER: Okay. Well, I think I can leave it at that for now and that should be fine. Okay. Now, my last question, and actually I am not too sure if you can help me at all with this, or maybe this is probably more a panel 3 question. I was reviewing the documentation regarding Ontario's net metering program and I could not find any reference to there being a specific limit as to the size of the customers' generation, where it was at a certain size of generation the customer is not eligible to participate or has to be over a certain size limit; is that your understanding as well, or is this a better panel 3 question?

T. FREEMAN: I think that would be better placed to panel 3.

B. HARPER: Okay, fine. And I think, just checking my notes here, I think that's all the questions I had as well. Thank you very much.

D. COBAN: Ms. Nowicki, before we sign off I just wanted to confirm your undertaking number, I think I heard you say JT2.16 for the last one but by my records here we are at JT2.15.

J. NOWICKI: It is JT2.15.

D. COBAN: Okay, perfect. Thank you.

J. NOWICKI: Okay, no problem. Thank you, Mr. Garner and Mr. Harper. Up next we have SEC. Mr. Rubenstein or Ms. Scott?

EXAMINATION BY J. SCOTT

J. SCOTT: Actually, it's Jane Scott from the School Energy Coalition. I am going to go first and then hand it over to my colleague Mr. Rubenstein. Good afternoon, Panel. As I said, I am a consultant with the School Energy Coalition. My first question is related to 1-SEC-6, but I think what the best thing to pull up, because it refers to it in the response to that, is attachment 1-2-3A, which is the corporate budget memo.

And if you could scroll down, I think it's the second page at the -- well, maybe -- no, sorry, it's that last paragraph on the first page, and needing to consider focus on preferences, productivity, continuous improvement. So in that context, the answer to one of our other questions, but you don't need to pull it up, which was 4-SEC-67, states that the 2026 OM&A budget amount of 140 million was set with assumptions of embedded productivity of 3.4 million, corresponding to a reduction of 2.3 percent. So was that specifically communicated to the departments, those numbers, as opposed to just a general keep productivity, efficiency in mind?

A. COLLIER: Hi, Ms. Scott, it's Angela Collier. So SEC 67 is a question for panel 3, in terms of how rate framework and all that is working together. But I can confirm that, with respect to the budget memo that you have on the screen here, there was no specific targets, it was just a general guidance that was issued to everybody.

J. SCOTT: Okay. And I will ask that of panel 3. But I guess what I am trying to get at is, were the budgets developed and then reduced by 2.3, or were they told to develop them keeping that in mind?

A. COLLIER: The budgets -- the embedded productivity, which I think is really what your question is getting at --

J. SCOTT: Specifically in 2026, yes.

A. COLLIER: Yes. The embedded productivity, each business unit developed their budgets with those embedded productivity initiatives in mind. However, having said that, if you look at the material that we attached to CCC 13, I think, the rate app material, you will notice that the OM&A budget was originally 160 million instead of 140 million. So some of those new productivity initiatives came out of also that reduction generally to push the OM&A budget down.

J. SCOTT: Okay. And we do have a list of how that 3.4 million is arrived at. If we can go to, actually, 1 SEC 24, Table D, because I do have a question about that. So maybe you can just explain a bit to me how this table works. So for example, fleet pooling, how I read this is that this is a new initiative in 2026, and as a result of doing it there will be a 100K saving, and I guess this goes back to the previous question, a saving from what it would have been had we didn't do the fleet pooling; am I correct in that?

A. COLLIER: Yes, that's correct.

J. SCOTT: And 2027 is an additional .1 or the same -- the same related -- does something else happen then to increase the savings?

A. COLLIER: So how I would characterize this, Ms. Scott, is our fleet pooling initiative, which I believe was Mr. Garner that mentioned it before, is a reduction of the number of new vehicles that we're requesting, right, so we reduced it by 21 vehicles. So the OM&A savings that you see here in relation to those 21 vehicles is less fuel, less maintenance, offset by some software costs that we're introducing to pilot this. So it's fuel savings every year, it's maintenance saving every year, right? Those items are associated every year with those vehicles, they are not one time.

J. SCOTT: Right. And for example, in the next one, the cable locates, the savings from '21 to '25, am I correct in assuming that they have been incorporated into the budget? Carried forward into 2026?

L. YEUNG: Good afternoon, Ms. Scott. This is Louisa Yeung. So the savings you see in each year for cable locates, that represent the savings in that particular year.

J. SCOTT: Right. But when we get to 2026 we are sort of doing a reset; right?

L. YEUNG: We are doing resets, but they're not -- in each year you can still contribute us from saving us from doing, paying these locates field calls, so that is a saving in the year.

J. SCOTT: Okay. But it's not a new initiative? It's the continuation of an existing initiative; is that right?

L. YEUNG: That is the initiative introduced in the '21 to '25 period. Correct.

J. SCOTT: Okay. Okay, thank you.

For SEC 66A -- and I don't know if you have to pull it up, but this is where we asked for data -- well, actually, yes, if you could pull it up, we asked for data to the end of June for 2025, and you did provide that. But when we asked if there was a forecast, did you have an updated forecast, I think it says that that won't -- yes, there we go, an updated forecast will not be available until October 2025. Would that be available when you are going -- by the time you are required to file undertakings?

L. YEUNG: So the forecast information will be subject to our board of directors' approval, and our next board of director meetings, it has been scheduled October the 2nd.

J. SCOTT: So I think the undertakings are due on the 6th, if I am correct. So you would be able to provide, then, what the forecast is for 2025?

L. YEUNG: Correct.

J. SCOTT: Okay. I know this IR is just for the OM&A, but I know there is a number of instances where the same question is asked, so if they could be provided, you know. I think -- I certainly think there is one for a capital update. I am sure other intervenors might appreciate getting that as well.

J. NOWICKI: So can we mark that as an undertaking?

J. SCOTT: If you could.

J. NOWICKI: Yeah, that will be JT2.16.

UNDERTAKING JT2.16: Provide updated forecast

J. SCOTT: And if you go down, scroll down a bit on this one, we asked for an update on 2K, and you said you couldn't provide it. But you did provide the numbers. And as I understand, and I am not sure -- maybe -- well it's one of -- I don't have it in front of me, but if you look at 2K, the updated one that was attached to 1-SEC – or 1-Staff 1, sorry, 1-STAFF-1.

So 2025 -- right, this is FTEs, right? So –- okay, this has changed -- maybe it's not. I guess there is somewhere in one of the answers to an IR, it says that you have hired -- in 2025, you have hired 28 FTEs.

My understanding is there's no new positions in 2025, so that those 28 were filling, if you could confirm, are filling existing vacancies?

D. BURNETT VACHON: That is correct.

J. SCOTT: Okay. Thank you.

I guess the best place to start is 4-STAFF-173. This is about corporate cost allocations and the effect of the two storms and the strike, on them. I am just at the – sorry, right at the beginning, (a). The increase in $1 million in 2022 and $1.4 million in 2023, and the explanation is that these - this was a result of more corporate cost allocation because more supervision, more communications was required.

And then my understanding is in the answer to the -- later on in this question, though you say that because of the evolving, changing regulatory landscape, those costs are going to continue. Is that correct?

A. COLLIER: That is correct.

J. SCOTT: So I am trying to reconcile that, then, to 4-SEC-70. First of all, if you look at table A, so you go down, yeah, table -- keep going. Yeah, there, table A. So those corporate costs would be included in incremental labour costs? I am just trying to determine where would those corporate costs be included in the cost of the strike?

L. YEUNG: Hi, Ms. Scott. So the answer is they will not be included in this table A. This table A is the direct cost related to the labour strike.

J. SCOTT: Okay. So then I go to 412, exhibit 412, table 2. Yes. So my understanding is -- how this question came about is we have the $8 million in 2022 for a storm, we have the $8 million in 2023 and we have the $6 million for the labour.

So we asked about why the reversals, why those costs were not totally reversed, and was given the answer that there were increases in other areas. And if you go back to -- so you are saying on this, for 2022, the increase in corporate costs were not included in that $8 million. They were included where, in that column, for 2022?

L. YEUNG: Sorry, can you repeat your answer, please? Sorry, your question, please?

J. SCOTT: Yeah. We are trying to get an idea of were all of the costs of the two storms and the strike reversed. And the answer in 4-SEC-70 was no, there were increases in other areas, so here is the net, the 6 and the 7 credit.

But what of the costs that increased as a result of the strike was - and the storms - was as corporate allocation? So I am trying to identify where that comes into play. I thought it was part of your $8 million, $8 million and your $6 million. But now you're saying no, it's not.

L. YEUNG: Can you give me one second, please, I just need to confer.

J. SCOTT: Okay.

L. YEUNG: Sorry about that. So that cost is included in other costs. So the Table 2 in exhibit 42, that the idea is to show the cost drivers year over year to explain the major cost drivers starting from the inflation.

J. SCOTT: Well, sorry, before you go on: If you look 4-SEC-70, table B, so - and that's your other costs, the 5.5 credit. So from this table, how I read this table, is that the 7.7 – okay. Now, you are saying that does not include the corporate allocations. Right?

L. YEUNG: So I just wanted to clarify that the corporate allocation is not included in the major weather events calls, because the major weather events calls are trying to capture, the some reservation costs, the direct costs in there.

J. SCOTT: So then I go back to Table 2 and say, you know, it's -- so this was -- this is a million dollar increase from 2021 to 2022 in corporate cost allocations. So my understanding, it's not inflation, it's not COVID impact, it's not a new IT program. Is it included in the other costs, then, is what you're saying?

L. YEUNG: So, maybe a better way to explain it is to take a look of CCC-49, that will show a view of that cost year over year change. That is in Table A, the first line. So meaning that the costs are not reversing out, that one million.

J. SCOTT: Right.

L. YEUNG: So, yeah, we had major weather events in 2022. In 2023, we also have more weather events. We have the April ice storm, and then in the summer we have a lot of lightning storms, as well, and also the labour strike.

J. SCOTT: Right, right. But that and, as I read the answer to 4-STAFF-173 which you don't have to pull up, on that first line the 4 million to the 5 million, that 1 million increase was a result of the weather event. And the additional to the next year, 1.4 million, was a result of the weather event and the strike. And so, what you're saying is those costs were not reversed, they are continuing; correct?

L. YEUNG: Correct, they are continuing.

J. SCOTT: Okay. So, and when I look at 2N, corporate cost allocations, and we don't have to pull it up but they appear to be in sort of three major areas, corporate communications, finance, internal audit, risk management, and the board of directors. So, can you explain, and I know there has been a high level well evolving, but what specifically in those three areas, what has increased that needed to continue with a 2.4, I guess, total increase in allocations? And specific, I mean one area, you know, like board of directors; are there that many more meetings that it's increased 400K?

A. COLLIER: Sorry, I didn't realize I was on mute. Can we maybe pull up the exhibit that you're looking at, Ms. Scott? Is it 2N you said?

J. SCOTT: 2N, yeah, yeah. But you have to look at 2021's corporate allocations and compare 2022 corporate allocations to it, which is kind of hard to do. But we go down a bit further. Yes, so that's 2021 totalling the 4 million. And if you go down to the next, 2022, corporate allocations totalling to the 5 million and if you compare each of those headings, you'll see that -- well, as I did it for both years but corporate communications totals 1.1, finance internal audit risk management 0.6, and board of directors 0.4 increase from 2021. That's from 2021 to 2023.

A. COLLIER: If maybe we can take them one at a time, just to make sure I am following?

J. SCOTT: Well, okay. We'll go if --

A. COLLIER: So, let's take board of directors.

J. SCOTT: Okay. So, in 2023 it's -- sorry you have to go down another.

A. COLLIER: You're comparing '23 to '22?

J. SCOTT: No, to '21, so that you capture the increases in 2022 and 2023.

A. COLLIER: Okay. So, '23 to '21?

J. SCOTT: Yeah, so 465, 466K. We go up to 2021, it's 37K.

A. COLLIER: Just let me confer for a second. Sorry, Ms. Scott. What I would say is the board of director cost, you can see from the cost allocation that it was 10 per cent in 2021 and it's 69 per cent in 2023. That really had to do with a correction from that time. So it's not more meetings, it was just an incorrect allocation.

J. SCOTT: Okay. So it isn't really attributable to the weather events and the strike in that case?

A. COLLIER: No, I mean, if we look at -- if I take you to CCC-57 and we look at some of the allocations here. Like, if we look at customer service and corporate communications you can see the increase going from 46 per cent -- sorry, I just want to make sure, Table A, is up on the screen. Yeah. So, if you look at middle of the page you will see customer service and corporate communications, you will see it increasing from 46 to 80. That has to do with some major weather events and the strike. But --

J. SCOTT: But, okay.

A. COLLIER: -- each line item might have a different situation.

J. SCOTT: But from the answer to 4-STAFF-173, a million dollars of that is the strike and in 2022 is the strike and the weather events? I understand what you're saying here, and that reflects that, yes, there is more being allocated in customer service. And though I don't quite understand the finance one, but when you look at the actual dollars, that million dollar increase in corporate allocations, which according to 4-STAFF-173 is...

A. COLLIER: Yes, I think what we have said in 4-STAFF-173 is that those are the main drivers. So, if you look at the allocation -- no, Lianne, you can leave it on this Table A. If you look at the allocations for management services or customer service you'll see that change between '21, '22 and '23. And the main reason for those drivers were due to the derecho and then the strike, but then for other reasons as we have outlined it's continuing at that level.

J. SCOTT: Okay, thank you. 4-SEC-73, maybe not the best one to open. 4-CCC-52 is probably, because it refers there. This is about the vacancy rate. And then if you keep going down -- have I got the right one? Yeah, Table A. Yeah. So this was updated, and so my understanding is, so when you put in the -- originally the vacancy rate in 2024 was 10 percent, but when you updated the actuals it became 11 percent. This is -- I am comparing this to Table 10 in...

D. BURNETT VACHON: Yes, that is correct --

J. SCOTT: And --

D. BURNETT VACHON: -- 10 was the assumption, 11 was the actual.

J. SCOTT: Right. And for 2025 the assumption is 8 percent, but year-to-date has been 9 percent?

D. BURNETT VACHON: That's correct.

J. SCOTT: And you're still going with 8 percent for 2026?

D. BURNETT VACHON: We are.

J. SCOTT: Okay. And so this sort of builds on Mr. Garner's question, but if I understand how this is done, in 4-SEC-76, if I wanted to compare apples to apples and FTEs to FTEs, yeah, the reconciliation just down that Table A. No, that's not the one. The one that has your adjusted FTEs. Just go -- there. Okay. You have got -- well, the 75 -- which was the -- there is an IR where you explain -- you make an adjustment for the -- I thought it was SEC 76. Could you just scroll down a little bit further? No. For the strike you make an adjustment. Does this ring -- yeah, here it is. Yeah, it was in 4-CCC-52, so we were in the right one. Table A. Okay. So this other FTE adjustment, as I understand, is to adjust for the fact that the strike -- you didn't have the FTE hours. And so if -- am I correct that if I take the 624 before the adjustment -- I am trying to compare to the 641 in 2025. What is the increase in FTEs, '25 over '24? Is it the 641 minus the 624?

D. BURNETT VACHON: If I can just take a moment to confer?

J. SCOTT: Okay. Thank you.

J. NOWICKI: Ms. Scott, while the panel is conferring, we are approaching the time for the afternoon break, so if you have a natural stopping point within your questions, that would be very helpful.

J. SCOTT: I do have a few more, so probably after this question would be a good time to stop.

J. NOWICKI: Okay, thank you.

J. SCOTT: Unless they want to confer over the break and we can pick it up.

J. NOWICKI: Okay, we will see when the panel returns.

J. SCOTT: Okay.

D. BURNETT VACHON: My apologies. So two things. Actually, I think to get at what you're looking for, I would actually take you to our evidence, because there is a couple of factors in that table that confused the situation. But if we go to our evidence, at Attachment 4-1-3A -- and Lianne, that's on page 12. You can see number of employees at year end in Table 6. Does that give you what you're looking for, Ms. Scott?

J. SCOTT: But that's not the actual -- that's not the updated 2024 actuals; right?

D. BURNETT VACHON: No, these are still the test year.

J. SCOTT: Okay. I mean, if you can update that with the actuals for 2024 and then -- and also provide where we are as of year-to-date -- well, yeah.

D. BURNETT VACHON: Yes, I can do that, I can update Table 6 to show the 2024 actuals and the year-to-date 2025 actuals.

J. SCOTT: Okay.

J. NOWICKI: So that will be JT2.17.

UNDERTAKING JT2.17: Update Table 6 to show 2024 actuals and year-to-date 2025 actuals

J. SCOTT: Okay. I think -- I am going to think about that over the break, and I just might have a follow-up on it, but I think Ms. Nowicki wants to have a break at this point.

J. NOWICKI: Thank you, Ms. Scott. So it is 3:31. We will come back at 3:46.

J. SCOTT: Thank you.

--- Recess taken at 3:31 p.m.

--- Upon resuming at 3:46 p.m.

J. NOWICKI: Ms. Scott, please continue with your questions.

J. SCOTT: Thank you. I looked at that Table 6 and, from what I can understand, this is 413, attachment A, table 6, that this is neither positions nor FTEs; it's actual bodies at the end of the year. Is that correct?

D. BURNETT VACHON: That is our number of employees at the end of the year, and it's made up of full time, temporary and part time.

J. SCOTT: Right. So that's not really what I am looking for. So if I go back to the 4-CCC-52, what I am trying to see is what -– so, in 2026, the increase in positions is forecast to be 81, but the increase in FTEs is forecast to be 75. I am trying to get comparables in the previous years. And I understand that the strike sort of plays havoc with that, but my understanding is that's what the FTE adjustment is supposed to do.

So if I look at it, can I compare the 641 in 2025 to the 624? Or do I compare it to 624, plus six?

D. BURNETT VACHON: If I understand your question correctly, you could compare the 641 to the 624; you will see that the vacancy assumption is different between those years. So that might be what's causing that difference.

J. SCOTT: Okay. So the increase from, in this chart the increase is 17 FTEs from 2024 to 2025, and – I mean, then in 2023 to 2024, it gets as bit crazy; it becomes 130, then.

D. BURNETT VACHON: That is correct. There was an IR where we attempted to give a normalized number to help make that easier. It's not perfect, but I can refer you to SEC-76, I believe. Let me just pull that up.

J. SCOTT: But this has not been updated in 2024 for the new actuals. Right?

D. BURNETT VACHON: No, but --

J. SCOTT: It may be – no, go ahead.

D. BURNETT VACHON: I was just going to say, in the paragraph above you will see where we attempted to give a normalized FTE number for 2023. I am sure that will help.

J. SCOTT: Okay. But these are the same, the 494, is the same in 2023. This column here is the same. The 2023 column is the same as - again, it's difficult because of the strike. And maybe just for now, I just want to focus on 2024.

When you update it in 4-CCC-52, what is the adjustment in 2024? The six?

L. YEUNG: Ms. Scott, if I may, can I bring you to CCC-52 which we have the year-end 2024 positions of 657? That is our year-end actual positions.

J. SCOTT: Yes. Ms. Yeung, I am not really interested in the year-end positions. It's more the relationship between positions to FTEs, and increase in positions versus increase in FTEs, that I am looking for.

So if someone can explain what the six – I mean, if you tell me that 624 compared to 641 is comparable, that's apples to apples, then I will use those numbers.

D. BURNETT VACHON: Yes. Yes, I would say that's correct.

J. SCOTT: Okay. So I think you can eliminate that undertaking about updating the year-end number of employees, or updating the updating 2024 number of employees. So that last undertaking...

J. NOWICKI: Just to confirm, that's JT2.17 that is no longer needed?

J. SCOTT: Yes, yes.

J. NOWICKI: Okay. Thank you.

J. SCOTT: Okay. Thank you, I just have a couple more.

At 4-SEC-74, we asked about forecasted overtime. But I think the answer refers to 4-CCC-52, so, sorry – (b).

Yes, and it talks about recent trends, excluding outlier years. And you do provide, the actual overtime is provided in 2-CCC-52(a), which you don't have to open up. But it's not clear to me which outliers were not considered and what exactly the trend that is being followed in.

So we were wondering, can you provide us with the calculations as an undertaking?

L. YEUNG: Hi, Ms. Scott. So the overtime is budgeted based on recent trends. The outlying or that we exclude them is to deal with the strike and the major weather events, so meaning that we don't budget that level of overtime again to happen, from the labour strike and the major weather events.

J. SCOTT: So can we see what numbers you are using to get the trend, the adjusted numbers, or the -– like, I don't know. Did you just exclude 2022 and 2023, altogether? Or just the hours that were for the storms and for the…

L. YEUNG: So maybe I should bring up that Excel attachment --

J. SCOTT: Mm-hmm.

L. YEUNG: …in CCC-52(a). So perhaps this will provide a better view on our overtime. We have overtime in different categories. So that you can see that, such as row 19, the $2.766 million, that is to do with the major event in that year. And the labour strike is not being forecasted for, in the future years.

J. SCOTT: Right. So is that the same? So at line 24, are you removing the five -- where did I see it? -- $5 million, or only a part thereof? Or?

L. YEUNG: Correct. The $5 million in 2022 is - it has a lot to do with our major weather event in that year. So, as you can see that, it has been normalized and not assumed to continue in the future years.

J. SCOTT: Sorry, is this number the normalized number? Or is this the actual number?

L. YEUNG: So the $5 million, sorry, it's actual 2022.

J. SCOTT: Okay.

L. YEUNG: And in 2025 bridge year, we did not budget for $5 million, that level.

J. SCOTT: Right.

L. YEUNG: It is down to $3.58 million.

J. SCOTT: So what I am asking for is can you -- I can't tell what -- I understand 2022. The 2023 looks like it's in line, but you are saying there's hours in there for the storm and the strike. If you could just show the normalized numbers for 2021, '2, '3, '4 and if that's the trend that you used?

L. YEUNG: It will be very difficult to show the normalized each year that our budget assumption that we do based on some historical trends. So, meaning that some of the smaller events, it would still be part of the historical trend but only exclude certain major events such as the derecho storm, the labour strike, those we exclude them to do the budget. So the budget will be a fair representation of the normalized over time, and then we factor in that also that the labour costs increase year over year, so which is part of the budget assumptions.

J. SCOTT: Okay. But do you have a calculation, I guess, is my question; or is it just done, sort of eyeballing it?

L. YEUNG: We don't have a calculation. How we do it is we look at each of the business area and to take a look at the trend, what the over time is like.

J. SCOTT: Okay. Second last question, 4-STAFF-150E. And in that asked about the five new positions in IT in 2026. So my question is this all new work?

A. WILLIS: Hi, Ms. Scott. It's Andrew Willis.

J. SCOTT: Hello.

A. WILLIS: Yes, yes most of these positions are for new work in the IT space and to solve some of the problems.

J. SCOTT: And I understand the main driver is grid modernization? I think it says that in here somewhere.

A. WILLIS: The IT positions as it relates to information management and technology, and I will direct you -- a nice view of this would be in 4-Staff-159.

J. SCOTT: Yeah, I am looking at it right now, yeah.

A. WILLIS: Yeah. So, for information management and technology we need more cloud engineers because we don't have those skill sets inhouse. Cyber security is an ever-increasing problem for many companies and we certainly need to have the right skill sets inhouse. We are taking on more critical projects, technology projects especially, as you mentioned, with grid modernization so program management skills. So hopefully that helped answer some of your questions.

J. SCOTT: Do you have any measure of the volume of work for these positions? I mean, you did say it's new work so you can't compare it, so you may not, but...

A. WILLIS: With grid modernization we are going to see more IP enabled assets on our grid, we are going to be putting in new technology systems, we met as a leadership team and we decided that these roles were absolutely required to ensure Hydro Ottawa's success, as well as to, you know, safeguard Hydro Ottawa's systems.

J. SCOTT: Okay. When I look at 159 on the table I see one of them is a manager and one is a supervisor. For those two positions could you provide the number and titles of the direct reports, and if there's people under that level, numbers as well for that?

A. WILLIS: We can certainly provide that.

J. SCOTT: Okay, thank you.

J. NOWICKI: That will be JT2.17(sic).

UNDERTAKING JT2.17(sic): Provide number and titles of the direct reports for IT manager and supervisor and numbers for level below

J. SCOTT: And my last question is 4-STAFF-151, same sort of question. There's four new positions in safety, environment, and business continuity. I don't think any of those are managers or supervisors, but is this all, again, new work? I.e. not -- when I say "new" it's work that's not being done at the current time.

D. BURNETT VACHON: So, I can speak to the business continuity for sure. That is work that is new, those are new roles that we have not had previously, so the manager of business continuity.

J. SCOTT: Oh, that is a manager position?

D. BURNETT VACHON: It is, I believe in there we say -- yeah, manager business continuity management, as well as business continuity specialist.

J. SCOTT: Okay, if there is -- oh, I see, yes. Sorry. But I am just -- sorry, I am only looking at 2026 so.

D. BURNETT VACHON: Oh, sorry.

J. SCOTT: You don't -- I won't give you an undertaking there for those ones.

D. BURNETT VACHON: Okay. So, sorry. In '26 it's a business continuity specialist and an instructional designer. We do currently have an instructional designer, but given the increase in training that we are expecting with new employees, we are expecting to have considerably more work to be done.

J. SCOTT: So that second instructional designer is related to the, as you said, the increase -- the 81 positions or 80 positions that are being hired?

D. BURNETT VACHON: That is correct, and the anticipated increase in training.

J. SCOTT: Okay. Okay. I think that's all my questions for this panel. I will turn it over to my colleague Mark Rubenstein. Thank you. Thank you, Panel.

J. NOWICKI: Mr. Rubenstein, before you proceed I just want to note that we are approaching time for SEC, so there is about five minutes left for your allotted time.

M. RUBENSTEIN: Well, I think I have a number of questions quite above -- or, actually, above schedule so I would ask for the indulgence. I just have a few interrogatories to go through.

J. NOWICKI: Okay, please proceed.

EXAMINATION BY M. RUBENSTEIN

M. RUBENSTEIN: Good afternoon, Panel. Can we first start at 1-SEC-22? And, Panel, this interrogatory relates to Gartner enterprise IT spending and staff benchmarking study. And, as I understand, Hydro Ottawa is relying on this study to confirm that its IT strategy and investments are reasonable; is that a fair summary of what the reliance on the benchmarking study?

A. WILLIS: Yes, that's correct. We have leveraged Gartner in the past, similar to many other utilities, to analyze that information.

M. RUBENSTEIN: All right. And we had asked you in part A to provide the list of companies in the peer group and in the ITKMD utilities, utilities group, and in the response you have refused to provide this information, as I understand, based on Gartner's confidentiality agreement that it cannot release those names; do I have that correct?

A. WILLIS: It is, Gartner's clients are confidential and we do not have access to those.

M. RUBENSTEIN: Did you ask Gartner or is this just your assumption they wouldn't provide it?

A. WILLIS: This was communicated at the time of engagement that they would not be able to disclose the list of clients.

M. RUBENSTEIN: All right. And you still moved forward with the benchmarking study even though you -- even though even you wouldn't know who the comparators would be?

A. WILLIS: We know that utilities that they have included in their list, I believe that's under question (b), but they are more than purely distribution organizations and we did elect to proceed with them.

M. RUBENSTEIN: Sorry, you just said you knew the companies in the list, but I -- you don't know the companies in the list?

A. WILLIS: Sorry, the types of companies. Distribution utilities, transmission utilities, we know the types of the companies but we do not know the clients themselves.

M. RUBENSTEIN: All right. And in part B we had asked you to break down both the peer groups into various categories of companies, you can see that in the question, distribution-only utilities, transmission-only utilities, generation-only utilities, distribution and transmission-only utilities and other, and you did that for the peer group, the smaller peer group, but not for the larger ITKMD list. And I think your response was, well, that would be a considerable effort to analyze the nature of operations for each group; do I understand that?

A. WILLIS: Yes, that was Gartner's response to Hydro Ottawa.

M. RUBENSTEIN: Okay. And so did you ask them to then and they just said it's too much work or they refused or they -- can you just help me?

A. WILLIS: They had made it clear that it was very difficult to provide that information. We went with their recommendation.

M. RUBENSTEIN: Okay. So we don't know the names of the companies, and you as well as Gartner are not providing the breakdown of where those companies -- or the specific type of utility organization; correct?

A. WILLIS: Correct.

M. RUBENSTEIN: And as I understand it, part D, we asked you to provide some information with respect to the peer group utilities to show IT spend as a percentage of distribution revenue only, and you didn't do that; do I have that correct?

A. WILLIS: The reason we were not able to obtain that information from Gartner is that they do not have -- they do not have -- the minimum number of organizations required in the group is seven, and they do not have seven distribution-only groups, so we were not able to get that information from what we heard from Gartner.

M. RUBENSTEIN: Sorry, that they thought it was -- I just want to be clear. Is it that they wouldn't do it, or that they thought it, you know, creates too small of a sample size?

A. WILLIS: The only information we received is that they -- they don't have the information in their systems to be able to come up with the dimension you are looking for.

M. RUBENSTEIN: Okay. And just so I am clear, in the categorization that -- in part B that we had asked you, Hydro Ottawa fits into the distribution-only utility; correct?

A. WILLIS: Correct.

M. RUBENSTEIN: Okay, thank you very much.

Can I ask you now to go to 2-SEC-33A. It's an Excel spreadsheet is the attachment. Sorry, by A I meant in brackets (a), the attachment. And so in this table we had asked you and you provided Appendix 2AA on an in-service additions basis. Can I ask you to provide a revised version of this table that shows in-service additions by program on a net basis, so instead of showing it on a gross basis and then have a single line item for category -- that shows the capital additions, it simply shows each of the programs per category on a net basis?

L. YEUNG: Hi, this is Louisa Yeung. Yes, we can.

M. RUBENSTEIN: Thank you very much.

J. NOWICKI: That would be JT2.18.

UNDERTAKING JT2.18: Provide revised version of table showing in-service additions by program on a net basis. Show each programs per category on a net basis instead of showing a gross basis with a single line item showing capital additions

M. RUBENSTEIN: And in your response -- you can just add it to that -- I would ask if you could explain what is the driver -- in the system access category, there is a spike, significant spike, in additions, in 2027, that appears to be driven by the system expansion, but it's not clear to me what programs or what's driving that, so if in the response -- and I know that's somewhat your category, but somewhat panel 1 -- if you could explain that? Is that something that can be done?

L. YEUNG: So you are asking us to explain the spike in 2027 in system service; am I correct?

M. RUBENSTEIN: No, system access. You can see it's --

L. YEUNG: Oh, sorry, system access.

M. RUBENSTEIN: -- system in 17 there is quite a spike in the additions on the net basis? It appears that it's being driven by line 10, the system expansion, but if you go through the evidence in expansion it doesn't really explain what projects or why that -- why you are seeing on an additions basis such a significant spike in 2027.

L. YEUNG: Right, we can provide that.

M. RUBENSTEIN: Thank you very much.

L. YEUNG: No problem.

J. NOWICKI: That will be JT2.19.

UNDERTAKING JT2.19: Explain system access spike in 2027

M. RUBENSTEIN: Can I now ask about 1-SEC-24. This is the updated undertaking that I think you provided, if there is an updated version of this which was provided yesterday morning. And here you are showing some updated tables showing the annual productivity savings broken down into the categories you have, which is on a CAPEX, a depreciation in OM&A, and a third party. And as I go through that, when I look at the various initiatives that show savings beginning in 2026, I get the following initiatives: Fleet pooling, net metering automation, and satellite image for vegetation management. Do I take it then that all those -- so let me stop for a second. I had assumed coming into the discussion that those were all initiatives that were beginning in 2026, but I take it from some of the discussion I've heard today that at least the net metering automation is actually already underway, has been implemented. Do I have that right?

T. FREEMAN: That's correct. Net metering automation was in 2022. The reason there is no savings identified is because there were no net saving when the capital depreciation cost was factored in, it was not identified as savings during the previous rate period, it is only showing as savings moving forward.

M. RUBENSTEIN: Was there a net cost during that period?

T. FREEMAN: There was a cost to the implementation. The savings started at the same time. I don't have a net in front of me at the moment.

M. RUBENSTEIN: Would there be a -- let me put it this way. Would there be an annual material net cost?

T. FREEMAN: Just allow me to confer for one moment, please. Thank you, Mr. Rubenstein. The answer would be, no, there was no material net cost or savings.

M. RUBENSTEIN: Now, fleet pooling, has that been implemented yet?

A. COLLIER: Not yet.

M. RUBENSTEIN: And when is that expected to be implemented?

A. COLLIER: We are expecting to start implementation in 2026. There is 17 vehicles that we will not purchase in 2026, and the remainder in 2028, but we are waiting for the upgrade of a system which is expected 20 be finalized in Q4 of this year.

M. RUBENSTEIN: And as I understand from reading the evidence, it's labelled often as a pilot project. I just want to understand what that means. Is it only then being implemented in a subset of the company or a subset of operations?

A. COLLIER: It's labelled as a -- I mean, we do pool vehicles today, but it is primarily within same location or same work group or same kind of work unit. This is an expansion of that program. We are leaving it as pilot because we do want to push it further. There is quite a bit of change management and changing behaviour that we have to figure out along with the new software, so that's really why we have it a pilot. I don't imagine we would cancel the program, though.

M. RUBENSTEIN: Well, let me go in the opposite direction. Assuming this all is a success, can it be expanded --

A. COLLIER: I think that will have to be analyzed.

M. RUBENSTEIN: Well, but let me -- let me rephrase it. Could it be technically expanded? So, for example, if you're only doing this on a subset of the company, you could potentially do it to a larger segment. I am just trying to understand what is not being done here.

A. COLLIER: I would say it could technically be expanded, you are correct to say that, but to what extent I think is the piece that would have to be analyzed. Obviously, we need to make sure all of our staff have the vehicles they need to do the work at the time they need to do it. So we cannot, like, reduce to an extent where that would be problematic in the event of a major outage or a storm. So we are starting with, you know, a fairly enhanced scope with this reduction of 21 vehicles. It will kind of stretch the teams to make sure that they are scheduling their work properly and whatnot, but expansion beyond that, we would really have to analyze the data. I couldn't really speak to how much further we could expand it at this time.

M. RUBENSTEIN: Okay, thank you very much. And so am I correct, then, based on the discussion we have had and just had with respect to the net metering automation, that only fleet pooling and satellite image for vegetation management begin in 2026? All the others have already begun?

L. YEUNG: Sorry, can I have a moment? I just wanted to take a quick scan.

M. RUBENSTEIN: Sure.

L. YEUNG: You are correct. But I just wanted to make one correction in there: the satellite imaging vegetation management is in fact implemented within 2021 to 2025 time, but we are in a pilot. So we believe the saving is not going to mature until 2026.

M. RUBENSTEIN: Okay. Can I ask if any of the – and maybe we will have to do this by undertaking, are any of the initiatives that you have listed in the interrogatory, were any of them implemented before 2021? You may have to take this by way of undertaking, which is okay.

T. FREEMAN: So the one that would fall in that category would be online billing. Now there was obviously online billing prior to 2021, but efforts have been made and new customers have been brought on throughout the previous rate period and continuing into the next, which is why we are showing the savings there. But online billing did exist prior to 2021.

M. RUBENSTEIN: Sorry, so only online billing is the only one that was implemented before 2021? Did I hear that correctly?

T. FREEMAN: We also would have some remote disconnect meters prior to 2021, but it would be in the same category of the savings we are identifying throughout the previous rate period as we bring on more remote disconnect meters.

M. RUBENSTEIN: All right. Now I just want to be clear, is this only -- are you only speaking of the projects within this panel's expertise? Or is this comment generally to all of the difference in issues that may fall under “other.”

T. FREEMAN: We are speaking of projects within our expertise.

M. RUBENSTEIN: Okay. Well, can I ask you to do an undertaking to ensure that we have the complete picture of any -- of all the initiatives, which initiatives were implemented in whole or in part before 2021?

T. FREEMAN: Yes, we can do that.

J. NOWICKI: That will be JT2.20.

UNDERTAKING JT2.20: Provide a complete picture of initiatives implemented in whole or in part before 2021

M. RUBENSTEIN: And my last interrogatory, could we go to 1-SEC-28. And we had asked you with respect to the productivity scorecards, and I guess upon reflection I may have misunderstood something. And it sort of tweaked me by your response, where you say:

“Please find the 2021 actuals for the measures included in the corporate productivity scorecard.”

Do I take it, then the -- let me back up: Does the company have a corporate scorecard that differs from the productivity corporate scorecard?

A. COLLIER: Sorry, just a second, Mr. Rubenstein. We will be right back.

M. RUBENSTEIN: Sure.

A. COLLIER: Can you just repeat your question?

M. RUBENSTEIN: Sure. Does the company have a corporate scorecard that is separate from the productivity corporate scorecard?

A. COLLIER: At the holding company level, yes.

M. RUBENSTEIN: Can I ask you to provide a copy of the corporate scorecard for the years 2021 through 2025?

A. COLLIER: I think that's what has been provided, so it’s --

M. RUBENSTEIN: I think that is the productivity scorecard. That's why I --

A. COLLIER: I see, sorry. Okay, yeah.

J. NOWICKI: So that will be JT2.21.

UNDERTAKING JT2.21: Provide a copy of the corporate scorecard for the years 2021 through 2025

M. RUBENSTEIN: Thank you very much, panel, those are my questions. Thank you for your assistance.

A. COLLIER: Thank you.

J. NOWICKI: Thank you, Mr. Rubenstein. Up next on our schedule we have Environmental Defence. Is Environmental Defence here? Do they have any questions for panel 2?

So, not hearing anything, I will move on to our next intervenor, which is CCC and Mr. Gluck. Please go ahead.

EXAMINATION BY L. GLUCK

L. GLUCK: Good afternoon. My name is Lawrie Gluck, and I am a consultant for the Consumers Council of Canada. We can start with 1-CCC-1, part (f), please. Table A, please.

So in this table, Hydro Ottawa provided the inflation rates that are applied to the various asset types that form its investment plan for the 2026 to 2030 period.

Can you please advise what inflation rate was applied in 2025 for the five categories of assets that are listed in table A?

A. COLLIER: Mr. Gluck, I don't think we have that on the evidence on the record as of yet.

L. GLUCK: That's a thing that you can undertake to provide, please?

A. COLLIER: We can.

L. GLUCK: Thank you.

A. COLLIER: So just to confirm, it's a 2025 column being added to this table A?

L. GLUCK: It is.

A. COLLIER: Okay.

J. NOWICKI: So that will be JT2.22.

UNDERTAKING JT2.22: Advise the inflation rate applied in 2025 for the five categories of assets listed in 1 CCC-1, part (f), table A

L. GLUCK: And I think you may need an undertaking for this as well, if you are willing: Can you provide the equipment and materials’ dollar value for each year between 2024 and 2030 prior to the application of the inflation adjustments for each of the five categories of assets in this table?

A. COLLIER: The response to part (g), with the weighted average, does that not get at the same piece of it?

L. GLUCK: Is that a weighted-average inflation rate that you are discussing in part (g)? I thought that would have included everything. So maybe I am not understanding.

Is that the weighted average of just the materials and equipment? Or is that a weighted-average inflation rate, you know, across labour? I took it as it was everything, but if you are telling me it's equipment and materials…

A. COLLIER: No, no, you're correct; it is everything. Okay.

L. GLUCK: So can you provide that?

A. COLLIER: So you want table A in each of the categories, the dollar values of all equipment and materials for all years from '24 to 2030 uninflated?

L. GLUCK: Uninflated, and then the next part of it would be the same numbers inflated so I could see the difference between those numbers.

A. COLLIER: Yes, we can undertake to do that.

L. GLUCK: Thank you.

J. NOWICKI: That will be JT2.23.

UNDERTAKING JT 2.23: Provide dollar values of all equipment and materials for all years from '24 to 2030, inflated and uninflated

L. GLUCK: Thanks. If we can move to CCC-14 part F, please. And in this response Ottawa describes that for forecasting purposes it groups projects into two categories, those that are expected to be completed in a single year and others that are expected to be completed over multiple years. Can you help me to understand how you determine how to categorize these different projects? Or just a little bit more detail in terms of what exercise does Hydro Ottawa undertake to determine whether a given project will be completed in a year or over multiple years?

A. COLLIER: That information is provided by the representatives on panel 1 to finance. So I am not sure exactly I could speak to the process that they go through.

L. GLUCK: So, essentially based on that response it's the people involved in the projects --

A. COLLIER: Mm-hmm.

L. GLUCK: -- specifically advise whether they believe they are going to complete the project in a year or over multiple years, and then that feeds into how your -- how you forecast the budgets in the future?

A. COLLIER: Correct.

L. GLUCK: Okay. Well that's helpful, thank you. And in part G of this response, you describe that the enterprise asset management project presents an opportunity to enhance its assets' data, and in the context of forecasting in-service addition timing. Can you what additional functionality the EAM system would allow?

A. WILLIS: Hi, Mr. Gluck. It's Andrew Willis from IT. Today Hydro Ottawa does not have an enterprise asset management system and many of the processes are all manual. This relates to managing the lifecycle of assets, maintenance, workflow automations, how it ties into projects, it's been very manual and we know with grid modernization coming our assets are going to increase, so we are implementing that tool so that our business can scale and we can get more efficient as a company at managing our assets as a whole.

L. GLUCK: More specifically, with respect to, I guess it's financial forecasting, in terms of the timing of in-service addition, you provided this response to be in the context of a question that I asked about, you know, the ability to look at pooled assets and determine what month they go into service. And moving towards a more granular approach to forecasting and in-service timing; is that something that you expect the EAM system to provide?

A. COLLIER: I do. For example, our poles are considered a pooled asset today. I would hope that with the implementation of an EAM we can move away from that pooled asset approach and have it linked to our GIS and know at a granular level, both between multiple systems asset by asset.

L. GLUCK: Okay, thank you. And if we can go down to Table A, please. I think it's on the next page. And here is, basically, a listing of all the major discrete projects between 2021 and 2025, so the historical period. And what I did not ask in my IR, and I should have, is can you provide the in-service month for the actual column? You provided it for the planned column, but also for the actual column; is that possible?

A. COLLIER: Yes.

L. GLUCK: Thank you.

A. COLLIER: So just to clarify for the record, Table A of CCC-14, we will provide the actual in-service month.

L. GLUCK: That's correct, thank you.

J. NOWICKI: That will be JT2.24.

UNDERTAKING JT2.24: Provide actual in-service months for CCC-14, Table A

L. GLUCK: Thanks. If we can go to 2-CCC-15, attachment C, page 7, please. Now, perhaps it's page 8, sorry. Yes, thank you. So, with respect to the MyAccount redesign project, my understanding is that the project charter, which is attachment C that we are looking at, scopes Phase 1 of the project to be related to residential and small commercial customers; is that correct?

A. WILLIS: Correct.

L. GLUCK: Thank you. And was Phase 1 of this project completed based on the scope as outlined in the Charter?

A. WILLIS: Yes, it was.

L. GLUCK: Thank you. And the project goes an initial budget of $3.6 million, as you can see here, and I was wondering if you can provide final cost of the project, broken out between operational and capital costs as it was actually completed?

A. WILLIS: Yes, I believe we can provide that.

L. GLUCK: Thank you.

J. NOWICKI: That will be JT2.25.

UNDERTAKING JT2.25: Provide final costs of the MyAccount redesign project, broken out between operational and capital costs

L. GLUCK: And can we go to 4-CCC-36, part A, please. And here Table A shows the capitalized software costs and the related non-capitalized maintenance costs. And I understand, just like all the other OM&A in the plan, the maintenance costs here are simply being escalated by the custom revenue OM&A factor; is that correct?

L. YEUNG: Correct.

L. GLUCK: Thank you. And above Table A it describes that the maintenance expenses in Table A are intrinsically linked to the capitalized software, and given the proposed move to additional cloud computing and the related subscription costs associated with that, would you expect that you would actually need unescalating non-capitalized maintenance budget related to the traditional software assets?

L. YEUNG: So, in Table A the first line is to show the capitalized software in that particular year. But then the software will still be in use in the following years. So we do believe that the non-capitalized maintenance should maintain.

L. GLUCK: Even as you are moving towards more cloud, and I recognize that these are just capital expenses in the year, but, you know, you are moving away from assets that you obviously purchased in the prior period. For example, from 2021 to 2025 you have capitalized software, software property depreciates over around five years, and you are moving toward cloud computing. So your response is that you would continue to need all of this unescalating, non-capitalized maintenance budget?

L. YEUNG: I am going to pass it to my colleague, Andrew Willis.

A. WILLIS: Sorry, Mr. Gluck, could you just repeat the question?

L. GLUCK: Sure. My question, at a high level, I will start there, is: Given the move to cloud computing which is quite obvious from Table B, a doubling of subscription costs associated with cloud; do you expect that you would still need the same level of non-capitalized maintenance that you described as intrinsically linked to the sort of traditional software assets that you were using in the prior period?

A. WILLIS: When we look at -- when we look at our, for example, our IT systems, we have, as you say, cloud solutions and we have on-premise systems, and the maintenance you are seeing in that line is tied to the on-premise systems. And we expect as we eliminate on-premise and move to cloud some of those costs will go down. That being said, we are seeing elevated renewal costs on annual maintenance even for some of our on-premise stuff today, which is offsetting some of those gains. And there is also, I would say -- you know, there is only so many projects we can do, so I would see that happening, but slowly over time.

L. GLUCK: So in terms of that timeframe, you are expecting during this upcoming term, the next five years, '26 to 2030, that, you know, we should expect to see both rising cloud computing costs and rising traditional IT costs?

A. WILLIS: Yes. We are going to see that in the short-term.

L. GLUCK: Okay, thank you.

Can we go to 4 -- it's CCC 36, attachment A, please. So we discussed the EAM project briefly in the context of forecasting in-service additional timing, and I think you explained to me that the purpose of the project is to allow for more accurate asset condition assessment, the optimization of lifecycle management, and improving financial forecasting; is that a fair summary of the goal of the EAM project?

A. WILLIS: Yes, I think that's accurate.

L. GLUCK: And can you confirm for me that the current asset management plan and the overall distribution system plan that underpin the proposals in the current application are based on Hydro Ottawa's legacy processes and applications?

A. WILLIS: Yes, they are.

L. GLUCK: Thank you. And if we can go to page 13 of this attachment, please. I think it's a little bit below this. Yeah, it's in this table, thank you. And using the underground assets as an example, just to confirm that I am understanding the table correctly, the business process column describes how Hydro Ottawa currently completes various tasks; is that what that column is showing?

A. WILLIS: Yeah, I think these are kind of key business process areas that was looked at when this assessment was performed. My knowledge of this is limited, so if there is any deep discussion on this, it was really more of a panel 1 question. But I can try my best to help you out.

L. GLUCK: In terms of -- maybe you can help me out with this part of it, but in terms of the pain points, my understanding from reading the report that the consultant put together, it's -- the pain points came directly from the people who do those processes through interviews; is that a correct understanding?

A. WILLIS: Yeah, we had a number of interviews performed where they looked at our -- the asset management landscape and all the technology and processes in place, and this report is reflecting on the outcome of those discussions.

L. GLUCK: Okay, thank you. I will leave it there.

If we can go to Exhibit 4, tab 1, Schedule 2, page 25, please. And I am hoping that you would be willing to undertake to provide an updated version of this table that includes actual 2024, which I understand is now available.

D. COBAN: I think this would have been a question for panel 1, Mr. Gluck. SO unless the panel can speak to it here, I propose we take it under advisement.

L. GLUCK: Fine.

J. NOWICKI: Sorry, is that an undertaking, Ms. Coban?

D. COBAN: Yes, to consider if we can provide the 2024 actuals in the same format as we see here in Table 9.

J. NOWICKI: Okay. So that will be JT2.26.

UNDERTAKING JT2.26: Consider providing 2024 actuals in same format as seen in Table 9

L. YEUNG: Sorry, just a second. I thought there was an IR response, but if you can give me one second I can find it out. This is the underground locate 2024 information; am I correct?

L. GLUCK: I am looking for the actuals, and sort of at this level of detail, yeah.

L. YEUNG: Right. May I point you to Staff 138, Table B, please. Would that answer your question?

L. GLUCK: Yes, if 2024 was updated here, then, yes, that answers my question, thank you.

L. YEUNG: You're welcome.

L. GLUCK: And my last set of questions are related to a discussion that you had with Ms. Scott regarding the calculation of 2026 overtime. And if we could go to 4 CCC 52, part (e), please. And Ms. Scott did discuss this with you, but I still don't think I understand. And in this response you describe the overtime as budgeted on recent trends excluding outlier years, and when you say recent trends, are you referring to a period of time? Is it -- can we use the evidence that's available on the record to date to see, to test how you calculated and how you forecasted 2026 overtime by removing certain years or otherwise? Or would we be unable to replicate what you've -- how you've calculated 2026 overtime?

L. YEUNG: So if we look at -- actually, if we can bring up the Excel attachment CCC 52A, please. So 2024 is a good representation of a normal year. Unlike 2022, the weather events, and also 2023, the weather events and the strike, 2024 is relatively normal. And here in this file 2024 is actual that hopefully that will provide a good comparison to our 2025 and 2026 budget.

L. GLUCK: If I were to -- I mean, I just did it very quickly, but if I just summed up 2024, it's a $4 million overtime budget, and you're requesting 4.75 million? Is that what I should take from it? You sort of started from 2024 and then moved from there? Or is it the whole historical period or anything like that?

L. YEUNG: Sorry, if you can give me one second. So you are looking for total overtime in each category; am I correct?

L. GLUCK: I was -- originally, I was trying to understand how you calculated in 2026 overtime budget.

L. YEUNG: Okay, sorry, just one second. That's -- I am just trying to sum it up. Okay. So your question is how do we calculate that in 2026 budget; am I correct?

L. GLUCK: Yes.

L. YEUNG: So it is based on the historical trend. We go to business units, each business unit, and different jobs, and we look at that. We also considered that the wages increase each year, we look at the trend. We remove any major events that we know we don't forecast that to happen again, like the labour strike and the major events. This is how we budget for that.

L. GLUCK: Okay. Thank you. Can we go to 4-STAFF-165 part (c), please? And this is my last question.

And in this response, the question is about overtime as well. And there is a footnote here that discusses that at the time of the strike, some managers were also eligible for overtime. And the way I read that is that those managers are no longer eligible for overtime in the forecast period? Is that what I should take that from the footnote?

D. BURNETT VACHON: That's correct.

L. GLUCK: The policy changed?

D. BURNETT VACHON: Yes.

L. GLUCK: Okay. Thank you, very much, those are my questions.

J. NOWICKI: Thank you, Mr. Gluck. Up next we have Energy Probe, Mr. Ladanyi. We have you down for 15 minutes; there is about 12 minutes left for today. If you want to get started on your questions and then anything additional, we can take up on Day 3.

You are on mute, Mr. Ladanyi.

EXAMINATION BY T. LADANYI

T. LADANYI: Yes, I was mute.

Good afternoon, panel. My name is Tom Ladanyi, I am consultant representing Energy Probe and CCMBC, Coalition of Concerned Manufacturers and Businesses of Canada, and my questions are on behalf of Energy Probe only.

On Monday, I asked panel 1 several questions that I was advised to ask of panel 2. And please turn to interrogatory response 4-EP-5. Can I have that on the screen? Very good, thank you.

And there, I asked that:

“Please confirm that customers that own DERs…”

…in question (c), by the way. I said:

“Please confirm that customers that own DERs impose higher costs on Hydro Ottawa than customers that do not own DERs.”

And you actually confirmed that. And if you can look at the response to (d), part (d), which is here, you confirmed that. And then you talked about what are these costs, and you list them. And I am not going to go into that.

But what I would like to ask you is that I asked that panel – actually, can I ask you what is the estimate of these costs for the test year, as in dollars? Because these are only words.

So essentially in part (d), you talked about customers who export into the grid, and that is what I want to concentrate on, not for all DER customers, because I know you have a much wider range of DERs.

T. FREEMAN: Yes, Mr. Ladanyi, thank you for the question. And sorry to bounce you again, but this question should actually be put to panel 3.

T. LADANYI: Panel 3, all right. Okay.

And now can we turn to the letter by the Hydro Ottawa sent to Mr. Murray on July 4, 2025, and it's in the record of proceeding. And you see the letter. Very good, thank you.

And in the letter, and I won't read you the whole letter, it says that:

“Early 2025, Hydro Ottawa paused its ADMS program (including SCADA upgrades) and completed a comprehensive review. The review was vital for Hydro Ottawa to navigate the ongoing energy transitions, address dynamic changes within the energy sector and optimize operational capabilities.”

And I assume that when you did this comprehensive review, you presented something to the senior management; it wasn't all verbal. Could you please file that review? It will probably need an undertaking.

A. COLLIER: This, the ADMS project, is a panel 1 discussion.

T. LADANYI: Sure, and I know that very well. But I am asking for an undertaking. So undertakings can be taken by any panel.

A. COLLIER: But we would have to see if panel 1 can provide that. Thank you.

T. LADANYI: So just a minute. EDMS is general plant, and this panel deals with general plant, doesn't it?

D. COBAN: No. We advised Mr. Ladanyi in the September 8 letter that if you had questions related to certain grid modernization investments, those were directed in panel 1. And in fact I think you had an exchange with the witness on panel 1 regarding EDMS.

T. LADANYI: Yes, I certainly did, yes. And I thought I could ask this panel some more about it, because general - they are essentially general plant investments. And I am not asking you to tell me all about EDMS. I am just asking you for this comprehensive review report, which must exist.

Is it confidential? You can say it's confidential.

D. COBAN: I just think these questions would have been better directed for the witness who was equipped to speak --

T. LADANYI: I apologize.

D. COBAN: Yeah. So we can take it under advisement and consider your request and get back to you with an answer.

A. COLLIER: Just for clarity, this is not a general plant investment.

T. LADANYI: Oh, okay, so what kind of plant is this?

A. COLLIER: Systems service.

T. LADANYI: A systems service plant. Okay. But EDMS is IT, isn't it?

A. COLLIER: It's IT, yes.

T. LADANYI: In fact, it's mainly IT. Most of the costs are IT, aren't they?

A. COLLIER: I am going to ask Mr. Willis to speak to that, but...

A. WILLIS: Yeah. This is actually our operational technology, which is under IT. So that's the distinction.

T. LADANYI: Fine, can I have an undertaking number for this, please.

J. NOWICKI: Sure, that's JT2.27.

UNDERTAKING JT2.27: OEB to consider filing the comprehensive review completed in early 2025 referred to in the July 4, 2025 letter to OEB Registrar Murray

T. LADANYI: Yes. And the actual wording of the undertaking is to file the comprehensive review completed in early 2025 referred to in the July 4, 2025, letter to Mr. Murray; it should be straightforward.

D. COBAN: Just to clarify, Mr. Ladanyi, the undertaking is to consider your request to file that and to advise you accordingly.

T. LADANYI: Yeah, of course. You can say that you don't have it, that you have lost it, that it's been shredded, that it's secret, whatever you like. I would still want an undertaking; I want an answer from you, that's all.

So I understand the OEB is developing a province-wide capacity information map in response to a directive from the minister of energy, and all distributors are participating. So therefore Hydro Ottawa must be participating.

And I would like to know, what are the O&M costs of this capacity information map?

D. COBAN: I am also confused by this, because I think you had this exact exchange yesterday with panel 1.

T. LADANYI: I didn't get an answer; that is why I am asking this panel. That is how it works, isn't it?

D. COBAN: No, it doesn't work that way. I think the reason panel 1 didn't give you an answer is - you know, I don't want to misrepresent their testimony, but if we were to go back to the transcript, you had an exchange back and forth. So we could point you to the transcript where you can find more information.

I am just struggling with your request; it just seems like you are taking another kick at the can.

T. LADANYI: No, I am not. I am asking something that is within the scope of this particular panel which deals with general plant and operation, maintenance and administration costs. And apparently I was told on Monday that, you know, this panel didn't know what it was. So, I mean, somebody must know at Hydro Ottawa what it is.

Or is this like you are not keeping track of this cost at all?

D. COBAN: Let's mark your undertaking and see what we can provide you, incremental to what panel 1 provided, if there is anything beyond that.

T. LADANYI: Yeah, let's. Can I have an undertaking number for that one, too, please?

J. NOWICKI: Yes. That will be JT2.28.

UNDERTAKING JT2.28: Provide O&M cost of Hydro Ottawa’s capacity information map

T. LADANYI: Thank you. Now I understand also that Hydro Ottawa will be putting in place a distribution system operator, DSO. And what are the operation, maintenance and administration costs of the DSO office, or whatever it will be, I don't know, it's going to be operations room, or there will be somebody working in there?

A. COLLIER: Again, Mr. Ladanyi, there's no one on this panel that can speak to that.

T. LADANYI: Okay. So, there is -- so should I be putting it to panel 3?

A. COLLIER: I think it was probably panel 1.

T. LADANYI: I put it to panel 1, they didn't know, so I mean this is quite amazing. So, again, so it's another item where you are spending money on, but you are not keeping track of it, fascinating.

D. COBAN: Mr. Ladanyi, I just want to remind you that we are in a technical conference here, we are looking to clarify, this isn't cross-examination. So I do believe you had this exchange with panel 1.

T. LADANYI: I did, I am just surprised, these are straightforward, easy questions and I am hoping I would be getting straight, easy answers. You say, well, we don't know what it is, we are estimating it, you know, something like that seems reasonable. But to say that you should have asked panel 1, and maybe panel 3, and maybe panel 15, it just -- this is a technical conference, it's a simple question.

D. COBAN: Yes, and I believe you had an exchange with Ms. Heuff on this item, I don't want to represent her testimony, but I would refer you back to the transcript.

T. LADANYI: Fascinating. Okay. Let's go on to 4-EP-4. And 4-EP-4, I asked how and why is electrification driving up OM&A costs and you responded by directing me to pages 9 and 10, Exhibit 4, Tab 1, Schedule 1, you can turn up that if you like. And so, OEB Staff asked you earlier today about -- and asked this question of panel 1 and was referred to panel 2, so very similar question. So we are now in panel 2. So, if this is, and I am assuming that you can answer that, so how much is electrification increasing OM&A from 2025 to 2026? So it's increasing from one year to the next; can I have a dollar amount for that, please?

D. COBAN: Again, I think you -- I am struggling with your questions, Mr. Ladanyi, because I think you put this question, again, to panel 1 and the answer was that we didn't look at it in that way, if I recall correctly. So I am not sure that this panel can help you with the maintenance programs that are listed here, as you know those were mapped to panel 1 in terms of the distribution system operations witnesses there.

T. LADANYI: And this is, this panel is operation and maintenance panel?

D. COBAN: No, as we noted in our letter of September 8th, maintenance programs were mapped to panel 1.

T. LADANYI: Oh, so this is just operations but not maintenance; is that right?

D. COBAN: Operations and maintenance were panel 1. I just point you back to that September 8th letter.

T. LADANYI: Actually I am very surprised by all this, but anyway let's continue. So, in discussion with OEB Staff earlier today you referred to ODERA and can you please turn to 2-STAFF-69. Now, the name ODERA stands for Ottawa Distributed Energy Resource Accelerator, so that is, it has the words DER in it. So I assume that some of the costs, in fact maybe most of the costs of ODERA are actually due to DERs; are they not?

D. COBAN: Again, if we were listening to the exchange earlier today with panel 1, there was -- the ODERA witness was speaking to the initiatives, so, again, this was an item mapped for panel 1.

T. LADANYI: And you actually don't know why ODERA is needed at all?

D. COBAN: No, what we are saying, Mr. Ladanyi, is that your questions with respect to ODERA should have been directed to panel 1. There was a notable exchange this morning regarding the ODERA project between OEB Staff and panel 1.

T. LADANYI: Because when I asked panel 1 about capital costs that are being caused by DERs, no one on panel 1 mentioned ODERA, and then there is this very large project, many, many pages, that came up and they never seemed to link it. Did they not think it -- so I don't know what they were thinking of, but I thought I could ask you at least a bit about ODERA and its linkages to DER. So you are saying you don't know anything about ODERA?

D. COBAN: No, the witnesses who are subject matter experts on ODERA were on panel 1.

T. LADANYI: So the $5.1 million, do you know anything about that amount; or nothing about that for ODERA?

D. COBAN: Mr. Ladanyi, I feel like we are going in circles here. There is nobody on this panel who can deal with the ODERA project. If you have a specific question, we can do our best to assist you by way of an undertaking.

T. LADANYI: Let's go like this: Is ODERA a general plant project? It appears to be all software, or mainly software; is it a general plant or not a general plant project?

A. COLLIER: It is not a general plant program.

T. LADANYI: Okay. It's not one of those. So I cannot ask you what are the actual capital expenditures for ODERA in 2026?

A. COLLIER: Yeah, we will repeat, Ms. Coban, we don't have the expertise on this panel regarding ODERA.

T. LADANYI: But you could take an undertaking; couldn't you? That's at least allowed. Are you refusing to even take an undertaking?

A. COLLIER: I will let Ms. Coban speak to that.

D. COBAN: We can take an undertaking, Mr. Ladanyi, if your question is specific such that it can be answered in an undertaking.

T. LADANYI: Yes. What are the general plant capital expenditures for ODERA in 2026?

D. COBAN: Okay, we will take that by undertaking.

T. LADANYI: And what are the OM&A -- just a second, I can also -- would like to include, as well, what are the OM&A expenditures on ODERA in 2026?

D. COBAN: Can we mark this down?

J. NOWICKI: Yeah, so that will be JT2.29.

UNDERTAKING JT2.29: Provide the general plant expenditures and OM&A expenditures on ODERA in 2026

J. NOWICKI: And, Mr. Ladanyi, I note we are a little bit past 5:00 now. So perhaps if you could provide an update on the time that you need to get through the remaining, remainder of your questions, or whether you would like to continue on in day 3?

T. LADANYI: No, I don't want to continue on. I think I am not getting anywhere with this panel, so maybe I will use my time on the next panel, maybe I will have more luck there. Thank you. Thank you, Panel. Those are all my questions.

J. NOWICKI: Thank you, Mr. Ladanyi. That concludes Day 2 of the technical conference. Thank you to our panelists and our participants. We will be continuing the technical conference tomorrow morning and with CAFES.

Thank you.

--- Whereupon the proceeding adjourned at 5:05 p.m.