ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**

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DATE: **March 5, 2018**

EB-2017-0049

THE ONTARIO ENERGY BOARD

Hydro One Networks Inc.

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

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, March 5, 2018,
commencing at 9:06 a.m.

TECHNICAL CONFERENCE

A P P E A R A N C E S

JAMES SIDLOFSKY	Board Counsel
HAROLD THIESSEN KEITH RITCHIE CHRISTOPHER OAKLEY	Board Staff
GORDON NETTLETON S. LISA LEE	Hydro One Networks Inc. (HONI)
MARK LOWRY* DAVID HOVDE*	Pacific Economics Group (PEG)
LISA (ELISABETH) DeMARCO CARY FERGUSON	Anwaatin Inc. and Energy Storage Canada (ESC)
SHELLEY GRICE	Association of Major Power Consumers of Ontario (AMPCO)
MICHAEL BUONAGURO NICHOLAS COPES*	Balsam Lake Coalition (BLC) and Arbourbrook Estates
TOM BRETT	Building Owners and Managers Association, Toronto (BOMA)
RANDY AIKEN*	Canadian Manufacturers & Exporters (CME)
JULIE GIRVAN	Consumers' Council of Canada (CCC)
TOM LADANYI BRADY YAUCH	Energy Probe Research Foundation
MARION FRASER*	Ontario Sustainable Energy Association (OSEA)
RICHARD STEPHENSON* BAYU KIDANE	Power Workers' Union (PWU)

*appearing by teleconference

A P P E A R A N C E S

MICHAEL McLEOD*	Quinte Manufacturers Association
JAY SHEPHERD MARK RUBENSTEIN	School Energy Coalition (SEC)
VICKI POWER BOHDAN DUMKA	Society of Energy Professionals (SEP)
MARK GARNER BILL HARPER	Vulnerable Energy Consumers' Coalition (VECC)

ALSO PRESENT:

ERIN McKINNON JODY McEACHRAN	Hydro One Networks Inc.

*appearing by teleconference

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

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

E X H I B I T S

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

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

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

Monday, March 5, 2018

--- On commencing at 9:06 a.m.

MR. SIDLOFSKY: Good morning. We are back for day three of the technical conference on Hydro One's 2018-2022 distribution rate application.

PRELIMINARY MATTERS:

Just as a preliminary matter, Harold Thiessen on Friday afternoon had sent out a message to parties asking for updated time estimates. We have gotten a fairly small response to that. I am just wondering if I can canvass people in the room, intervenor representatives, on how long they think they may be. Let's start with panel 2.

MR. HARPER: I think we are probably about 15 minutes for this panel for VECC.

MR. SIDLOFSKY: 15 minutes? Okay. And Mr. Rubenstein.

MR. RUBENSTEIN: I had 75 minutes down. I also have some of Ms. Grice's questions, so...

MR. SIDLOFSKY: Okay. And we will deal with Ms. Grice's written questions in a minute.

MR. YAUCH: We have about five to ten minutes for this panel.

MR. SIDLOFSKY: Okay. Mr. Ferguson.

MR. FERGUSON: Anwaatin has about 20 to 30 minutes left for this panel.

MR. SIDLOFSKY: Okay. And Mr. Buonaguro, are you back there this morning? You are.

MR. BUONAGURO: Hi, yeah, all my stuff got pushed over to panel 3 after --

MR. SIDLOFSKY: Okay.

MR. BUONAGURO: The little I had for panel 2 I already did.

MR. SIDLOFSKY: Okay, and Mr. Brett?

MR. BRETT: Yeah, I have about 30 minutes.

MR. SIDLOFSKY: 30 minutes? Okay. And for panel 3, VECC?

MR. HARPER: I think the original time estimates we gave are still valid.

MR. SIDLOFSKY: And that's -- I have got 135 minutes for VECC.

MR. HARPER: Yes, that sounds about right.

MR. SIDLOFSKY: Okay.

MR. RUBENSTEIN: Our original time estimates hold.

MR. SIDLOFSKY: So that would be 50 minutes for Schools. Mr. Brett, for BOMA you had ten minutes on panel 3.

MR. BRETT: Yes, that's probably about right.

MR. SIDLOFSKY: Okay. Mr. Aiken, CME.

MR. AIKEN: Five.

MR. SIDLOFSKY: Five minutes for panel 2, 15 for panel 3?

MR. AIKEN: No, panel 3 I am down to five.

MR. SIDLOFSKY: Okay. Great, thank you. Arbourbrook, so Mr. Buonaguro.

MR. BUONAGURO: I will be like five minutes.

MR. SIDLOFSKY: Okay.

MR. BUONAGURO: So just a few questions.

MR. SIDLOFSKY: And so five minutes, and you are thinking 60 minutes for Balsam Lake then?

MR. BUONAGURO: Yeah, no, that's the high end. I can be pretty fast if I have to be, but --

MR. SIDLOFSKY: Okay. Mr. Ferguson?

MR. FERGUSON: About 20 minutes for each of Anwaatin and Energy Storage Canada.

MR. SIDLOFSKY: Okay. Ms. Fraser. OSEA had indicated 20 minutes for panel 2, ten minutes for panel 3. We will check with Ms. Fraser when she comes in.

And I think that's it for time estimates. Staff?

MR. YAUCH: We had 15 minutes for panel 3 -- sorry, Energy Probe.

MR. SIDLOFSKY: Oh, sorry, Energy Probe. Thank you. Sorry, Mr. Yauch --

MR. YAUCH: 15 minutes. We didn't change.

MR. SIDLOFSKY: Thank you. And Staff will have just a few questions, maybe five minutes to follow up with on panel 2, and we are still down for 35 minutes on panel 3. We will work those times out at the break and come up with some totals after that.

Finally, as a preliminary matter, AMPCO and Ms. Grice, she had indicated on Friday that she wouldn't be able to attend today. I know that she has passed some questions on to Mr. Rubenstein. She has also sent in some written questions, and I'd like to enter those written questions as Exhibit KT3.1.

EXHIBIT NO. KT3.1: TECHNICAL CONFERENCE QUESTIONS OF AMPCO FOR HONI PANEL 2 FROM MS. GRICE.

MR. SIDLOFSKY: And if I could get an undertaking from Hydro One to provide responses to those questions, that would be helpful.

MS. GARZOUZI: We agree.

MR. SIDLOFSKY: Thank you.

UNDERTAKING NO. JT3.1: TO PROVIDE RESPONSES TO THE QUESTIONS FILED BY MS. GRICE AS EXHIBIT KT3.1

Finally, Ms. Girvan, your time estimates, have they changed from what you'd indicated originally, and --

MS. GIRVAN: No.

MR. SIDLOFSKY: -- that would be 25 minutes for panel 2, 15 minutes for --

MS. GIRVAN: No, sorry --

MR. SIDLOFSKY: -- panel 3?

MS. GIRVAN: Panel 2 I just have maybe 5 minutes.

MR. SIDLOFSKY: Okay. And panel 3 would still be 15?

MS. GIRVAN: Yes.

MR. SIDLOFSKY: Great.

MS. GIRVAN: Thank you.

MR. NETTLETON: Mr. Sidlofsky, just terms of direction what I have heard is really there has been no material change in the estimate for panel 3, fair?

MR. SIDLOFSKY: Very minor, from the sound of it.

MR. NETTLETON: And so the total hour count, I think, was about six hours; is that right?

MR. SIDLOFSKY: That's right.

MR. NETTLETON: So --

MR. SIDLOFSKY: We are still trying to get through this today.

MR. NETTLETON: Okay.

MR. SIDLOFSKY: So without further ado, I'd like to turn the mic over to Mr. Rubenstein.

HYDRO ONE NETWORKS INC. - PANEL 2, RESUMED

Bruno Jesus

Lyla Garzouzi

Imran Merali

QUESTIONS BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Thank you very much, panel. I want to start off with some questions that were punted to this panel from the previous panel. If I can first ask you to turn to issue 24, SEC 46.

I want to ask you about part E. In part E we had asked you about comments in the report that stated:

"AESI provided Hydro One with numerous other points of clarifications, suggestions. Hydro One stated that it appreciates AESI's points and suggestions. Hydro One provided AESI with comments on all these points. In some cases Hydro One did not heed the comments but explained the rationale and appreciated that they would be of assistance in more thoroughly preparing for interrogatories during the process."

We had asked you then to:

"Please provide a copy of all referenced AESI "comments and suggestions, as well as Hydro One's response."

And in the response to that interrogatory Hydro One references part C and then -- but also says:

"Hydro One relies on its prefiled Distribution System Plan in support of the relief sought in this application. The questions posed do not pertain to this evidence. Whether comments provided by AESI were or were not incorporated into the final version of the DSP in a matter beyond the scope of this proceeding."

I am somewhat unclear by this response, since you filed this report, it made this comments in this report, it's a report about the Distribution System plan. So I am just wondering if you can help me understand how so at least I understand why it's your view that that's not within the scope of this proceeding. Maybe I just missed it?

MR. NETTLETON: Well, we are starting in a rocky road again, Mr. Rubenstein. The answer as provided is as far as we go. Hydro One is not prepared to provide the requested level of detail of information that you have requested.

We tried to sort out in this response the nature of the comments that were provided and exchanged, and we, Hydro One, is taking a position that interactions of detailed responses and detailed questioning and the level of comments that were provided are just not material to this proceeding and on that basis were not provided.

We are not going to get any further than that today. So if we could move on to areas of questioning that provide clarifications, that would be great.

MR. RUBENSTEIN: So that's a continued refusal?

MR. NETTLETON: Yes.

MR. RUBENSTEIN: If I can ask you to turn to 43-SEC-86. This is another question that got punted to you.

And in this interrogatory, we had asked you to provide for each year between 2014 and '22 the percentage of OM&A that is undertaken by third parties and break down that amount by their activities, and the response was, well, you don't readily have that information and it would be -- provide an unreasonable effort to get that information within the time frame.

And I had asked the original panel if they could help us with sort of an order of magnitude, what are we talking about in terms of work that is undertaken in the OM&A category that is being done by third parties, and they thought you would be better at responding to this.

MS. GARZOUZI: So from a distribution perspective, most of our distribution work program is actually done in-house. It's all contracted to the Power Workers' Union. Within that contract we have provision for a seasonal workforce through the hiring hall. And once we exhaust that, we are able to bring in contractors. I would say the bulk of the distribution program is actually done in-house.

MR. RUBENSTEIN: No, I understand bulk. And I understand you don't have exact numbers. I am just trying to get sort of order of magnitude for the last category, where you can't use the hiring hall; you are moving to the contract workers. Are we talk less than a percent, one to five percent; if you can give me your best estimate here.

MS. GARZOUZI: I would say a percent or less.

MR. RUBENSTEIN: Okay. Thank you very much. If I can ask you to turn to issue 3, SEC 3. So in this interrogatory, we had asked: `

"Please provide a copy of benchmarking analysis, reports, opinions and/or assessments undertaken by Hydro One or for Hydro One since 2014, regarding any aspect that directly or indirectly relates to its distribution business that is not already in included in this application."

And the response is: "Hydro One has provided two studies as attachments to this response," and you provide two studies.

I just want to understand if it is fully responsive to the interrogatory or not.

Are those two studies the only two studies that were not already included in this application that would fall under the category of benchmarking analysis, reports, opinions and/or assessments undertaken by Hydro One or for Hydro One since 2014 regarding any aspect that directly or indirectly relates to the distribution business?

MR. NETTLETON: Well, Mr. Rubenstein, the question is beyond the scope of this application, and has been answered accordingly.

This application is not addressing the period of time from 2014 and forward; it is dealing with a period of time of 2018 to 2022.

The benchmarking studies that have been provided for the purposes of Hydro One's justification for the applied-for relief are those that are included as attachments 1 and 2 to this response.

MR. RUBENSTEIN: So, I am sorry. When you responded to this interrogatory was it purely based on time frame that you utilized? I just want to understand what's included and not included.

MS. GARZOUZI: Can I provide clarification?

So in the rate application, we filed four benchmarking studies; the Gardiner IT, the Navigant wood poles, Navigant stations, CN utilities for vegetation management. In this exhibit, we have attached two, the Willis Towers Watson and the CEA. So that's six.

There's a seventh one that's in progress right now, and we will be filing that in the transmission application. So that will be made available.

With this IR, we actually canvassed our vice presidents; we circulated this question around. And so to the best of our knowledge, this is what we have for benchmarking.

MR. RUBENSTEIN: All right, thank you. If I can ask you now to turn to -- just one second...

If I can ask you to turn to issue 3, SEC 6. This was another interrogatory that was punted to this panel, and we had asked you to provide summaries of all internal audit reports conducted since 2014 related to any aspect that directly or indirectly relates to Hydro One's distribution business, their findings, recommendations and any status of those reports undertaken.

You provided us, very helpfully, with an extensive spreadsheet, and we had asked panel 1, and I am going to ask you to provide a number of these reports in full. And those reports, just for the record, are report 2014-2019, investment planning; report 2015-05, asset deployment; report 2015-32, audit of construction project management process; report 2015-34, distribution asset management and preventative maintenance optimization; report 2016-17, asset deployment follow-up review; and report 2017-14 investment plan governance delivery follow-up report.

MR. JESUS: Yes, we are willing to -- are all those reports distribution-related?

MR. RUBENSTEIN: If they are in -- I believe so, and the response to that interrogatory asked you for the list of distribution-related ones, so...

MR. JESUS: So where they are relevant to the distribution business, we will provide those reports. And the reports that apply to mainly transmission, we will not provide them. Does that makes sense?

MR. RUBENSTEIN: That does. I would just maybe then ask -- in the question, we had asked you for ones that relate to distribution, so did you include -- my review is that they are related to distribution. Did you respond to the undertaking another way?

MR. NETTLETON: Mr. Rubenstein, I think the challenge is whether or not the witness is responsible for this interrogatory, and I am not sure that either of these two are the indicated witness.

MR. RUBENSTEIN: Okay. You told me to --

MR. JESUS: I don't believe that they are all related to distribution. That's the issue, Mr. Rubenstein. But if they are, we will gladly provide the reports.

MR. RUBENSTEIN: All right. Well, I guess we will see what comes out. Thank you very much.

MR. SIDLOFSKY: We will give that an undertaking number, JT3.2. I am just -- I am not quite sure about the phrasing of that undertaking.

MR. NETTLETON: Mr. Rubenstein, I believe you listed four reports; is that correct?

MR. RUBENSTEIN: Six reports.

MR. NETTLETON: Six. Maybe we could have the undertaking that Hydro One will undertake to review the six listed reports asked by School Energy Coalition, and provide the ones that relate to the Hydro One distribution business.

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

MR. RUBENSTEIN: Yes, I guess we'll see what comes from that, and then determine whether that's appropriate or not.

MR. SIDLOFSKY: Okay. So is that will be JT3.2.

UNDERTAKING NO. JT3.2: TO REVIEW THE SIX LISTED REPORTS ASKED BY SCHOOL ENERGY COALITION, AND PROVIDE THE ONES THAT RELATE TO THE HYDRO ONE DISTRIBUTION BUSINESS

MR. RUBENSTEIN: All right, down to the more enjoyable ones.

Can I ask you to turn first to issue 25, Energy Probe 37? Just give me a second here. So in this interrogatory, you were asked to provide as of 2017 how many buildings has Hydro One deemed surplus, and then what was the value of the sales of those buildings.

Are there any buildings -- so you provided a response to those and you provided the value. Are there any buildings in the test period that you are forecasting to deem surplus?

MS. GARZOUZI: I am not aware, Mr. Rubenstein.

MR. RUBENSTEIN: As in you are not aware -- sorry, I mean --

MS. GARZOUZI: I don't know this file, so I can't comment.

MR. RUBENSTEIN: All right. Can I ask you to undertake to determine if there are -- well, I'll break it down into three steps: if there are buildings that you are forecasting to deem surplus, the value of those or forecast value; and if you have included or not included those in the application.

MS. GARZOUZI: I will undertake that.

MR. SIDLOFSKY: JT3.3.

UNDERTAKING NO. JT3.3: TO DETERMINE (A) IF THERE ARE BUILDINGS THAT YOU ARE FORECASTING TO DEEM SURPLUS; (B), THE VALUE OF THOSE OR FORECAST VALUE; (C) AND IF YOU HAVE INCLUDED OR NOT INCLUDED THOSE IN THE APPLICATION.

MR. RUBENSTEIN: Can I ask you to turn to interrogatory I33-SEC-66? In many ways, this is interrogatory follows up on a lot of the questions that Mr. Garner had asked actually, I think, of the first panel that got pushed to you, and it's with respect to how you forecast in-service additions.

As I understand it -- and I think it was very similar to what happened in the transmission, how you make a determination of moving from capital to in-service additions is for the projects you are able to determine that on a specific basis. And for programs, if I recall from the transmission application, it's essentially you are able to determine as a percentage of how much you are spending in capital expenditures in any given year would equal in-service additions in any given year. Is that the same thing for distribution?

MS. GARZOUZI: So we have projects and programs. The project is in-service upon completion of the project. For programs, if we take the wood pole replacement program as an example, it is capitalized monthly.

MR. RUBENSTEIN: And sort of we are talking about programs in a general way. What's the way that you determine when you are in-servicing based on a capital expenditure envelope how much of that would be in-service in a given year?

MS. GARZOUZI: Most high-volume component programs are capitalized monthly. So under storms, wood pole replacement, metering replacement, and so on and so forth.

MR. RUBENSTEIN: So when you say it's capitalized monthly, I'm -- the budget has a certain amount of expenditures, you plan to spend capital expenditures, you then are translating that into in-service additions. For the program components what's -- my understanding from when we had this discussion of the transmission rate case it was -- and I don't know the exact numbers -- for the programs it was 95 per cent something-odd you would know that that's the annual capital expenditure, what I would call in-service addition ratio and I am just trying to understand how this works in the distribution, if it's similar or not.

MR. NETTLETON: So Mr. Rubenstein, it may be helpful if Ms. Garzouzi could comment first on differences between the transmission planning function and the distribution planning function, and I think one of the major differences from my understanding is that the amount of capital projects in the distribution side of things is predictable, and the scope of that, and that influences the way the planning is done.

So Ms. Garzouzi, could you shed some light on that?

MS. GARZOUZI: I would say most of the distribution programs are capitalized in year. Does that help?

MR. RUBENSTEIN: Yes.

MS. GARZOUZI: Okay.

MR. RUBENSTEIN: But I want to understand what the --

MS. GARZOUZI: What the ratio --

MR. RUBENSTEIN: Is it 100 per cent? And the reason I ask just sort of -- it became an issue in the transmission case of trying to understand if the Board said, well, we want to reduce your capital expenditures by 10 per cent, you know, for a certain program, well, what does that mean for in-service additions, right? Is it a one-to-one ratio, is it less, and I am just trying to have that information out now instead of the back end.

MR. NETTLETON: And the trouble is, is that this witness doesn't have the background on the transmission case. So again it would be -- I think it would be really helpful if you explore with Ms. Garzouzi the nature of the programs, the nature of the capital budget, and how the planning of the budget is carried forward in distribution alone.

MR. RUBENSTEIN: Well, sure. So how about if I give you an example. The distribution station demand capital program -- this is SR01. And you're planning to spend about $2.3-million a year through the plan, as I read the evidence. That's as I understand on a capital expenditure basis. How many -- say we are talking about 2018, which is $2.3-million are being spent. What's the in -- how much in-service additions of that $2.3-million would be -- would be in -- how much of in-service additions would relate to those $2.3-million of spending, as opposed to, say, the 2017 amounts?

MS. GARZOUZI: I would need to take you program by program, and every program would have its own ratio. I would say the bulk of the distribution work would be in-serviced in year, and that ratio of the in-service to the capex would be 90 per cent plus.

MR. RUBENSTEIN: So is it possible if I could ask you by way of undertaking to do that with the programs? I know you are saying 90 plus, but a number needs to come out of that so if later on in the proceeding we can understand what the actual, if a reduction -- if the Board orders a reduction what that means, so I was wondering if you could do it by undertaking, go through the programs, provide the ratio.

MR. NETTLETON: Sorry, Mr. Rubenstein, you are asking for a ratio of expected in-service additions from each of the forecast capital projects and programs forming the budget?

MR. RUBENSTEIN: Well, so I understand -- I am talking about programs only, because my understanding, projects you know. You can -- they are big enough you know what year you are doing, when --

MR. NETTLETON: So it's just -- okay. So it's just on the program side?

MR. RUBENSTEIN: Yes.

MR. NETTLETON: Just the amount of the in-service additions that you are expecting in 2018. We will take one year?

MR. RUBENSTEIN: Well, I assume it's on a --

MS. GARZOUZI: You are asking for the ratio, I believe.

MR. RUBENSTEIN: The ratio.

MS. GARZOUZI: Is that what you're asking for? We can provide that. Just to reiterate, on the distribution system, the bulk of the spend is going to be in-year, and like storms, for example, will be in-serviced entirely in year, poles and so on and so forth, but we can provide it for the programs.

MR. NETTLETON: Ms. Garzouzi, just the term of art that's being used is in-year. Can you just elaborate on what you mean by "in-year"?

MS. GARZOUZI: Yes, I mean that when it's spent it's going to be capitalized, and that capitalization will occur in the same calendar year, usually month over month.

MR. RUBENSTEIN: Thank you. Can we get an undertaking for that?

MR. SIDLOFSKY: JT3.4.

UNDERTAKING NO. JT3.4: TO PROVIDE THE AMOUNT OF THE IN-SERVICE ADDITIONS THAT YOU ARE EXPECTING IN 2018.

MR. RUBENSTEIN: Can I ask you -- there's a number of interrogatories, and they are not actually specific to you, but what I am asking is -- so there's -- an example would be interrogatory issue 10, Staff 58, and there's another one, Staff 27, and they had -- it's revolving (sic) the Navigant substation refurbishment benchmarking report. And we can pull one up, but if we flip to the second page. In a number of -- both these interrogatories you are asked what's the definition for -- what's Navigant's definition for these various projects that it benchmarks. And I couldn't find anywhere in the evidence -- and maybe it wasn't asked or you didn't provide it, how many full station rebuilds and substation-centric projects, meaning this definition, are you planning to do in the test period and what the cost of those are. Can you either point me to somewhere else, or are you able to provide that information?

MR. NETTLETON: Mr. Rubenstein, is the underlying question that you have whether Hydro One uses these definitions, which are from the benchmarking study --

MR. RUBENSTEIN: No --

MR. NETTLETON: -- from Navigant as part of its investment planning process?

MR. RUBENSTEIN: Well, it's a little different. You provided information that met these for the purpose of that benchmarking, and I am just trying to understand, so we have a benchmark of those costs, and I am just trying to understand, well, how are we, on a going-forward basis, are we meeting that benchmark cost? Where are we? We know in the past because it used historical data to get to this point. Now for the test period are there projects that meet these categories and would the unit costs of those be similar?

MR. NETTLETON: But the benchmarking studies are not forward-looking.

MR. RUBENSTEIN: Well, no, I understand that, but I -- well, I am trying to look at them in a forward-looking way.

MR. NETTLETON: No, I -- but -- so the investment planning exercise is forward-looking.

MR. RUBENSTEIN: Yes.

MR. NETTLETON: But we are applying definitions from a benchmarking study that are, by design, intended for a benchmark of past results. So it's -- I am just -- it's -- it seems like we have two different concepts going on here.

MR. RUBENSTEIN: Well, I am not sure I would agree. I mean, the question is are you doing projects that would meet these -- are you doing work that meets these definitions on a going-forward basis, putting aside the utilization of that information, and do you have the costs for those --

MR. NETTLETON: These fair. I mean, I guess the question is -- for Mr. Jesus and Ms. Garzouzi is do you use these terms, these definitions, when you carry out your planning -- your investment planning exercise.

MS. GARZOUZI: If I point you to Exhibit I, AMPCO 27 it has the number of stations that are planned over the period from 2018 to 2022. I am trying to tie it back to your question, Mr. Rubenstein. That gives you the station count.

MR. RUBENSTEIN: But the Navigant report breaks stations down into full station rebuilt and substation-centric and it provides definitions of both. So assume Navigant asked you to fill out the exact same form or whatever it asked you to do when they were gathering information on an historic basis and they were saying, with respect to your plan for 2018 and 2022, do the same thing; could you do it?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: Can you undertake to do so?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: That's JT3.5.

UNDERTAKING NO. JT3.5: WITH REFERENCE TO THE NAVIGANT STUDY, TO BREAK STATIONS DOWN INTO FULL STATION REBUILT, AND SUBSTATION-CENTRIC, WITH RESPECT TO THE PLAN FOR 2018 AND 2022

MR. RUBENSTEIN: And, I mean, just to simplify it, they maybe have asked you to do many different things and breaking the components down. I am just seeking how many of those top two categories and what the cost would be to do that work.

Can I ask you to turn to issue 24, Energy Probe 34? In this interrogatory, you were asked to break down certain reliability information, and the charts go from 2012 to 2016. Are you able to provide 2017 data when available?

MR. JESUS: Yes, we are. Actually, the 2017 is already there. And if you look at interrogatory I24-SEC-37, all the information is updated up to 2017. If you continue on, it's all there. The graphics aren't there, but the tables are all there.

MR. RUBENSTEIN: But this is broken down into urban and rural.

MR. JESUS: So the urban and rural are also provided in Energy Probe I18, 019 it provides the breakdown -- sorry, Energy Probe 34 -- sorry, it provides a SAIFI/SAIDI update for URU urban, rural 1, rural 2. So Energy Probe 34, I24-Energy Probe-34.

MR. RUBENSTEIN: This is the interrogatory I have taken you to.

MR. JESUS: Keep going down. Keep going. It's all '16; is it?

MR. RUBENSTEIN: Yes. So how about you provide me with an undertaking, and if there's some interrogatory you can point me at, then that's the answer. And you could do that orally or not.

MR. JESUS: I think we provided so many of these tables. I think we should have just provided '17 and called it a day, to be honest with you, but...

MR. RUBENSTEIN: I understand.

MR. JESUS: One more second before I actually take on that undertaking, because I know we have provided that information, although I could be wrong.

One second. We will find the interrogatory or provide the update, that's fine, Mr. Rubenstein.

MR. RUBENSTEIN: Thank you very much.

MR. SIDLOFSKY: We will give that an undertaking number, JT3.6.

UNDERTAKING NO. JT3.6: TO PROVIDE THE 2017 DATA IN THE TABLE AT I24-ENERGY PROBE-34

MR. RUBENSTEIN: If I can ask you to turn to issue 24

AMPCO Number 1. In part A, you were asked to please provide the start and end date for the seven planning process stages, and then you point to 24-SEC-36. The ones I am interested in are the investment development investment optimization and investment approval and implementation, and I just cannot cross reference those three. And you can maybe point me out what exactly they -- where they are on this table, which ones you consider which category.

MR. JESUS: If you scroll down -- just stop there. So the business planning process is initiated in June of 2016. So the business planning you see there on the third row, May 27th, business planning, weightings are criteria with the CFO/CEO. And then the next line, June 2nd, 2016, the business planning process is initiated.

So that's when it starts the development of the candidate investment plans.

MR. RUBENSTEIN: I am not sure if you have the other interrogatory, at B and C of the previous one where it says investment development and there's -- well, let me take you to that one quickly.

MR. JESUS: So investment development is effectively –

MR. RUBENSTEIN: One second. Switch to the second page, where there's the table of the three -- it's these three categories I am looking for, yes.

MR. JESUS: So investment development, when the system is opened up, planners are developing their investments and that is effectively the first investment development phase that you see in that table.

MR. RUBENSTEIN: So is that on June 2016, where it says planners input candidate investment --

MR. JESUS: No, so that's the start of that. If you go back up to the top, so that will go on until the optimization takes actually takes place.

So the -- in the chronology, it will go effectively until -- if we bring it back up --

MR. RUBENSTEIN: So I have early to mid-August, it says prioritization and risk optimization of candidate investments.

MR. JESUS: No. So it would effectively go until July of 2016. So that development is going on for the period of a month effectively, and then we're -- then we are waiting for the customer engagement results which are -- the themes are being brought to us in June of 2016.

MR. NETTLETON: Can I just step in, Mr. Rubenstein, just so the record is clear?

The first category, Mr. Rubenstein, that you had was investment candidate development. And I just want to be clear, Mr. Jesus, that what you are referring to in your testimony here is that that identification process took place in June 2016. It started in June 2016 and went through to July 2016; is that --

MR. JESUS: That's correct.

MR. NETTLETON: Okay. And then the second is the optimization, and I think Mr. Rubenstein is asking about time start and ending periods for the optimization process.

MR. JESUS: So the optimization process is happening in mid August. So you see there early to mid August, prioritization and risk optimization. So up until that point, we are effectively in the investment development. So is it's going on from June until mid August. And then we optimize, and we determine the optimum plan at that point in time.

MR. RUBENSTEIN: All right. And the approval then would be, I guess --

MR. JESUS: So the approval, the final approval, is December 2nd at the board of directors meeting.

MR. RUBENSTEIN: All right, thank you very much. If we can stick -- stay to -- on AMPCO Number 1, issue 24. Actually, you know -- well, we will go back to that, I guess.

So here you provide the -- at part B and C you provide how the number of -- can investment changes and how the dollars change between years and totals change.

I was wondering if you are able to break down each of those three steps into the four spending categories. So system access, system renewal, general plant, so we understand not just what the changes were overall but in which categories.

MR. JESUS: So the changes between investment development and optimization or in optimization and approval? What are you --

MR. RUBENSTEIN: All three.

MR. JESUS: All three?

MR. RUBENSTEIN: Actually, just expanding those three tables into the different sub-categories that the board uses.

MR. JESUS: Yeah, we can do that. But if you'd be willing, at the end of the day the difference really is between updating the forecast with projects that are in execution, so there are much projects that we had to account for changes in cost, and there are IT business changes that occurred during that period of time, and those were effectively the differences that are accounted for there. But we will break it down into the four categories.

MR. SIDLOFSKY: That will be JT3.7.

UNDERTAKING NO. JT3.7: TO BREAK DOWN EACH OF THE THREE STEPS INTO THE FOUR SPENDING CATEGORIES. SO SYSTEM ACCESS, SYSTEM RENEWAL, GENERAL PLANT, SO WE UNDERSTAND NOT JUST WHAT THE CHANGES WERE OVERALL BUT IN WHICH CATEGORIES.

MR. RUBENSTEIN: Thank you very much. Can I just ask you about what you -- you used the language of "candidate investments", and I just want to understand how that differs from the language we are using in other parts of the application of programs and projects.

So I assume a project is -- a candidate investment is also a project; correct?

MR. JESUS: Yes.

MR. RUBENSTEIN: But a program is -- is a program a candidate investment?

MR. JESUS: Yes. So is it's -- the difference is between a candidate and a -- the differentiator is it's not -- it hasn't made it into the investment plan until it's actually been approved, so up until that point in time everything are candidates to be able to optimize and prioritize across those projects and programs.

MR. RUBENSTEIN: So one candidate investment would be pole replacement program.

MR. JESUS: Sure.

MR. RUBENSTEIN: Okay, thank you very much.

If we can go back to 24-SEC-36. And if we go looking down that table, in September 2016, 2017, and then September 27, 2017, you have the CFO and then the CEO, CFO review the draft investment plan. I am just trying to understand, what exactly are they reviewing? Like, what -- when we talk about an investment plan, I understand what shows up in the application as sort of the final plan. But what exactly are they reviewing?

MR. JESUS: So they are reviewing the overarching impacts of what the plan is going to be doing. Obviously from a planning point of view, we need to balance the rate impacts to our customers, because we had a customer engagement process that informs the business planning process. We are looking at the asset condition and the needs of the system, and effectively they are looking at whether or not it makes sense whether or not we are delivering on our business objectives.

MR. RUBENSTEIN: But, I mean, I mean maybe more literally, what are they physically sitting, like, what is given to them? I just -- in some sense -- like, I am trying to understand that now --

MR. JESUS: So the board materials that we presented to them are available to you in the -- in Exhibit...

MR. NETTLETON: And Mr. Rubenstein, just to be clear, the line item reference that Mr. Jesus pointed you to, it is in respect of two specific plans, plans A and B.

MR. RUBENSTEIN: Yes.

MR. NETTLETON: And so that ties back to the reference that Mr. Jesus is going to give you in terms of what materials about plans A and B were presented to the board.

MR. RUBENSTEIN: Yes.

MR. JESUS: So the board materials, the board of directors presentation materials and the materials that would have been preceding that are identified in I3-SEC-4.

MR. RUBENSTEIN: So they are reviewing the same things that ultimately would go to the board of directors, I would assume.

MR. JESUS: Ultimately. So these are recommendations that are going to the CEO and CFO with respect to the plan, and at that point in time it was only plan A and B that was being presented to them, and you have the materials that provided that recommendation.

MR. RUBENSTEIN: Thank you. If I can ask you now to turn to I, tab 3, SEC 4.

MR. JESUS: SEC?

MR. RUBENSTEIN: 4. And I am looking at attachment 2. And I am looking at -- one second. Let me just make sure I know what page I am looking at here. Sorry, I apologize. And I am looking at page 3 of that. I think you're on page 2, or -- yes. So on page 3 here you have -- under "investment plan" you have the business objectives, and you have the descriptions. And then you have the weights for those. Do I have that correct?

MR. JESUS: Yes.

MR. RUBENSTEIN: And if we go to the evidence at B1-1-1, DSP section 2.1, page 2017 -- 27. It's a similar table, but I have slightly different objectives or -- by category, and the weights are different, and I am just trying to understand what happened or what's the difference.

MR. JESUS: So the difference, all of the business prioritization criteria and the weights are identical except for the last one, the financial benefit. That's the only differentiator between the two exhibits that you showed.

And the difference there is that when we are doing the investment planning, we are looking at the investment benefit that -- from a financial point of view that that investment is going to bring. So, for example, if we are doing an IT project, what's the productivity, what are the benefits that that particular project are bringing, and that's why that's accounted for separately.

MR. RUBENSTEIN: But the weights are different, so in the first table customer is 20 points out of 100.

MR. JESUS: And customer is 20 points there as well. They are all the same.

MR. RUBENSTEIN: No.

MR. JESUS: No? Okay.

MR. RUBENSTEIN: The points are different, but here you have your total points equals 100 in the November 11th version, so the points equals weight. And then in the evidence in the DSP, the points now have increased and the weights have decreased.

MR. JESUS: Right. So the weighting the points, let's just -- rather than looking at it overall, including the financial benefit, they are all still identical. You would agree with that? That from the weighting customers 20 points, reliability is 15, there hasn't been any change from that perspective.

The only change that's occurring here is the financial benefit, where we are intentionally trying to capture the benefits that -- and the, I will say return on investment is what we are capturing in that last item. So if there's anything over and above those we want to capture it from an investment planning point of view.

MR. RUBENSTEIN: What does (sic) achieve the ROE allowed by the OEB as a benefit? Can you explain an asset where that would be a benefit?

MR. JESUS: So the example I gave you is from an -- with an IT project, if we were going to undertake an IT project we would have a rate of return, if you will, or a payback period that we would need to look at and a productivity stream associated with that particular investment. So that's how the planners are using it in terms of evaluating the various investments.

So ROE, it doesn't come into play. It's really truly all about the specific investment and the payback, and the IR rate or the benefits that that particular project are bringing.

MR. RUBENSTEIN: Can I ask you to turn to Tab 3, SEC-1 -- let me just make sure I have the right one here. Hold on one second.

So I am in -- I am just trying to recall which attachment. I think this is on page 699 of the PDF, if I have this right. Yes.

And this is with respect to the program alternative slide. And as I understand looking through a bunch of other presentations, when you are inputting into the AIP system, this is the candidate, you are selecting a various program alternatives.

I am wondering if you can help me just understand that component.

MR. JESUS: Right. So from a program point of view, a planner would identify the various levels that we need to address the asset condition and the asset needs on the system.

So from a -- it's effectively driving at the pacing of the investment. So you get from a vulnerable level, which means that we are not keeping up with the pacing, we are not keeping up with the needs of the system. An intermediate would be effectively keeping up with the needs of the system, and asset optimal would be going beyond that.

So most of the time, we are in vulnerable or the next level up from an intermediate perspective, in terms of how much risk that particular investment and that level of investment is delivering.

MR. RUBENSTEIN: So when we talk about alternatives, this is what you mean by alternatives to doing various program work? It's not do other things; it's simply a different pacing of programs, the spending in a program, or the type of work in a program?

MR. JESUS: Correct. Because, for example wood poles, you need to replace the wood poles because we have a backlog of 106,000 wood poles that need replacing and it's really about how quickly are we going to get to them.

So at the end of the day, they need to be replaced and there is no other option other than replacing those poles.

MR. RUBENSTEIN: There was a lot of discussion on Friday about 24-Staff-100, where there is the sort of baseline risk versus residual risk table.

MR. JESUS: Okay.

MR. RUBENSTEIN: We can pull it up, if you want, or you may recall that table quite well.

MR. JESUS: That's okay, I am good.

MR. RUBENSTEIN: Is the risk for the programs only on an asset optimal level, and there's also a different risk associated then if, say, you are inputting intermediate or you are inputting vulnerable?

MR. JESUS: So they would be required to input the various levels. They would be required to input the vulnerable, the asset optimal, and as appropriate beyond that. Most of the times, we don't even bother going beyond that, because we know the funding is not available.

MR. RUBENSTEIN: So for the table that you provided where it has -- so the programs are listed.

MR. JESUS: Yes.

MR. RUBENSTEIN: You only have -- you don't break it down into the various asset optimal, intermediate, vulnerable. In my understanding then, is the risk assessment that you have done or you have provided in this table only for the optimal level?

MR. JESUS: No, sir. It's based on the one that was selected. So only the programs and the various levels that were selected are shown in that table.

So many of them are actually at the vulnerable level, which means it ain't getting any, any, -- there's no -- the bottom line is we need that money to actually continue on with that program; we can't cut anymore.

MR. RUBENSTEIN: Are you able to tell us for those programs actually which --

MR. JESUS: Which level?

MR. RUBENSTEIN: -- which level you have selected?

MR. JESUS: Yes, we can.

MR. SIDLOFSKY: We will make that JT3.8.

UNDERTAKING NO. JT3.8: TO ADVISE WHICH LEVELS HAVE BEEN SELECTED FOR WHICH PROGRAMS

MR. RUBENSTEIN: Maybe we can turn to 24-Staff-100. I just have a couple of questions about the optimization process, so I can get a better understanding of it.

So 24-Staff-100, and if we can just go to the table and just -- we can use the first one as an example, SR1, distribution demand capital.

You identify three risk types for that. You see customer risk, reliability risk -- sorry, four -- safety risk and shareholder value risk; do you see that?

MR. JESUS: That's correct.

MR. RUBENSTEIN: Now, there are more than those four risk categories. Are you saying that there is -- are you excluding those risks, or are you giving it a score of zero? How do you take into account the other risks?

MR. JESUS: So where they're not shown means that they would not have been assessed in those other elements. They are not important with respect to this particular program.

MR. RUBENSTEIN: So when you are doing optimization, because you are weighting based on a number of them, are you then re-weighting and only including these four, or are you giving it a score of zero?

MR. JESUS: You are giving at it score of zero. So if these ones were only weighted on the four, they would only get the weighting associated with those risk categories and zero on the other risk categories.

MR. RUBENSTEIN: Now, you are putting all the projects and the programs into the IAP. For the projects -- sorry, for the programs, you are putting multiple program alternatives which have their own risk, and then there is an optimized -- you know, someone -- there is an output to this. What exactly is that output? Is it a ranked list that has score -- you know, composite score 100 and it goes all the way down to the lowest composite score when you take into account all the risk? What exactly is the output?

MR. JESUS: So the output -- so the output is really, it's optimizing against economic factors within the time period. So we are looking at the dollars, if you will, per unit of risk mitigated over the five-year period of time.

So at the end of the day, we are ranking all of the investments in terms of the risk that they're mitigating and addressing for the dollars that we are spending; that's the output. And the investments that make the cut below the line, and investments above the line are the ones that are excluded.

MR. RUBENSTEIN: So we get a composite risk score --

MR. JESUS: Yes.

MR. RUBENSTEIN: -- essentially, based on the information on the risks. And then you essentially take the dollars you are spending and dividing it by that risk score?

MR. JESUS: We need to make sure that we are managing and addressing all the risks on the system, so -- not all the risks. So the ones that are, that have significant importance from, we need to address that particular risk. So we are -- there is a rank list in terms of risk points mitigated per dollar, but it's really the total risk is what we are looking to mitigate.

MR. RUBENSTEIN: Are you able to provide the output of the optimization so we can see what that looks like, what we are talking about when we say dollars per risk mitigated, what the composite scores are?

MR. JESUS: Yes, we are able to provide that.

MR. SIDLOFSKY: That will be undertaking JT3.9.

UNDERTAKING NO. JT3.9: TO PROVIDE THE OUTPUT OF AN OPTIMIZATION SHOWING DOLLARS PER RISK MITIGATED, SHOWING THE COMPOSITE SCORES

MR. RUBENSTEIN: Thank you very much, that's very helpful.

If I can ask you to turn to Staff 89, this is under issue 24. If we can turn to page 5, this is the risk table that we talked about on Friday. And I was just wondering, if we sort of go across the table to cost impact, and so you have different risks based on the cost impact.

I just want to understand what that cost impact is representing, the cost if something went wrong, the project costs, the cost that it may go over budget. What exactly is that representing, that category of risk and the calculation?

MR. JESUS: Could you blow it up a little bit more so I can see these values? Can you scroll down? Keep going.

So those are the values from a capital impact to the company. So it's the risk to the company in terms of dollars. So, for example, if you're looking, if you scroll to the left, if you will -- yes. Keep going. Keep going.

So what it's saying is that for severe category, the risk or the capital impact to the company in order for it to be a severe risk needs to be that number, the number $100 million to $300 million.

MR. RUBENSTEIN: I understand that. I am just trying to understand what does that capture. Does that capture if you don't do a project what is the alternative -- if you don't do this and then there's an outage --

MR. JESUS: That's correct.

MR. RUBENSTEIN: Those costs? Is it the cost that it may go over budget and different projects have higher or less likelihood of that happening?

MR. JESUS: No, it's the cost impact from a capital point of view to the company. In other words, what's the risk to the company.

MR. RUBENSTEIN: If we don't do it?

MR. JESUS: If you don't do it.

MR. RUBENSTEIN: Okay.

MR. JESUS: So these are referred to as the risk tolerances, and they capture those risks that are identified there.

MR. RUBENSTEIN: If I can ask you to turn to issue 24, CCC 23. And you make the comment that the next DSP is expected to be developed during 2018. So is this the DSP that would be for 2023 through 2028 or whatever the five years after that is?

MR. JESUS: I am sorry, can you repeat the question?

MR. RUBENSTEIN: If you take a look at line 26, you make the comment, the next DSP is expected to be developed during 2018. What is the -- are we talking about a DSP for 20 -- beginning in 2023, your process begins in 2018, or...

MR. JESUS: So this is an annual process that occurs every year. So we will be undertaking the next -- the next, if you will, distribution system plan starting this year, because things do not -- things don't stop. At the end of the -- we are effectively developing a new distribution plan on an annual basis. We do that cyclically.

So every year, the plans may change. And we have the planners develop the candidate investment plans, we go through that process every year, and we are starting that process now.

MR. RUBENSTEIN: So this is really just meeting your normal annual planning process --

MR. JESUS: That's correct.

MR. RUBENSTEIN: It's not the DSP that you are going to be presenting to the board --

MR. JESUS: No, no, no, sir.

MR. RUBENSTEIN: Thank you very much.

If I can ask you to turn to 29 AMPCO 31. And they ask you to provide a number of different tables. And in your response you say:

> "Hydro One does not report customer interruptions to the level of granularity required for equipment sub-component failures."

And so on. When you mean you do not report, is that the same thing as you do not track?

MR. JESUS: We don't track; that's correct. We don't track the failures at the sub-component level. We don't have that information.

MR. RUBENSTEIN: If I can ask you to turn now to Staff -- sorry, issue -- I think it's issue 29, Staff 164. And here you're asked to provide, in part B(i) -- so just as a background, much of this is referencing the SAIFI and SAIDI impact calculations that you did in the evidence, and you are asked to essentially provide in part B(i) essentially the calculations of how you came to the numbers, and you provide in part B(i), in the example calculation for the poles, how you came to the reliability impacts, and then you essentially point to -- look at the evidence for the underlying numbers of the other programs.

The problem is those must be calculated on a different basis, because you can't do the same type of calculation for the others that you have done for poles.

So maybe you can help me. I am trying to do your numbers, trying to figure out how you have come to the same conclusion, and I am unable to do so.

So I was wondering, is there an Excel spreadsheet that sits behind this that you are able to provide that does these calculations?

MR. JESUS: No, sir, we don't have an Excel spreadsheet that comes to those conclusions, no.

So effectively what we have demonstrated there is what we have done for poles in terms of the differences between plan A, B, and C, and B modified, and we did the same for the other components.

MR. RUBENSTEIN: But -- so let me walk you through one of them and you can --

MR. JESUS: Sure.

MR. RUBENSTEIN: -- and I can help you understand why I don't come to the same numbers. I can't replicate it.

So if we can go -- well, let me just walk you through what I think this is saying for what you have done for poles.

You have come to the conclusion you need to replace, and I think the evidence talks about 106 in poor condition, 106,000 in poor condition, and then you -- at the end of the planning period you -- in Plan A, B, C, Plan Modified D these are the remaining poles that will be in poor condition based on the various type of work.

And then essentially, you know, if you have 12.3 percent less poles in worse condition, the reliability should improve by roughly that.

MR. JESUS: Exactly.

MR. RUBENSTEIN: But if we go to distribution stations as an example -- and I will take you to DSP section 2.4, page 4, where you break it down.

MR. NETTLETON: Let's just take him there. Do you have an exhibit reference?

MR. RUBENSTEIN: Yeah, B-1-1-1, DSP 2.4, page 4.

And so if I am doing the same type of logic, you say at line 10:

"Hydro One operates 1,005 stations, which 70 are in poor condition."

Do you see that?

MR. JESUS: Um-hmm.

MR. RUBENSTEIN: So if I was -- and then if you go to line 19, as an example, Plan A says:

"Process replace all stations deemed to be in poor condition in 70 by the end of the planning period 2020."

If I was using the same logic as poles I'd have -- you would have solved that problem. It would be 100 percent. And yet here the SAIDI and SAIFI is forecast to improve only for 14 percent for that asset.

So I am trying to understand how you have come to your numbers.

MR. JESUS: Sure. So can I take you to I29-AMPCO-27. So the logic that we just followed for poles would be applied to the other components.

So if you go, scroll down, so there you can see -- in B you can see the differences in the poles being replaced in each of the years. If you scroll down again, you can see the stations that are being done, and effectively the same process would apply. So you'd look at the stations and the number of transformers that you're replacing with each one of the plans, and you determine what the reliability impact of that would be. Similarly for right-of-way.

So that was the process. The spreadsheets are there.

The math would work effectively the same as what we were looking at.

MR. RUBENSTEIN: So then why would -- based on what I was taken in the DSP -- and maybe I'm -- you're understanding this and I am not. That's probably what's happening here -- if you are doing all the poles in poor condition --

MR. JESUS: No, we are not, we are not. I mean, that calculation, that original -- the interrogatory that you had brought up, we are only doing 9,000 -- is it 9,000, Lyla, of the 12 -- of the 106,000 poles in each of the --

MR. RUBENSTEIN: No, for stations.

MR. JESUS: Oh, sorry. Okay. Sorry.

MR. RUBENSTEIN: So stations, you say 70 are in poor condition.

MR. JESUS: Yes.

MR. RUBENSTEIN: And in Plan A the proposal is to replace 70, so one would assume then you would have -- using the same logic, you would solve your problem of stations, except you don't get 100 percent improvement, you get a 14 percent improvement.

MR. JESUS: Yeah, and the rationale is that we would still have stations that fail that are not in poor condition. There would be some events that would need to take place. But at the end of the day, we would effectively in plan A address most of the poor condition stations.

But there would still be some failures, as we have demonstrated in the exhibit where we show the number of failures occurring each year.

MR. RUBENSTEIN: Sure, but we are not talking about -- there's a difference between 14 percent, which is -- I am not saying it's small for the overall thing. But if you are replacing all of them in poor, one would assume you'd have -- using the same logic as the poles, you would have a much bigger impact.

I am just unclear because you didn't make the same assessment in the poles to say others will fail, too, we just don't -- that are not in the poles, which I understand will occur. So maybe, by way of undertaking, you can break down the other categories and the same calculations and you can -- it clearly does not -- the same logic that you provided in A does not work for the others, and I am trying to understand how I could -- you have made a -- you have made a simplistic model. But the idea is to try to show when we do things, there are reliability benefits.

I am trying to essentially do the exact same calculations and make my own model that does the same thing. It works fine with poles based on it, it doesn't -- you don't have something behind it. I am wondering if you can just provide the same calculation that you did with the poles in the Staff interrogatory as you did with the other three categories, and reference where in the evidence you are getting the numbers or how you are deriving the changes.

MR. NETTLETON: Mark, it would be helpful -- can we just go to the DSP which shows the four categories, just so we are all clear for the record what you are asking for.

MR. RUBENSTEIN: Sure. And this is at B 1-1-1, DSP 2.4, page 6 and 7.

MR. NETTLETON: Just let us call that up.

MR. JESUS: So now that you are bringing this up, it's actually -- I am recollecting how we actually did this.

And similar, following the same logic that we did with poles where you are looking at the difference in poles between the various plans, we did the same thing with stations.

So the fact that we are replacing 70 stations out of a fleet of 1005, the reliability impact from stations is only going to be impacted by those 70 stations that we are talking about. You still have close to 1,000 stations that you are not addressing, where the reliability impact is not going to go to zero, if that's your question, if that's what you are looking for.

So the reliability impact associated with station failures will still be there, and it will be dominated by the remaining thousand stations, if you will.

MR. RUBENSTEIN: Why then for poles the logic is that you are not using the universe of poles, you are only using the universe of poor poles?

MR. NETTLETON: Because the universe is exceeding every -- they are not even getting to all of the poles of the universe of really bad poles.

MR. RUBENSTEIN: Yes, but we're trying to have apples-to-apples comparison in the different categories, right?

MR. JESUS: Mr. Rubenstein, I believe we are still considering the contribution associated with poles to the reliability. So the contribution is identified in the plan A, B, C. So you are taking effectively the universe into account, and all you are doing is tell me -- show me the difference between the poles you are addressing in plan A versus the poles you are addressing in plan B and what's the difference.

MR. RUBENSTEIN: But you created a composite at the bottom, so you are not looking at them simply on -- if you were saying look at only these individuals. Because you create a composite --

MR. JESUS: Yes.

MR. RUBENSTEIN: -- those have to be an apples-to-apples comparison to create a composite.

MR. JESUS: Correct, and the apple we are using is the SAIDI, right? And the SAIDI is being measured -- the contribution is not being measured by 9,000 poles. The SAIDI that we're measuring is the SAIDI contribution associated with 1.6 million poles. For stations, it would be the 10,005 stations.

So the station component is taking the entire universe into account, which is why we are able to normalize it.

MR. RUBENSTEIN: Can I ask you to provide the same table you provided for Staff and to -- I want everyone to be clear because this is maybe important later and I don't want to end up being nitpicking on numbers and waste a lot of hearing time.

If you are able to provide the same response as Staff essentially for each of those categories to show the calculations and how you are deriving those numbers, that would be very helpful.

MR. JESUS: Sure.

MR. SIDLOFSKY: Undertaking JT3.10.

UNDERTAKING NO. JT3.10: TO PROVIDE THE SAME TABLE AS PROVIDED FOR STAFF AND FOR EACH CATEGORY SHOW THE CALCULATIONS.

MR. RUBENSTEIN: Can I ask you now to go back to AMPCO 36. This is -- sorry, 2.4, AMPCO 36.

So in part E, you were asked to please provide the percentage of plans that were optimizable in the business cycle, and then you have the response and you provide that as part H further down on that page.

Can I confirm -- sorry, if you go further down that page. If I can confirm the application in front of this panel -- like in this application is based on the 2017 to 2022-cycle, or is it based on the 2018 to 2023-cycle?

MR. JESUS: For this application, it would be the 2017 to 2022 cycle.

MR. RUBENSTEIN: Thank you very much. Can I ask you to turn to -- well, there's a number of -- before I ask you specific things, I just want to understand the difference between three terms that are used throughout the evidence.

So we have failures, we have outages, and we have interruptions, and I am going explain to you what I think they mean, and you can tell me if I am right. So failures is something stops working.

MR. JESUS: Yes.

MR. RUBENSTEIN: And outage can be broken down into two categories -- sorry, an outage is when electricity stops flowing to some customer, and there are two types. One is momentary outage, and one is a sustained outage. And interruptions are only sustained outages? It's the interruption to outage I am not -- sometimes you used --

MR. JESUS: So for the purpose of distribution, that's correct, they are sustained interruptions.

MR. RUBENSTEIN: Okay. So if we go back to that table we were just looking at in the DSP, section 2.4 B 111, DSP section 2.4, you have for stations sixteen failures/outages per year; do you see that?

MR. JESUS: Yes.

MR. RUBENSTEIN: Just to be clear, when we are talking about stations, we are talking about transformers?

MR. JESUS: Correct.

MR. RUBENSTEIN: And for the sixteen, am I correct -- and if we go to page 2.3, page 1289, that includes two things. That includes major failure -- am I correct that that sixteen is inclusive of major failures and major failures avoided?

MR. JESUS: Major failures at stations.

MR. RUBENSTEIN: So if we go to DSP section 2.3, page 12, you have two categories of things: major failures and major failures avoided. Is the sixteen made up of these numbers?

MR. JESUS: That's correct.

MR. RUBENSTEIN: Okay, and so major failures avoided are you stopped it before it blew, essentially; correct?

MR. JESUS: That's correct. Actually, they are class 2 failures. So major failures just means we can't do anything about it. Class 2 failures is perhaps we can look at the transformer, it may be reparable. But they are still failures, they are still huge failures.

MR. RUBENSTEIN: Okay. If we can go back to the -- a minute ago, we were at pages 6 and 7 of DSP section 2.4.

So for other line components you have 2,070 outages per year on average between 2013 and 2015. Do you see that? For other line components?

MR. JESUS: Yes.

MR. RUBENSTEIN: Now, if we go to the distribution scorecard at DSP, section 1.4, page 3, the metric there is number of line equipment-caused interruptions. Is that different than other line components?

MR. JESUS: No, it would be all line-related outages or interruptions. So all components.

MR. RUBENSTEIN: So it's more than just other line components?

MR. JESUS: It would be everything else other than -- other than the poles.

MR. RUBENSTEIN: Sorry.

MR. JESUS: So on the line there's poles, and there's transformers, there's pole top transformers, there's switches, there's insulators, there's surge arresters, there's a whole slew of other components that make up the distribution lines.

So "other line components" is intended to say everything else except poles.

MR. RUBENSTEIN: Okay. So if we go to the distribution scorecard, there's a category called number of line equipment-caused interruptions.

MR. NETTLETON: Let's go to the scorecard.

MR. JESUS: Yeah.

MR. NETTLETON: If we can have the scorecard brought up.

MR. RUBENSTEIN: This is B-1-1-1, DSP section 1.4, page 3.

So there's a metric called number of line equipment-caused interruption. Is that other line equipment plus poles?

MR. JESUS: That's correct.

MR. RUBENSTEIN: So can you help me then, because on the back, if we go to that table, you're averaging from 2013 to 2015 2,070 outages per year for other line equipment and 345 outages per year for poles. But the numbers for number of line items is clearly much larger than those two numbers put together.

MR. JESUS: It's all defective equipment, including poles, all line components. So we measure based on our scorecard, based on the way we are tracking. It's defective equipment, which would include poles.

MR. RUBENSTEIN: So that -- but even if I am averaging 2,070 plus 345 per year, for both of those under this table if you look at the 2013 to 2015 for number of line equipment you are in the 7,000, 8,000.

MR. NETTLETON: So Mark, are you asking what -- how do you --

MR. RUBENSTEIN: To reconcile those numbers.

MR. NETTLETON: Yeah, what numbers give rise to these statistics shown in the scorecard? And more to the point of this application, is it for 2018, we have a forecast of 8,200 line equipment-caused interruptions and how do those reconcile to this table 53? Or 52, sorry. Is that the point?

MR. RUBENSTEIN: Yeah, what's included, what's not included between those two things, and if you want to do it by way of undertaking, that's fine.

MS. GARZOUZI: Table 52, the failure rate impact column does not include major events, force majeure, so equipment that would have failed during storms. And so it's netted out from these numbers, and that's why they are not matching up.

MR. RUBENSTEIN: So if we pulled out major events and force majeures from number of line equipment-caused interruption I'd get the same as other line equipment and poles outages per year.

MS. GARZOUZI: Yes.

MR. JESUS: Yes, I would suggest the answer to that is yes.

MS. GARZOUZI: For that period of time.

MR. JESUS: For that period of time.

MR. RUBENSTEIN: Can I ask you to undertake to confirm?

MR. JESUS: Mr. Rubenstein, can you please ask the question again, sorry?

MR. RUBENSTEIN: Well, I would like you to reconcile the following.

MR. JESUS: Yes.

MR. RUBENSTEIN: The number of line equipment-caused interruptions category and numbers in the distribution scorecard, the proposed distribution scorecard.

MR. JESUS: Yes, so can I --

MR. RUBENSTEIN: And the information included in 52 and 53 for poles and other line equipment.

MR. JESUS: Sure, can I take you to I29-AMPCO-27.

MR. RUBENSTEIN: Yes, you can.

MR. JESUS: Where we update this table based on the latest results. Did I get it... No. Sorry. That's not the right one.

MR. RUBENSTEIN: I am going to suggest we do this by undertaking, because I have another question that's going to bring in doubt what you've said, just because there is another set of categories with the numbers going the opposite direction.

MS. GARZOUZI: Okay, we will take the undertaking.

MR. SIDLOFSKY: JT3.11.

MR. RUBENSTEIN: Okay, now, if we go in that table in front of you -- this is the Table 52. For vegetation management outages you're averaging -- you say between 2013 and '15 you average 15,530 outages per year. But then when I go to the scorecard I am getting, you know, less than half of that.

And so if it include -- if this -- table 52 included removed force majeures and major storms, that clearly can't be the case for vegetation management in the scorecard.

MR. JESUS: Okay, can I take you to Energy Probe 17. I18, Energy Probe 17, which are the updated tables. Yes.

So the correct information is shown, so it appears that the original table in terms of the failure rate and impacts was out of whack, so if you look at it at these tables, Mr. Rubenstein, these are the correct information that line up to with where you are going.

MR. RUBENSTEIN: Thank you. Now I see that. Thank you very much for pointing it out. I must have missed that.

MR. NETTLETON: So I take that undertaking has been answered then?

MR. RUBENSTEIN: The last part.

MR. NETTLETON: Yes.

MR. RUBENSTEIN: Yes, although I don't think we gave it a number, so...

MR. JESUS: Sorry, what was the other undertaking that I am taking?

MR. RUBENSTEIN: This was the poles and other line equipment.

MR. JESUS: Sure. Okay.

MR. RUBENSTEIN: As I understand how you track outage information for the purposes of these reliability, something, a transformer or a pole, there's an outage, and you give it a cause code; correct?

MR. JESUS: Yes --

MR. RUBENSTEIN: So --

MR. SIDLOFSKY: Mr. Rubenstein, if I can just interrupt, does that mean you are not requiring an answer to JT3.11?

MR. NETTLETON: Correct.

MR. SIDLOFSKY: Okay. So the full undertaking was answered then.

MR. RUBENSTEIN: No. Did we give a second undertaking for the vegetation management? I don't think so.

MR. NETTLETON: The undertaking given by Ms. Garzouzi was to reconcile the numbers for the outages of the equipment found in Table 52 of the DSP and of the scorecard. It was the equipment outages. And I think what Mr. Jesus has just indicated is that that inconsistency in the numbers between the DSP evidence, table 52 of the DSP evidence has been updated by this response and equally reconciles now to the numbers that are found in the scorecard, the 8200 number found in the scorecard.

MR. RUBENSTEIN: Can you -- what was the interrogatory again?

MR. JESUS: Energy Probe I18; I18 Energy Probe 17.

FOLLOW-UP QUESTIONS BY MR. GARNER:

MR. GARNER: Sorry, it's Mark Garner. Can I jump in just because I am trying to follow it, too, as I am looking at this.

Part of the undertaking was to confirm that it had force majeure and MEDS as part of the adjustment. And the outlier was, as Mr. Rubenstein was saying, that one piece. However, I was still interested in that first part of that undertaking, which is could you confirm that the MEDS and force majeure were actually calculated in the Board scorecard, but not in the evidence.

MR. JESUS: So both exclude the force majeure and loss of supply both, as indicated there.

MR. GARNER: Both. Okay, thank you for that clarification. And while I have the mic, is there somewhere in the evidence where the terms or the definition of force majeure and MED outages is utilized, so that we understand how it's used each year in a consistent basis?

MR. JESUS: Sure, and I will direct you to -- I will direct you to the DSP evidence in section 1.4.2. So page 1.4, page 19, DSP 1.4 page 19.

If you scroll down, the definition of force majeure is there. Can you continue on? Keep going. Are we at page 19? Go up slightly up, yes. Keep going. Keep going. There, force majeure. So force majeure is defined there.

MR. GARNER: Yes.

MR. JESUS: And basically, when an event impacts more than 10 percent of customers, consistent with the OEB definition of MED, 10 percent is the definition.

MR. GARNER: Right. Sorry, Mr. Rubenstein, if I can just follow up. So the force majeure definition is not consistent applied in the sense of whether it's consistent applied in the sense of outages. So as long as -- it doesn't matter if the winds are 100 kilometres an hour or 5 kilometres an hour, if you have X outages, that creates a force majeure or an MED event. Is that the way it works?

MR. JESUS: Well, there needs to be a storm event.

MR. GARNER: Clearly, something has to happen.

MR. JESUS: There heeds no be a storm event in order the for it to be declared a force majeure event.

MR. GARNER: Clearly. But what I am trying to understand is one doesn't have to measure that by the severity of the storm. One measures that by the severity of the outcome to the equipment.

MS. GARZOUZI: Correct.

MR. JESUS: First a storm event needs to be declared at our operating centre. And then you can look at how many customers are impacted. If it's more than 10 percent, then it's declared a force majeure event.

But then a declaration needs to be intact; you need to be in a storm event.

FOLLOW-UP QUESTIONS BY MR. BRETT:

MR. BRETT: Just one clarifying question on that. Is a force majeure for you the same as a major event day?

MR. JESUS: Yes.

MR. BRETT: And if not, what is the difference?

MR. JESUS: It's the same.

MR. BRETT: All right.

MR. GARNER: And sorry again, Mr. Rubenstein. In the operating centre to call a storm event, does that have a criteria to it?

MR. JESUS: Yes, there's a criteria

MR. GARNER: Could you share that with us?

MR. JESUS: Sure. In the control room, if we have a level 1 storm means that we have more than 100 customer outages or outages out in the field, it would be declared a level 1 storm.

MR. GARNER: Again, just so I am getting this right, again it's not weather dependent. It's a reporting of the outage that's really giving you the definition. I mean, I understand there has to be an event to happen to cause outages. I am just trying to understand. One isn't actually saying the weather is the thing -- they are measuring it by the impacts to the distribution system.

MS. GARZOUZI: That's correct, Mr. Garner.

MR. JESUS: That's correct.

MR. GARNER: Thank you. Sorry, Mr. Rubenstein. I don't need an undertaking now that we have followed that up.

MR. NETTLETON: Mr. Sidlofsky, it's now 10:30. Might it be appropriate for us to have a break?

MR. SIDLOFSKY: Sure. Before we do, I was going to ask Mr. Rubenstein about his timing.

MR. RUBENSTEIN: Yes, well, I was just going to say back to the original question of does that undertaking be needed, the answer is no.

The original question is do we still need the undertaking, and I am answering that no, we don't.

MR. SIDLOFSKY: Good.

MR. RUBENSTEIN: And my time estimate, five to ten minutes maybe.

MR. SIDLOFSKY: Okay. Why don't we still take the break now. It's twenty to 11 on the clock in this room, we will take 15 minutes.

--- Recess taken at 10:43 a.m.

--- On resuming at 11:12 a.m.

APPEARANCES:

MR. SIDLOFSKY: Okay, we are back on the air, and we are going to continue with Mr. Rubenstein. One thing I should have mentioned earlier was, on the line we have -- sorry, we have four people: Richard Stephenson for Power Workers, Mr. Aiken for CME, Mr. McLeod for Quinte Manufacturers, and Mr. Copes for the Balsam Lake Coalition, thanks. Mr. --

MS. FRASER: And Marion Fraser for OSEA.

MR. SIDLOFSKY: Oh, thank you. Hi, Ms. Fraser.

MS. FRASER: I was a little late.

MR. SIDLOFSKY: That's okay. Oh, but while we do have you on the phone, do you have any update at all on your anticipated timing for questions? I have got you down for 20 minutes on panel 2 and ten minutes on panel 3.

MS. FRASER: I think so far most of my questions have been answered, so I -- unless there is a follow-up to one

of the questions as I hear it, I don't think I will
probably be taking any of your time.
MR. SIDLOFSKY: Thank you.
MS. FRASER: Okay.
MR. SIDLOFSKY: But you are welcome to.
MS. FRASER: Okay, thank you very much. I appreciate
that.
MR. SIDLOFSKY: Mr. Rubenstein.
CONTINUED QUESTIONS BY MR. RUBENSTEIN:
MR. RUBENSTEIN: Thank you.
Just before the break we were -- I was clarifying with
you that, as I understand it, how you determine the outage
data is, an asset stops working, and you then -- you -- so
a pole or a line, and then you determine from that, you
pick a cause code for the outage, and there are eight cause
codes, and you will determine based on why it occurred; do
I understand that correctly?
MR. JESUS: That's correct.
MR. RUBENSTEIN: Now, my fist question about that is,
with respect to the cause code for loss of supply, do I
understand that to mean -- so when we talk about loss of
supply, are we just talking about any loss of supply
upstream from that asset, or is it only transmission loss
of supply?
MR. JESUS: A transmission loss of supply.
MR. RUBENSTEIN: So say there's a transformer station
outage. This will then cause downstream outages. What do
you classify -- or do you even classify outages of the

downstream infrastructure?

MR. JESUS: So if the root cause was loss of the station, then it would be classified as a loss of supply from transmission point of view.

MR. RUBENSTEIN: Say it's a transformer at a substation.

MR. JESUS: Sorry, sorry -- transformer at a substation that results in a loss of supply at a TX-owned substation?

MR. RUBENSTEIN: No, no, let's just say there is a transformer at a substation, there's an outage there. That will obviously cause downstream outages since now no electricity will flow downstream from it. How do you classify the outage on the downstream, or do you on the downstream infrastructure?

MR. JESUS: So it would be classified as loss of supply, and it would not be counted, it would be categorized as loss of supply.

MR. RUBENSTEIN: Even if that loss of supply is not transmission-related? So say you have a distribution outage at a substation, a distribution asset.

MR. JESUS: Okay. Then it would not be categorized as loss of supply, it would be considered a station outage, and we would count it, and it would be considered as depending on the root cause whether it's defective equipment or whatever else, whatever other cause code there is. But if it's distribution-owned it would be counted. If it's transmission-owned it would not be counted.

MR. RUBENSTEIN: No, I understand for the station, but now there is an outage on downstream infrastructure from that station. Do you classify that at all or do you consider that an outage on the poles that are downstream and the line that's downstream? Because now obviously there is no power running through those.

MR. JESUS: So each one of those would be categorized differently, so there may be different outages downstream, and each one of them would have their own interruption. If you are saying there's a root cause at the station, it would be counted, and we need to address the root cause at the station, if there's further downstream outages they would also be categorized appropriately.

MR. RUBENSTEIN: But if there's no further sub -- there's a sub -- I will use an example; right? There's a substation outage. This will now cause no electricity to flow through the line -- potentially through the line that's downstream. There's a bunch of poles downstream and a line. Do you classify because there is now no electricity flowing an outage to those lines and poles?

MR. JESUS: So as again I reiterate, if it was transmission-owned that caused the outage at the substation, that caused an interruption to the flow of power, then it would be categorized as loss of supply. If that originating station is a distribution-owned station, then we would count it and include it. It would not be categorized as loss of supply.

MR. RUBENSTEIN: So which category would you give to it? I'm just --

MR. JESUS: Whatever was the root cause. So if the transformer failed it would be defective equipment.

MR. RUBENSTEIN: Even for the downstream outages, because it's not that asset that --

MR. NETTLETON: Sorry, Mr. Rubenstein, Mr. Rubenstein, you keep coming back to the downstream outage, so maybe it's not clear that if -- and I am just listening to this exchange, but it sounds like if the root cause, as Mr. Jesus is saying, is that the -- precipitates the outage happens at a distribution-owned substation and but for that outage there would be power and there would be no interruption in service to downstream distribution customers, what I heard Mr. Jesus say is that the task at hand is to classify the outage of that substation equipment that gave rise to the failure.

MR. JESUS: Yes.

MR. NETTLETON: So it's not that as a customer on that line I am -- that I am suffering an outage because I don't have power. What I heard from Mr. Jesus is that's not what they classify. What they classify is the cause of the outage, which is the substation failure.

MR. JESUS: So we classify the outage -- you are correct, Gord, we classify the outage, but it's really what is the root cause, so if's there's downstream outages as you're -- like, you keep -- I am interpreting, Mr. Rubenstein, that there outages at the substation and there's outages at the downstream. There's not?

MR. RUBENSTEIN: No, my question is just simply this, and maybe I -- let me just start at the beginning, and I am wrong at the front end here.

MR. JESUS: Okay.

MR. RUBENSTEIN: If there is a problem with a substation, a bunch of things -- down the line there's no electricity that will flow potentially down the stream and there's a bunch of infrastructure downstream, do you consider that -- do you only classify an outage and the asset that relates to the outage the substation, or do you then say, well, there's also an outage at the pole 1 and pole 2 and pole 3? If the answer is no, then that solves --

MR. JESUS: The answer is no. We would not do that.

MR. RUBENSTEIN: All right.

MR. JESUS: We would only classify it as the root cause, which would be at the station.

MR. RUBENSTEIN: Thank you very much.

Can I then ask you, when you talk about tree contact, is that the same -- when we talk about outages caused by tree contacts, is that the same as vegetation management-caused outage?

MR. JESUS: Yes, it is.

MR. RUBENSTEIN: And so when we were talking back at that SAIDI/SAIFI projections at Table 52 and 53 and corrected in the Energy Probe interrogatory, where it gives you a number for vegetation management, will there also be vegetation outages included in the other assets? Because I see you have the other three pole stations, other line components are asset-based, and vegetation management is sort of a cause code type outage.

So is there a chance that some of these outages, the 7,000 outages a year in vegetation management, are also the cause code for the outages for poles, stations, and other line equipment as well?

MR. JESUS: No, sir.

MR. RUBENSTEIN: So you have removed from the cause codes for the outages for pole stations and other line equipment, tree contacts?

MR. JESUS: That's correct.

MR. RUBENSTEIN: So if I -- when I go to 24-AMPCO-13... If we go Table 14. Is it AMPCO 13? Sorry, maybe I gave you the wrong IR. 24 AMPCO 13, page 6. I guess there's multiple Table 14s here?

When I look down and I see -- so as I understand what this table is, these are all the -- every time you are utilizing a cause code in any given year for an outage.

MR. JESUS: That's correct.

MR. RUBENSTEIN: And I see under tree contacts eight -- you know, we are talking 673,000, going up to, you know, 813,000. How does that relate to the outage numbers we get -- I think we were in the 7-8,000s in the scorecard and the corrected Energy Probe. What is --

MR. JESUS: What's the difference?

MR. RUBENSTEIN: Yes.

MR. JESUS: So the difference here is you -- the question was asked to provide the number of customer interruptions. That means every customer downstream that is being impacted is being counted in those tables.

MR. RUBENSTEIN: Okay. So that's outage times essentially. All right, thank you.

So lastly, I provided your counsel with a table earlier last week, and I've provided a copy. I am wondering if we can just mark that as an exhibit.

MR. SIDLOFSKY: That will be KT 3.2.

EXHIBIT NO. KT3.2: SEC/AMPCO ASSET TABLE

MR. RUBENSTEIN: I had discussions with you over the break about this. And this one is on behalf of both myself for SEC and Shelly Grice on behalf of AMPCO.

We were wondering if you could complete this table as best that you can. And what we are trying to do here is map not just dollars, as you have broken it down in this table, but the -- breaking down the dollars, but also the assets that are being replaced. Because as you know, assets are being replaced under a number of different programs.

I was wondering if you could take it and do the best you can. And if you can't do things, you will explain you don't have the data or whatnot.

MS. GARZOUZI: Mr. Rubenstein, we are unable to produce the table as requested. In the filing, we describe the units, the historical units for the programs that are evidence, like the wood pole replacement program, the station refurbishment program, the components and so on and so forth.

They are found in the evidence and in various tables throughout the IRs. But to reproduce this table as requested would not be possible; we don't report it this way.

MR. RUBENSTEIN: So you provide, say on a going-forward basis -- well, wood poles may be the one that actually you can map both ways. But for other programs, where you've changed the way you have done -- my understanding is you have changed the way you have done it from the last case to this case.

MS. GARZOUZI: Which program in particular would you like information on?

MR. RUBENSTEIN: Well, if we go to 24-SEC-42, I will just give you the background of why this table was asked.

So here we had asked you utilizing -- if you go to attachment 1, here we had, utilizing the categories used in the last proceeding and the programs by S number, to show what the -- what you're spending in those years and what you are planning to spend. And then you refer to what I took you to is essentially the breakdown in KT3.2.

And if you go to SEC 52, attachment 29, you break down asset types. This is 29-SEC-52. So here were the assets with those programs. But you can't -- you don't provide the program spending for 2018 through 2022 on the same basis as shown, as I just took you to in SEC 42. And we are just trying to -- that's ultimately what we are trying to do here is map, on the same basis, the assets and the

dollars that are being spent -- if that makes sense.
MS. GARZOUZI: So in SEC 52, we do provide the numbers.
MR. RUBENSTEIN: But the problem is when you get to the programs because they have switched, I can't track the dollars on the same basis. I am trying to have an apple-to- apples over both periods of time. That's ultimately what we are trying to get at with the table.
MR. NETTLETON: But, Mr. Rubenstein, as the response provided in answer 42 -- sorry, the response to SEC interrogatory 42, Exhibit I24-SEC-42, the response provided was that the 2018 to 2022 forecast cannot be provided in the format presented, and the reasons for that were given.
MR. RUBENSTEIN: Yes. And that's why, as I understand, you don't classify the dollars on the same basis anymore, and in this table we are utilizing the historic programs. So this time what we attempted to do is do it the opposite, right? Let's utilize the way that you are doing it in this case and sort of try to go backwards.
MR. NETTLETON: But the level of detail here in this is far -- in your chart far exceeds what has been rolled up into the historic.
MR. RUBENSTEIN: Well, if you're -- I would be -- it would be acceptable for our purposes, I don't know how you ––
MR. NETTLETON: I guess what I am having difficulty with is that we have provided, for each of the budget categories of sustaining and development, for system access

and system renewal, we have provided the forecast budgets for lines and meters and connection upgrades. And what I am hearing you say is that you need more detail for meters, an $11 million forecast cost -- sorry, that was in 2013.

You've asked to go back all the way to 2013, and then to forecast it out all the way to 2022. So I am just mindful of the amount of work effort that would be required to do this.

MR. RUBENSTEIN: Well, let me ask it this way: Are you able to take the 29 SEC 52 table, where you have the assets broken down like this, and provide wherever you have assets for the 2015 to 2022 period, the dollars associated with those assets? Can Hydro One -- do you have the data to be able to do that?

MR. NETTLETON: Sorry, you are in SEC 52?

MR. RUBENSTEIN: Yes, the one on the screen.

MR. NETTLETON: And you are asking which line items?

MR. RUBENSTEIN: So wherever there are asset numbers for 2015 to 2022, so the highlighted areas, are you able to provide the dollars associated for each of those years, for each of those assets?

MR. NETTLETON: Isn't that no different than just asking the question of can you provide a breakdown for each of the line budget forecasts?

MR. RUBENSTEIN: The problem though, as I understand it, is the line budgets per assets are not -- they are different now, so your programs have changed.

MR. NETTLETON: I am sorry, we are confusing lines. So for example in this application, the 2018 lines forecast is, from your chart, $21.7 million.

MR. RUBENSTEIN: Are you on K3.2?

MR. NETTLETON: Yes.

MR. RUBENSTEIN: Yes, but I don't know what assets are underlying them.

MR. NETTLETON: So you are asking what the breakdown is of that budget item?

MR. RUBENSTEIN: On two bases: what is the breakdown of assets and the breakdown of dollars.

Ultimately, we are trying to figure out -- you are doing a bunch of work. What is the work you have been doing, both not just going forward but historical, and what you are spending on an asset basis.

MR. NETTLETON: Ms. Garzouzi, can you provide some further clarification around the nature of the forecast lines capital expenditure for 2018, to give Mr. Rubenstein some context about what the $27.1 million will be spent on?

MS. GARZOUZI: Can you please clarify this 27 million, where it's coming from? If we look at 29 SEC 52, these components are found throughout the DSP, right? So if we take --

MR. RUBENSTEIN: I think you are getting at exactly the issue, right? So previously in the last case, they were separate programs. They each had an ISD number, they were separate programs, and they had an accompanying dollar amount. And I am just trying to figure out, because now I am trying to have an apples-to-apples comparison to what you have done historically on dollars and on assets so I can determine, to be open about it, what the unit costs are, if they have gone up, if they have gone down, what's changed.

And the problem is you were able to give me the asset numbers here, but when I asked for the dollars on the same basis you said, well, we don't do it the same way, and that was what we had asked in SEC 42.

So the attempt with K3.2 is to try to go the opposite direction. Now, this is now how you are doing things. Can you break it down for both periods of time. I am trying to do it -- I am trying to figure out over both time periods the same basis, trying to have a point of comparison. That's what we are ultimately trying to get at.

MS. GARZOUZI: So the large programs, so wood pole replacement and station replacement, they're tracked on a component basis, and so the unit price that is provided that is quite evident in the application is found and is available.

There are programs where they are blended in with other activities, so there are components that could be replaced in various programs, and so our unit price would not be - would not be the -- would be an estimated unit price versus a wood pole replacement, which is -- that was the cost of that replacement or a DS replacement, that was the cost of that.

If the components are replaced throughout the various programs, we can track the component, but it's no longer the unit price of that component.

MR. RUBENSTEIN: How do you price out that -- when you are doing the work? You are doing the work integrated where you are doing multiple things. You are pricing -- you have to come to some price for an estimate of how you are going to do that work.

MS. GARZOUZI: If we have a project we will estimate the project specifically, and so we will define the route of the line and where it's going and how many components we need and we will come up with an estimate, and then we will report on the project, not the components of that project.

MR. RUBENSTEIN: Okay. I am not sure where this leaves us. So are you able to attempt to do K3.2 or not or...

MS. GARZOUZI: The table that you provided me at the break, I will be unable to replicate this table.

MR. RUBENSTEIN: Any aspect of it?

MS. GARZOUZI: Correct.

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

MR. SIDLOFSKY: Thank you, Mr. Rubenstein.

Next I have Mr. Garner.

QUESTIONS BY MR. HARPER:

MR. HARPER: Yes, actually, I will start off, and then Mr. Garner will pick up with a couple of questions.

I just had one question, and that is if you could go to issue 42, VECC 64. And here we asked about the level of vegetation management costs that would normally, according to the agreements you currently have with your telecom carriers, would have been recovered from telecom companies that occurred in 2016, and you didn't provide a response stating that you were no longer going to be doing that work in 2018.

And I guess -- and I say -- this has nothing to do with the telecom and stuff that's been excluded. What I was interested in understanding is if the work was not going to be done in 2018, I then went back to Exhibit C1, where you were discussing vegetation costs to see whether one of the reasons provided for the change between 2017 and 2018 in vegetation costs was the fact that you were no longer going to be doing work in vegetation for these third parties that you used to do, and that would therefore be an offsetting factor of what might otherwise be an increase.

I didn't see any reference in that section at all to the fact that you weren't going to be doing this work any more, and therefore -- and I was wondering, that was either, A), because it was a de minimis amount of dollars and therefore it wasn't worth talking about, or perhaps that sort of change wasn't captured in the vegetation management costs you were forecasting for 2018.

And so I was wondering if, one, if you could tell me what costs, again, back to the question, if you could tell me what costs you did incur in 2016 and forecast for 2017 to provide these services and vegetation management to telecom companies, as part one.

And then, two -- and if you don't know off the top of your head you can do it by way of undertaking.

MR. NETTLETON: Let's just have one question at a time.

MR. HARPER: Yes.

MR. NETTLETON: Okay? So let's deal with part one first.

MR. HARPER: Sure.

MS. GARZOUZI: Mr. Harper, I would defer this to the next panel.

MR. NETTLETON: Mr. Boldt is going to be on the next panel, and Mr. Boldt is very much and has been very much part of the whole PAWG, the P-A-W-G, process, and I think he is probably in the best position to address the questions that you are asking regarding vegetation management for telecom providers.

MR. HARPER: But I guess in terms of Exhibit C, which I believe this panel is responsible for, would the costs that you would have been incurring be included in the vegetation management costs line shown in Exhibit C, tab 1, Schedule 1, section 3.4? I guess it seems to me that's something that this panel, in terms of how it's reported in the OM&A spending, is something this panel should be in a position to address.

MS. GARZOUZI: So the entire cost of the vegetation management is included in Exhibit C for Hydro One distribution, that captures all costs associated --

MR. HARPER: And can you tell me when you were forecasting the costs for 2018 did you take into account the fact that this activity was no longer going on and you were no longer going to be having to provide vegetation management support for the telecom companies? Was that one of the factors you took into account when you forecast the $149.6 million for 2018?

MS. GARZOUZI: That's correct, Mr. Harper. I --

MR. HARPER: Okay. And then --

MS. GARZOUZI: -- I would add that there would be benefit to the telecom and all parties attached because of less trees fallen into the line, but the scope that was priced out included clearing the power space and not the telecom space.

MR. HARPER: And so if I want to know the quantum then we go to panel 3 for that then.

MS. GARZOUZI: Correct.

MR. HARPER: Okay. That's fine. I am just trying to parse this down.

MR. NETTLETON: I think the -- Ms. Garzouzi has pointed out that the nature of the work is different. The nature of the clearing work is now different under the veg management program that's being introduced and activities that are the focus relate to the Hydro One distribution assets, not the telecom assets, and so clearing activities by definition are going to be different.

MR. HARPER: I understand that. That's clear from the response. Okay, thank you very much.

QUESTIONS BY MR. GARNER:

MR. GARNER: Thank you. My questions are really going to go around the metrics around the plan. And the first question I have -- and without referring to an IR -- is really trying to understand the scorecard vis-a-vis what the tables in the DSP planned.

And in the new scorecard you have entered or now have these three, what I call outcome-oriented metrics from your DSP on number of lines of equipment-caused interruptions, vegetation and substation ones.

And I was just trying to understand, if I compared that scorecard to the Tables 52 and 53, which have the SAIDI and SAIFI outputs, there you have one other one in addition to those three, and that's the poles.

So in the scorecard you don't include the poles as an outage metric, but in the DSP you do. I was wondering if you could just explain to me the thinking behind that.

MR. JESUS: The reason why we only include the equipment is because we categorize outages from a reporting point of view to the equipment level. And so we are reporting based on defective equipment, which would include the poles, as well as any other line components.

MR. GARNER: Right. That's what I thought I heard you say to Mr. Rubenstein. That's going to be all in the number of line-caused --

MR. JESUS: That's correct.

MR. GARNER: Thank you.

I am just going to go to my questions now. One of the questions -- well, actually, the first question I'd ask -- and you don't need to bring it up because Mr. Rubenstein also brought it up with an AMPCO question. We asked you a question similar to AMPCO about defective equipment and categorizing of defective equipment, and your answer was, we don't go down to those sub-component levels, and I think I understand that.

What I am wondering, just as an operational point of view, when you have an outage and there's defective equipment, do the crews who fix those outages have data or input data on the nature of that outage, which may not go into the outage reporting thing, but go into another data bank.

And the reason I ask is I have heard companies like yourself come forward and say things like, you know, we have an insulator problem, porcelain insulators. So I ask myself how does one come to understand that one has that problem. One must gather up data, right?

So that just begs the question what data is collected by the crews, and how does that differ from what gets inputted into a cause code outage system. Can you help me with that?

MS. GARZOUZI: You may have heard of our move to mobiles; our field crews are now equipped with mobile devices. With the DMS upgrade, we will be pushing what we call the distribution management system mobile field client, which is described in I 23, Staff 87. And so that feedback that you are describing will be occurring. It has not been occurring yet.

MR. GARNER: How in the past was that done? How did one know -- as I said using porcelain insulators; that's an easy one that I've always heard of.

How did one know that that program was needed to be addressed, if you had a program that was going to address a certain asset type that you know was failing? How does one get to that understanding?

MS. GARZOUZI: So report outages at the cause level, at the higher level. In addition to that, we track failures. If we look at the red pine example, we noticed that this was a brand new line that was built and it failed in a storm situation and there was rot at the ground. And so that was reported through a material complaint system, that was investigated. And then we started core sampling those poles and we discovered that we had a systemic issue.

That's how we were capturing those manufacturer or equipment failures that were not normal, or not what we would have expected.

MR. GARNER: So you have a system called a material complaint system that is a database of equipment that's failing, that you then can monitor and address; is that what you are saying?

MS. GARZOUZI: Yes.

MR. GARNER: And this new mobile system is basically going to continue to input into that, but just on what you consider a more effective basis, because the crews are out there and putting it online on time sort of thing.

MS. GARZOUZI: There's a few things happening. When outages occur, we know of them and so we actually look at them. We look at this outage and if something seems unusual, we will ask questions around that outage.

We do also e-mail everyone in the company around how many customers are out, and what is the main cause of that outage. So there is various mechanisms of feedback for us to monitor outages and know if it's a normal situation, or if something requires further investigation.

MR. GARNER: Okay, thank you. You don't need to bring this up again because it's just a general question, but it's in response to I29-VECC-26 and 27, and basically the question really was something like this -- what I was trying to understand is why you couldn't create a model that was linking your investment to the asset to the potential outcome by using past data. So the idea being if you replace poles over time, and you knew your investment dollars over time, you could then monitor, let's say, defective equipment outages and then come up with some idea of how effective your investments were.

And you've basically said, well, we can't do that. But what was odd was that in the main part of your evidence, you actually do talk in similar terms about sort of projecting and probability based on investment. And in fact, your whole premise of your outages changing over time actually contemplates the same concept. You will invest and you will have impacts on your outage.

So I was just wondering why can't that be done, or what precludes it being done, or maybe it is done in some sense, where the company understands that for investments in certain categories, it's looking for certain outcomes and it has past data and it can measure the effectiveness of that.

MR. JESUS: And the reason why we can't do that, to answer your question, is because there's a lot of factors and variables that affect the reliability of supply as you've -- as we've identified in that interrogatory response, including the geography, the weather, the environment, length of supply, voltage, age, condition of assets, customer density, yadda, yadda, yadda.

So to actually identify the investment and the impact it will have on the reliability is very hard to do, because there's a number of programs actually addressing many of the investments that we are talking about.

So there may be vegetation management, there may be a worse performing feeder; they are all addressing the reliability of supply on a feeder. So to actually say we did this investment and this was -- this specific investment and we had this outcome is very, very complex and there's no way that we can do that.

MR. GARNER: Well, okay, and -- but here's my problem. If you bring up Exhibit B1-1-1 DSP, section 2.4, which is the table 52 and 51, those are the DSP tables on reliability.

MR. JESUS: Yes.

MR. GARNER: If we can just bring them to the screen? It doesn't matter that we are not using the Energy Probe update, because I am not going to go particularly to what the numbers are.

But first of all, if I look at this table, am I correct that really I'm looking at plan B minus M, that's the selected plan that's in here and the other ones are alternatives. Is that the way this works?

I am just trying to confirm that the column that's entitled B-M is actually the selected DSP plan.

MR. JESUS: That's correct.

MR. GARNER: So in this table, a I understand it, what's being said is for the investments that are going to happen over the period of the five years, you're forecasting a reduction of 7.3 in your duration of Interruptions. That's 7.3 percent I take it, right?

MR. JESUS: That's correct.

MR. GARNER: So this is my confusion, I guess, is that -- and this goes a bit to what Mr. Rubenstein was talking about earlier about calculations of this. But doesn't that imply that you are in fact running a model of some type that says for all the dollars I put in, I am going to get a reduction of 7.3, therefore I can somehow create a model that gives me an input/output kind of concept? Isn't that implied by that very statement?

MS. GARZOUZI: We talked about this is a little bit on Friday, but can we just step back for a little bit of context?

I'd like to refer you to I35-BOMA-31C. The tables 52 and 53 that you are referring to is a simplified, narrower view. The application really focuses on replacing assets that have been deemed end of life. That really is the heart of the application.

And so when we look at the wood pole replacement program, we are seeing unprecedented service life for wood poles, a high number of stations that are in poor condition, and we also talk about unacceptable reliability for specific customers.

MR. GARNER: I guess I am not seeing if -- I don't want to interrupt you, but I guess I am not seeing how that relates -- I guess the way I looked at this table is one might argue -- and I am not saying we would, but one might argue, let's say, in front of the Board that if you don't reduce your SAIDI by 7.3 percent, your DSP has failed and ergo, there should be a consequence to the utility. That's what's suggested by the figure you're putting in there, right, that you are going to achieve a result of that, right?

MR. JESUS: That's correct. And I will direct you to, I'd direct you to...

MR. GARNER: Yes, sorry, Mr. Rubenstein is clarifying to me that in the table I should be reading it that the SAIDI will be 7.3 percent and the reduction will be the 1 percent -- 7.3 percent? Am I reading -- oh, 7.3, sorry, it's not a percentage. You are right. Sorry, hours, because it's in hours, pardon me. But the reduction is the negative 1 percent; am I reading that right?

MR. JESUS: So I am going to direct you to VECC -- I29-VECC 27-A.

MR. GARNER: This is where we asked about that question, yeah.

MR. JESUS: And effectively what we are suggesting is -- and what we have proposed as part of this DSP are the significant reliability improvements that we see in A. So with the vegetation management we are proposing to reduce our reliability and the number of outages by 20 to 40 percent. The defective equipment we are proposing to reduce by 20 percent. And the planned outages and the impact of planned outages to the tune of 10 to 20 percent on each of the components that are currently driving the unreliability.

So although in Table A, B, C, and B modified we attempted to provide relative differences of the reliability, the actual reliability that we are delivering is the reliability proposed and shown here under VECC 27A.

MR. GARNER: Can I just ask you a question? When you say these figures, 20 percent, et cetera, as compared to what? What's the base I am using?

MR. JESUS: 2017.

MR. GARNER: The 2017 numbers. Thank you. Okay, thank you.

MR. NETTLETON: Mark, I think it's a really important point in terms of just Hydro One's level of comfort or level of value that they see; namely, that they're more comfortable with asset performance, asset condition, and what new assets can do in terms of impact on these statistics of reliability related to outages as compared to lagging indicators of SAIDI and SAIFI.

And the trouble -- part of the trouble has been that in the TX case, as you know, we had tried to put forward a forward-thinking reliability model, and it wasn't accepted by the Board, it was thought it was a good thought but a lot more work to be done.

So it is a bit of a balancing act in terms of, how do you forecast what your investment plan is going to do and distill it down into a level that's understandable to your customers.

MR. GARNER: I appreciate that, but I think we will go faster if we don't have the arguments here, if we just go on --

MR. NETTLETON: Not arguing.

MR. GARNER: -- to what the facts are. So --

MR. NETTLETON: It's a clarification.

MR. GARNER: -- I just -- I understand that. So -- and first of all, let me just say, if we are putting opinion around it, I actually think the indicators you put in your new plan are quite good, and we asked for them, and the ones in your scorecard are real steps forward, so don't get any of us wrong about the way we feel about the improvements you are making.

But I do want to know where -- as Mr. Nettleton is saying -- where the next improvements are coming from, right, in that. So when we said could you do this type of work, and you said -- and then we asked do you know of anybody doing it, I think in response to that question you said you didn't, but then I did a little bit of my own, you know, looking into this, and there does seem to be some work that's done on the idea that you can model based on investment forward stuff, you can put weather, for instance, as you say, all of the other stuff, and you can do modelling that actually tries to give you projections in that fashion.

Have you done any research into that area about trying to model investment dollars and outcome?

MR. JESUS: We have not.

MR. GARNER: Okay. That's fine.

MR. JESUS: And I would suggest to you that most utilities do not -- can't do that kind of work because of all the variables that are impacting the outcome.

MR. GARNER: Oh, Mr. Jesus, we always expect you guys to be the leaders in these things, so I think...

Now --

MR. JESUS: I like that too.

MR. GARNER: Yeah, sorry, I am just going to find the next one I have here. I am just trying to find your reference. I think what I will do is jump to something -- well, actually, maybe it's I VECC 18. We don't need to pull it up again. It's, when it comes to these scorecard issues you are doing a reporting on them, but there's no -- I shouldn't say there is no -- is there a consequence to not meeting a target? Your target in the DSP seems to be an annual target -- sorry, a period target, five years. It doesn't seem to be an annual target. Is -- first of all, is there any annual target in the DSP to those Tables 51, 52 to meet an annual sort of number?

MR. JESUS: Yes, they are provided -- the year-by-year targets are provided in SEC -- I24-SEC-29.

MR. GARNER: Yes. And what's the impact of meeting or not meeting those targets for the company, the employees, for -- what's the meaning of it, so to speak?

MR. JESUS: So at this point in time there are no penalties that I am aware of. But we take it very, very seriously. We report reliability on a monthly basis. We are monitoring the reliability. We have developed new programs to address reliability, and we're -- we're actually -- from a monitoring and managing point of view, what gets monitored gets managed.

MR. GARNER: Yeah, let's -- that's where I wanted to go. Let's take it away from penalties and benefits. Let's talk about inputting into the next year's, let's say capital plan. Is there any feedback loop of meeting the metric and going back into the capital plan and adjusting it?

MR. JESUS: So from a scorecard point of view, from a penalty point of view, if we missed those targets, then management, from an STI point of view, we are not compensated. So there is penalties from that perspective. Absolutely.

MR. GARNER: And the other question, though, about whether there is a feedback loop in the actual capital planning, that's the one I am interested in. Is there sort of a way that that metric becomes informative of the next year's plan?

MR. JESUS: Sorry, can you --

MR. GARNER: Well, I'm sort of looking --

MR. JESUS: -- repeat your question? Can I understand your question better? Can you repeat it, please?

MR. GARNER: Well, yeah. Is the metric outcome at all informed of the next year's plan? So when we are looking at the metric, let's say, of lines in that -- in the -- it wasn't coming in the way you thought it would. Would you step back and say, okay, something is not working as well or as good as we thought, and we should look into this and adjust the plan in any fashion? Is there any feedback loop to those things, is what I am asking.

MR. JESUS: So on a monthly basis we are monitoring all of the programs and all of the reliability associated and adjusting accordingly.

MR. GARNER: Okay. Can I go to I20-VECC-20. This is a question about the regional operation of Hydro One. And it was about basically getting SAIDI/SAIFI reliability data. And I think we asked, you know, do you do it by region, and we asked you a bit more about what the regional structure was of the utility.

And if I understand the response, it says, well, we don't do our SAIDI/SAIFI by region, but maybe you can help me how the regions work. Do the regions work in the sense of reporting their own data back to the Toronto office, so to speak? Is that how it works?

MR. JESUS: No, they do not.

MR. GARNER: How does it work then?

MR. JESUS: So the reporting -- the monthly reporting is provided from our operating centre, that is then vetted through my team in planning, and then we provide all the various reports. The regions do not do any self-reporting.

MR. GARNER: I see. So they -- and, now, about the capital plan, as you do this -- you know, we have been talking the last two days or the last many days about the capital plan. How is that divvied up, so to speak, by the region? Do the regions actually have any input -- does it make a difference to the region? How does the region at all inform the plan? Do you know what I mean? As opposed to, we need to do all these poles as opposed to, let's say, Region 1 has a particular issue or Region 2 has a particular issue.

MR. JESUS: So through our planning process, through the stakeholder engagement, is where we bring in our work execution teams to review the plans that we are proposing and to review the executability of those plans. So we -- at that point in time we would take the resourcing into account across the various operating centres, so-called regions, as you referred to them, and we would look at being able to carry out the work and adjustments made accordingly.

MR. GARNER: Just so we are clear, I think you refer to them as regions, right? Northern, central, eastern, and southern. Or is that the way -- is that your nomenclature of how Hydro One thinks is the company? I don't know. I mean, I don't want to put words in your mouth.

MR. JESUS: They are operating centres.

MR. GARNER: Okay.

MR. JESUS: And zones, so there's zones and operating centres, is how we refer to them, but that's okay.

MR. GARNER: Okay. So there's not a -- or maybe there is. There's not an exercise where the head of a zone or region, whatever way we are calling it, takes a looks at the distribution plan and then feed back saying that's not really going to work for us, or we don't have this, or we don't have that problem -- or whatever it is. Is there that kind of input?

MS. GARZOUZI: Two things. So one, we record defective equipment and we will record -- for example, if we have a submarine cable issue. One of the zones, which is zone 5, has many submarine cables. Zone 1 doesn't have submarine cables. So we won't be giving zone 1 money for submarine cables because they don't have any. That's an enterprise view that we have in planning.

However, once we do have our business plan or proposed execution plan, it is stakeholdered with the vice president of execution, who will look at that with his or her team and validate the execution ability of that plan.

And so we would not put forward assets for replacements in a zone, if those assets don't exist. We would have a provincial view of the units and the executability would be validated through the execution arm.

MR. GARNER: Okay, thank you.
MS. GARZOUZI: Does that help?
MR. GARNER: Yes. I am just trying to understand the independence of the zones and the way within the company they work. I am beginning to understand they don't particularly have a lot of independence in the sense that you can say to one zone -- I know it's not everybody that would have submarine cables. But you would say, let's say to one zone, you are doing this project at half the price and you are doing this project, zone 1 versus zone 2, and then have a discussion about why that happens. Or likewise, one zone saying this isn't a problem in our area even though it's a problem and you are understanding in our area this way and that way, right? That type of interaction doesn't occur, as I understand it.
MS. GARZOUZI: We would do that as well. The wood pole replacement is a good example. I am able to track it by zone. So we are able to see why one area might have a lower unit price or be more efficient, and then we would have those discussions with the zone.
MR. GARNER: Okay, thank you, that's interesting. I am just checking. I don't think I have -- Mr. Rubenstein covered almost all of my questions on this thing. So I think I have covered -- I think I have covered all my questions, so thank you very much.
MS. GARZOUZI: Thank you.
MR. JESUS: Thank you.
MR. SIDLOFSKY: Thanks, Mr. Garner. I am going to

move to Mr. Aiken for CME.

QUESTIONS BY MR. AIKEN:

MR. AIKEN: Thank you, I have two short questions. The first one is on Exhibit I, tab 29, CME number 16. The interrogatory deals with the old and new reclosers and indicates that there is no terminal number of reclose operations used for the older oil-filled hydraulic reclosers when proper maintenance is applied. And then part B mentions the 10,000 operations of the electronic reclosers with proper maintenance.

So the question is: how long would it take an average electronic recloser to complete 10,000 operations and require replacement?

MS. GARZOUZI: It really depends on the number of outages that that circuit would experience downstream of that electronic recloser.

MR. AIKEN: Is there a range you could provide? I am just looking for a high-level number.

MS. GARZOUZI: I can't comment on that.

MR. AIKEN: What's the depreciation life for these assets?

MS. GARZOUZI: Subject to check, it's in the forest report that is filed. I am going to say thirty years.

MR. AIKEN: Okay, thank you. Then my second question is on Exhibit I, tab 29, CME number 22. This interrogatory deals with replacement of smart meters and notably in 2022.

And the question I have here is after the replacement of smart meters in 2022, how many new smart meters does

Hydro One anticipate will be unable to reliably send a signal, and how does that compare with the current number of smart meters that are unable to reliably send a signal?

MS. GARZOUZI: The replacement of the first generation smart meters really begins in 2022 and then will be replaced thereafter, so outside of the filed DSP period.

MR. AIKEN: So in other words, you don't know?

MR. JESUS: Sorry, are you asking -- what exactly is the question?

MR. AIKEN: Sorry, I can't hear you when there are two people talking at the same time.

MR. NETTLETON: Can you repeat the question please, Mr. Aiken?

MR. AIKEN: After the replacement of smart meters in 2022, how many new smart meters does Hydro One anticipate will be unable to reliably send a signal, and how does that compare with the current number of smart meters that are unable to reliably send a signal?

MR. NETTLETON: So you are asking the witnesses what their forecast is of replaced smart meters that can't receive a signal five years from now?

MR. AIKEN: That's correct, and how does it compare with the current situation.

MS. GARZOUZI: I am sorry, I cannot predict that far.

MR. AIKEN: So you don't have -- you don't know whether it will be 10 percent, or 5 percent, or zero percent -- or it could be worse? Is that what I am understanding?

MR. NETTLETON: Ms. Garzouzi, could you comment on the number of smart meters today that don't -- that are unable to broadcast or send a signal, a reliable signal, and compare that to the number of smart meters that you have?

MS. GARZOUZI: Yes. So we have approximately 1.4 million meters. 90,000 of those are not on time on use, approximately. And we are experiencing a failure rate of about 2 percent right now, ongoing.

MR. AIKEN: Okay, thank you. Those are my questions.

MR. SIDLOFSKY: Thanks, Mr. Aiken. I am going to move on to Ms. Girvan for CCC.

QUESTIONS BY MS. GIRVAN:

MS. GIRVAN: Thank you. Could you please turn to tab 33, CCC 28, please? So the question was about 2017 rate base and the fact that it's higher than the approved level. And then we asked for the forecast of trouble calls, storm damage, joint use and relocation projects you can see below.

Can you tell me what the 2017 actuals were for those cost categories?

MS. GARZOUZI: Those numbers are not available yet.

MS. GIRVAN: Okay.

MS. GARZOUZI: They will be produced in April and at that time, it will be made available, the audited financials.

MS. GIRVAN: Okay. Can you tell me how you forecast trouble calls and storm damage?

MS. GARZOUZI: For the annual budget, we take a historical average to predict the future. In-year, we would look at how we are trending compared to the year before for that month.

MS. GIRVAN: So -- and also my question is: What category of your capital expenditures are trouble calls and storm damage? Where are they contained?

MS. GARZOUZI: They would be in DSP, B-1-1, section 3.6, system renewal.

MS. GIRVAN: So they are system renewal?

MS. GARZOUZI: Correct.

MS. GIRVAN: And so in setting the amounts for 2018, you would have taken an historical average?

MS. GARZOUZI: Correct.

MS. GIRVAN: Okay, thank you. If you could please turn to tab 33, CCC 31, please. So I am trying to understand -- this is with respect to the acquired utilities. And it says that Hydro One's planning on spending 7.8 million and 8.1 million on capital in the years 2018 to '20 for the acquired utilities, and then it says the majority of the spend planned for the acquired utilities is program work.

Can you explain to me what "program work" is relative to other work in this context?

MS. GARZOUZI: It would be replacement of components, pole trans, wood poles, line components, versus a project that would be to expand a line and tie it to another circuit, for example.

MS. GIRVAN: So you haven't done any business cases for these expenditures?

MS. GARZOUZI: That's correct.

MS. GIRVAN: And how do you decide whether these expenditures are appropriate?

MS. GARZOUZI: I missed the last part of your --

MS. GIRVAN: How do you decide whether these are appropriate expenditures? So how do you make a case that this 7.8- and $8.1 million is an appropriate level of expenditure?

MS. GARZOUZI: We took in feedback from those utilities in addition to our practices, how we would maintain assets, what expected life we would expect, and we've incorporated that for those utilities.

MS. GIRVAN: So you have done sort of a grassroots forecast for those utilities?

MS. GARZOUZI: Yes.

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

If you could please turn to tab 38, CCC 39, please. And this compares your OM&A expenditures related to sustainment, development operations, customer care, for the years 2015 to '17.

And could you help me with respect to sustainment, why we see in each year a significant variance between the original budget and the actual budget?

MS. GARZOUZI: I am going to refer you to C1-1, tab 2, sustaining OM&A for the variance explanations. On page 3, we have a table that breaks out stations, lines, meters, and vegetation management. And then section 2 has a year-by-year explanation for the variances.

MS. GIRVAN: Okay. So maybe then I can turn you to tab 38, Schedule 41, CCC 41. And it does talk about vegetation management, and what's not clear to me is if the variances related to improvements in the vegetation management work -- I guess I am really trying to understand the variance with respect to vegetation management, because it implies in this answer that the underspending or the spending less than forecast was due to improvements in the vegetation management practices.

MS. GARZOUZI: This program has been improving quite a bit. There's really three strategies that were employed. There is the previously filed way, which was that wider corridor with the eight-year clearance which was found in the previous rate application. Then there was what was filed here, which -- I am going to call it the hybrid way, which has the tactical and the cycle clearing. And then there's Exhibit Q, which is the three-year cycle that we describe.

Productivity has been front of mind for this program. We have been actively seeking ways to be more efficient in our approach, and between 2015 and '17 you are seeing the three ways and the migration.

So I would say we have been more productive. If you refer to AMPCO 45, so I-38, AMPCO 45, we see the forecasted units against actual for the program. And there's really three things that have allowed us to be more efficient or more productive. Our change in strategy, certainly, our employment of equipment to help us, feller buncher and so on, our inclement weather policy, and our optimization of the brush control program.

But we see from this table in part C that we have been able to achieve the line-clearing component of this program, and we have traded off brush control and the hazard tree in some instances year over year.

MS. GIRVAN: Okay. But then in 2018 we are seeing an increase in the budget for this program; can you explain that to me?

MS. GARZOUZI: Correct. So what we are proposing in Exhibit Q is the optimal cycle protocol, which is to cycle through the province on a three-year cycle and, based on a statistical sample of what that would cost us, we believe that we need $150 million to achieve that cycle to clear the backlog and achieve the three-year cycle.

MS. GIRVAN: Okay. And just -- sorry, I am just trying to understand the sort of dynamics of this. You talk about backlog. What's that backlog? What do you mean by "the backlog"?

MS. GARZOUZI: The definition of "backlog" is any tree that is dead, dying, or diseased or a tree that can grow into the line within the planning -- within the cycle period, which is now three years.

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

MR. SIDLOFSKY: Thanks, Ms. Girvan.

The clock on the wall says about 20 after 12:00. We are going to break for lunch at 12:30, and I understand, Mr. Yauch, you have got about ten minutes of questions?

MR. YAUCH: Yeah, we will try to keep it within ten minutes.

MR. SIDLOFSKY: Thank you.

QUESTIONS BY MR. YAUCH:

MR. YAUCH: If I could take you first to tab 18, Energy Probe IR number 16. This question was punted to you. I was wondering if you were able to break down this chart into operating and capital, separate them, if that's possible.

MR. JESUS: Yes, we can.

MR. YAUCH: And what is direct costs? I mean, what are we -- what's not included --

MR. SIDLOFSKY: Sorry, just before you go on we should --

MR. YAUCH: Sure.

MR. SIDLOFSKY: -- give that an undertaking number. JT3.11.

UNDERTAKING NO. JT3.11: WITH REFERENCE TO IR ENERGY PROBE NO. 16, TO BREAK DOWN THE CHART INTO OPERATING AND CAPITAL, SEPARATE THEM, IF POSSIBLE; TO DEFINE WHAT OM&A AND CAPITAL IS BEING INCLUDED.

MR. YAUCH: What's not included when we say "direct costs" in this chart?

MR. JESUS: So these are the system renewal costs, if you will, and the system access and system service costs that would be reflected in there.

MR. YAUCH: So would things like corporate common costs be included in this figure, or not?
MR. JESUS: I'd have to check.
MR. YAUCH: Okay. Could you include that in the undertaking, if that's possible?
MR. JESUS: Sure. I will define what OM&A and capital is being included.
MR. YAUCH: Thank you. If we can go to the next exhibit, it's Energy Probe number 17, and it's literally the next IR. Now, you had a long talk with Mr. Rubenstein about this. I just want to make sure -- oh, no, sorry, that's the wrong. Are we going to update this chart to include 2017 actuals, or was that part of the undertaking you had with Mr. Rubenstein? I wasn't clear.
MR. JESUS: No, it's not.
MR. YAUCH: Is that possible, or do we not have that data yet?
MR. JESUS: We would be able to reproduce it to include '17, sure.
MR. YAUCH: We can talk at break. If you can include it in Mr. Rubenstein's undertaking, we don't have to -- or do you want a separate one?
MR. RUBENSTEIN: I didn't ask for it, so.
MR. JESUS: We didn't have a taking in the end for that; there was no undertaking.
MR. YAUCH: Okay. So we can undertake to do that, to update it with 2017 actuals?
MR. SIDLOFSKY: Undertaking JT3.12.

MR. JESUS: Okay.

UNDERTAKING NO. JT3.12: TO UPDATE THE TABLE AT ENERGY PROBE IR 17 WITH 2017 ACTUALS

MR. YAUCH: If we can go to tab 25, Energy Probe 51, and if we can go to attachment 3, please. So this is concerning the Leamington project. Maybe you can direct me where in the evidence, but there is a significant cost Overrun. It was supposed to be 19 million and now the cost is over 33 million for the project. Is there more to why it went so far over budget? Is there another document, updated business case, or is this all we have on this project?

MS. GARZOUZI: There are two components to this. There are the circuits supplying Leamington and the Leamington area, and there is the tie to Kingsville circuits which Kingsville is an over-loaded TS. So part of Leamington was to offload Kingsville and that was to achieve these ties.

So that total cost that you see is for all those circuits.

MR. YAUCH: Okay. In this business case, it says for example the variance was compounded by an estimating error related to the application of overhead, interest and contingency.

I am just curious if the cost overrun we are seeing here is a result of new scope, or it's a result more of an estimating error at the beginning. So I couldn't find anything else on the project, so I was curious if this is all we have.

MS. GARZOUZI: This area has boomed much faster than we expected. The growth has been very, very high, and so there has been additional scope, more circuits. We are expecting to almost fully utilize the TS much sooner than anticipated, and so the build was accelerated for the line work.

MR. YAUCH: Okay. My colleague, Tom, has a couple questions, too. Thank you very much.

QUESTIONS BY MR. LADANYI:

MR. LADANYI: Good afternoon. My name is Tom Ladanyi and I am a consultant to Energy Probe. I think all my questions will be for Ms. Garzouzi.

So if you could turn to Exhibit B 1-1-1, section 3.8, and the easiest possible way to find it is on page 2654. That's the bottom page, SR 14, advanced meter infrastructure hardware refresh.

The page number at the bottom is 2654 of the document, ISD document, and it's B 1, tab 1-1, section 3.8. Is SR 14 advanced meter infrastructure hardware meter refresh project -- or program, rather?

MS. McKINNON: I am still struggling to find it. You said page 265?

MR. LADANYI: 54 of 2930. I think we are there. Okay, thank you.

Just a very simple question at the beginning: why is this called refresh and not a program? Why is it called refresh?

MS. GARZOUZI: I would say it's style. So it is a program.

MR. LADANYI: Okay, very good, thank you. So you mention here that there's 1.3 million retail revenue meters, and in your answer to Mr. Aiken just a few minutes ago, you mentioned 1.4 million. And then you also mentioned that from that, we subtract 90,000 meters that are not on time of use.

So what does that mean, "not time of use"?

MS. GARZOUZI: What I mean by that is that those meters are not giving us samples to the rate -- hourly samples. And so we are able to receive billing information, but we are not obtaining communication reliably enough to be able to sample that meter hourly.

MR. LADANYI: So does it mean 90,000 are, let's say, permanently not functioning the way you would like them to function? Is that right? Or have you abandoned those meters?

What is your plan with those 90,000 meters?

MS. GARZOUZI: Can you repeat your question, please?

MR. LADANYI: I am trying to understand. Are you satisfied, let's say, with 90,000 meters not being able to be used for time of use? Or are you planning to make them function the way time of use should function?

MS. GARZOUZI: We have assessed these meters quite a bit and the economics of getting them, in the short order, communicating as frequently as the others is not worthwhile. And, so, we will catch them on the next round of replacements.

MR. LADANYI: So the next round is beyond this test period, is that right?

MS. GARZOUZI: Correct.

MR. LADANYI: Okay. So further on in this document, you mentioned seal expiry. What is seal expiry? This is in the first bullet point.

MS. GARZOUZI: That refers to Measurement Canada expiry.

MR. LADANYI: And how often do these seals expire?

MS. GARZOUZI: I don't know.

MR. LADANYI: I hate to ask for another undertaking, but perhaps you can put it on. It would be interesting to know. Can we have an undertaking for that? And the undertaking should really explain --

MS. GARZOUZI: If we can verify at the break and get back to you, I am sure we can get that number.

MR. LADANYI: Okay, very good, no undertaking required. Let's keep going down.

On the next page, there's talk about non-standard installations of acquired utilities. So what does that mean? It means it does not meet Hydro One's standard, but the meters still work? Can you explain that? Or they don't work at all?

MR. NETTLETON: Tom, could you repeat your question and also just help us where in the response you are referring?

MR. LADANYI: I am referring -- it's not in a response, it's in evidence. It's on top of page 2 of 4. It says "upgrade wholesale meter installations or acquired non-standard meter installations to Hydro One Distribution's current retail revenue meter standard".

MR. NETTLETON: Sorry, okay. We have got the bullet point reference. And your question is?

MR. LADANYI: It's a general question. Is this just a standardization initiative or are these meters not working? And why would you need to standardize if they are working?

MS. GARZOUZI: I am not sure what this is referring to. MR. LADANYI: Okay. Did you want to also tell me after the break --

MS. GARZOUZI: Yes.

MR. LADANYI: -- or did you want an undertaking?

MS. GARZOUZI: We can find out.

MR. LADANYI: Okay. I don't want to give you a hard time.

Let's keep going down now. I see a table of number of meter upgrades replaced. And we have three years of 341 meters, that's actual individual units, and then we have some four-thousand-and-something in 2021 and 206,000 in 2022.

So let's start like this. What is 341? How do you determine that number? Is that -- and perhaps I'm trying to get a -- you said it was a 2 percent failure rate, and is that 341 2 percent of 1.4 million; is that what it is?

MS. GARZOUZI: We replaced more than what is shown in this table.

MR. NETTLETON: Tom, why don't we stop. I see it's the lunch break, and those are good questions, and why don't we add that to the list of clarifications that can be done over the lunch break, and we can get back to you.

MR. LADANYI: All right.

MR. SIDLOFSKY: Okay. So we will break now, back at 1:30, please. Thank you.

--- Luncheon recess at taken 12:35 p.m.

--- Upon resuming at 1:40 p.m.

MR. SIDLOFSKY: Okay, we are going to begin by finishing off with Mr. Ladanyi.

MR. NETTLETON: Mr. Sidlofsky, over the lunch break, I think Ms. Garzouzi was going to look and see if she could help Mr. Ladanyi with clarifications regarding metering and it was an interrogatory -- the number escapes me right now.

Ms. Garzouzi, do you have some update to provide Mr. Ladanyi?

MS. GARZOUZI: Yes, I do. Hello, Mr. Ladanyi. We were losing steam there before lunch. We are energized and fed and ready to go.

So on your question around the accreditation of the meters, we do that on a six- to ten-year basis -- sorry, we do it every six years or ten years, depending on the type of meter. The six year ones are the ion meters and the rest are the ten year sampling rate.

Your question regarding SR 14, if we could go back to SR 14, ISD SR 14, you were inquiring about the number of meter upgrades replaced in the table which we were seeing,

341. Admittedly that was a very low number, so I was a little bit puzzled too. I think there was four places I would like to point you out to get the full metering picture.

SR 14 is one, and that's the wholesale standards retail meters or the 600-volt self-contained meter which is are described in the ISD.

The other view is SA 02. These are the retail meters that are replaced based on failure resampling rate. The next one is SA 03. This count is AMI network expansion. And the next one is SS 01, which is remote disconnect program.

And so the sum of these four ISDs gives you the full picture. I can point you to I 24, AMPCO 25. At the very bottom of the table, AMI, if you add those four ISDs, they will add up to the total line, the "all" line that you see here.

MR. LADANYI: Where is the total line? Which line is it in?

MS. GARZOUZI: AMI, the top line, "all".

MR. LADANYI: The one that starts with 65,600; is that it?

MS. GARZOUZI: That's correct. Is that helpful?

MR. LADANYI: Yes, it is. We will study those and we might have further questions during the hearing.

MS. GARZOUZI: Wonderful, we will welcome your questions.

MR. LADANYI: That's all for me.

MR. SIDLOFSKY: Thank you. Mr. Buonaguro?

MR. BUONAGURO: I don't have any more questions for panel 2.

MR. SIDLOFSKY: Thank you. Mr. Brett, you have got a half hour.

MR. BRETT: Yes. Perhaps a bit less, but we will see.

MR. SIDLOFSKY: Go ahead.

QUESTIONS BY MR. BRETT:

MR. BRETT: Good afternoon, panel. I'd like you to turn up BOMA 31 -- 35-BOMA-31, please. You discussed this briefly this morning with one or two of the other questioners, who have actually covered a good deal of what I was -- or some of what I was going to have.

If you look at -- I want you to look at C and in particular your answer to C. C reads:

"Given the results of the customer engagement summarized here, please provide an analysis of why plan C was not chosen."

So forgetting the editorial part of the sentence, let's go to the answer that you provided, and it's an interesting answer. It talks about a reference to SEC 4, 3-SEC-4, which we will leave for the moment.

And then you stated:

"Management concluded that plan C was not a viable option due to material and reliability system impacts. Key short comes to plan C are, (1), replacement levels resulting in an unprecedented service life for poles."

And I want to explore that a little bit just that C(1). And you go in the paragraph below to explain that the plan C results in -- replaces poles at a rate that results in an unjustifiably long service rate. A little further down in the same paragraph:

"As Figure 1 demonstrates, plan C lowers the pole replacement rate to a level which assumes a planned life for poles of approximately 107 years."

That's a fairly optimistic view of the world.

And then over on the next page 3 of 7, you have a graph that shows the 107 years. And I guess what I would -- my first question is: could you explain to me, either verbally here or by way of some written undertaking, what the arithmetic is that gets you from the rate of pole replacements that would be done on plan C to the 107 years.

And maybe as a starting point, could you tell me -- and you can explain this as you see fit. I am not trying to put words in your mouth. But as a starting point, can you tell me what the number of pole replacements is planned to be for the B modified proposal, which is your proposal over the next five years, each of the next five years, versus what the planned pole replacements under plan C would be over the next five years?

MS. GARZOUZI: Mr. Brett, you had several questions. I will try my best to answer them.

MR. BRETT: Sure.

MS. GARZOUZI: Plan B modified calls for 72,000 wood

poles over the five-year period.
MR. BRETT: And is that -- if I may just stop for a second, is that an equal amount five times? What would that be each year?
MS. GARZOUZI: I could point you to the evidence for the year-over-year, but it is not in equal amounts. It actually starts -- in 2018, it's lower and it ramps up over the five-year period.
MR. NETTLETON: Do you have an interrogatory?
MS. GARZOUZI: I have a reference, yes. Tab 29, AMPCO 27.
MR. BRETT: Right.
MS. GARZOUZI: Part B outlines the wood pole replacement per year for every plan.
MR. BRETT: Okay. And part C; is that?
MS. GARZOUZI: Correct. So your question was comparing Plan B modified to Plan C?
MR. BRETT: Okay, let me just make a note of that. I see that. Okay. That's helpful.
MS. GARZOUZI: Hence over the five-year period Plan C would replace 45,000 poles.
MR. BRETT: Right.
MS. GARZOUZI: And Plan B modified 72,000 poles.
MR. BRETT: Right. Now, my next -- my -- the second question there -- and maybe I asked more than two, but my second question was, you know, how do you get to the -- in the Plan C scenario -- well, let's go to the chart, perhaps, on page 3 just to get everybody centred on this.

What you -- what -- I think -- correct me if I am wrong -- I think that that chart is showing that under the Plan B modified --

MR. NETTLETON: Sorry, what IR -- where are you?

MR. BRETT: This is 35-BOMA-31, same IR. All these questions will revolve around the same IR.

MR. NETTLETON: Okay, thank you.

MS. GARZOUZI: Okay.

MR. BRETT: And that graph shows a planned -- shows the level of replacements under -- pole replacements under Plan B modified will result in a planned or an expected service life of 72 years. And that is compared to a, as I understand it, a perspective service life currently of 62 years?

MS. GARZOUZI: That's correct.

MR. BRETT: And that -- the 62 years is not looking at any particular plan, it's just what it is now, essentially?

MS. GARZOUZI: That's correct.

MR. BRETT: Okay. And then the planned life, if we go to the level of annual pole replacements contemplated by Plan C, goes up to 107 years. So could you just perhaps give me the arithmetic that would get us the 72 years and the 107 years?

MS. GARZOUZI: Certainly. The wood pole replacement targets wood poles that are in poor condition.

MR. BRETT: Right.

MS. GARZOUZI: Those are the ones we can control. Within the distribution business, we replace poles for various reasons. They could fail under storm, they could be replaced because of an MTO road-widening, they could be replaced as part of an upgrade or a voltage conversion.

So just to understand this example I am going to use numbers. They won't be exactly right, but on average they will give you a sense of how we derive this.

Let's say in a given year we replace 25,000 wood poles, all programs combined. The only ones we are directing for end-of-life purposes are through the wood pole replacement program.

MR. BRETT: Okay. Maybe just pause there --

MS. GARZOUZI: And so --

MR. BRETT: If you pause there for a moment --

MS. GARZOUZI: Okay.

MR. BRETT: -- the 25,000 poles that you -- in your example, would those be all poles in poor condition?

MS. GARZOUZI: No.

MR. BRETT: Because we are introducing different variables here.

MS. GARZOUZI: Correct.

MR. BRETT: I want to keep track of them as we go along.

MS. GARZOUZI: Okay.

MR. BRETT: So the 25,000 poles in your example would be some in poor condition, but others for the other two reasons you mentioned.

MS. GARZOUZI: Correct.

MR. BRETT: Right.

MS. GARZOUZI: And so to derive the expected service life of each scenario, what we did is we said, well, in Plan B modified I will be targeting 72,000 poles over the planning period. These are known numbers, these are numbers -- these are poles that I would be replacing based on condition assessments. All the others are being replaced for various other reasons. And so for those, we assumed the average age of our wood pole population.

MR. BRETT: For the other ones?

MS. GARZOUZI: For all the other ones. So that is 38 years.

MR. BRETT: The average age at the moment is 38 years?

MS. GARZOUZI: That's correct.

MR. BRETT: Right.

MS. GARZOUZI: And that is ten years older than our peers in the industry.

MR. BRETT: Yes, I understand that. But let's leave aside the comparison for a moment, because --

MS. GARZOUZI: Okay.

MR. BRETT: -- that brings in still another factor.

MS. GARZOUZI: Another variable.

MR. BRETT: I just want to speak about you, your company.

MS. GARZOUZI: Okay.

MR. BRETT: Carry on.

MS. GARZOUZI: Okay. So for Plan B modified, we are targeting those wood poles at -- so the 72,000 wood poles are being replaced. The remainder are being replaced for various reasons. For those we are assuming that there are 38 years of age. For the ones that are at end of life, we know that they are at end of life, hence we can effect the analysis, because those are known quantities, and then we did the exact same analysis for Plan C, assuming 9,000 wood poles a year over the five years, hence 45,000 wood poles.

And so in the B modified scenario, that would mean that we would believe or we would expect our poles to live 72 years versus in the Plan C scenario 107 years.

MR. BRETT: And in each case, in the two cases, are the 72,000 and the 45,000 all poles in poor condition, or are they total poles replaced in each scenario?

MS. GARZOUZI: They are all wood poles that are in poor condition. They have been assessed and deemed at end of life.

MR. BRETT: So you are working with two -- so that set is -- that set are poles in poor condition. The remainder, though, you said earlier that you -- I just want to be sure I have this right -- that as you go forward, not all of the poles you replace are being replaced because they are at end of life or in poor condition. Most, I suppose, are.

Roughly, broad strokes, what percentage of the poles each year are being replaced because they are at end of life relative to poles that are being replaced for some other reason?

MS. GARZOUZI: 40 per cent.

MR. BRETT: 40 per cent are at end of life, or --

MS. GARZOUZI: Yes.

MR. BRETT: I see. Only 40.
MS. GARZOUZI: That's correct.
MR. BRETT: And so the total number of poles being replaced over the five-year period in the Plan B scenario is not 72,000, it's 6 -- it's 5 over 2 times 78 -- 72,000; is that correct? In other words, it's 100-and-some-thousand.
MS. GARZOUZI: I am sorry, can you repeat, which scenario?
MR. BRETT: Yeah, you were telling me that you -- under the Plan B modified you said there were 72,000 poles that were going to be replaced over the five-year period. You then said that the 72,000 represents just the poles that are at their end of life, or did I get that wrong? In other words, 72,000 poles in poor condition; right?
MS. GARZOUZI: I think you are asking how many poles do you do on total and then how much of that is for end of life; is that correct?
MR. BRETT: That right, yes.
MS. GARZOUZI: It fluctuates depending on new connections, external factors, storms, and so on and so forth.
MR. BRETT: Right. On average?
MS. GARZOUZI: I would say 25,000 wood poles in total in a given year.
MR. BRETT: 25,000 would be end of life?
MS. GARZOUZI: No 25,000 wood poles total, all programs combined.

MR. BRETT: Okay. All programs combined. So which in this case -- okay. I think that's fair enough.

MS. GARZOUZI: Is that helpful?

MR. BRETT: I think I understand that.

Would it be possible -- I mean, there are a fair number of numbers here. Let me ask one or two other related questions just to get the full picture.

Your average life at the moment of your pole population, your 1.4-million wood pole population, I understand to be 38 years; right?

MS. GARZOUZI: That's correct.

MR. BRETT: Now, my next question is: In respect of each of the two options I am looking at, Plan B modified and C, what happens to that average life of poles over the next five years? It must -- what would the numbers be there? Do you have those, approximately?

MS. GARZOUZI: Yes, just a minor correction, Mr. Brett. We have 1.6-million poles.

MR. BRETT: Sorry, I thought I -- okay.

MS. GARZOUZI: And when doing this analysis, we are assuming that our poles are aging by one year every year.

MR. BRETT: Right. That makes sense. Sorry about that question.

MS. GARZOUZI: We factor that into this to not overly inflate the numbers. So we take account the fact that there is time, there is a time component, and that's factored into this analysis.

MR. BRETT: Okay. Now, I guess what I was thinking is your existing poles are going to age at a year at a time, one year per -- one year per year, I guess. But then you are putting new poles into the mix and so you are affecting that average. You are putting different numbers of new poles into the mix. In the case of B, B modified, you putting in a certain number and in the case of C, you are putting a smaller number. But in each case, you are putting in an infusion of new poles, if I can put it that way.

And I guess I am looking at the numbers here, and I am looking at it on a very high level and I haven't studied mathematics for a long time. I did at university, but not in a long time, and it looks like those differences would be di minimis because of the small amounts of addition relative to the 1.4 million. In other words, let me try and ask it in a more common sense way.

What I was trying to get at was what's the impact of these two different programs on the average life of your inventory at the end of the period, 2022? It would be something, but it would be presumably not very large; is that right?

MS. GARZOUZI: There are more random failures than there are targeted wood pole replacements.

MR. BRETT: All right. Could you just elaborate on that a little bit? By random, you mean in a given year?

MS. GARZOUZI: Random replacements and failures combined is higher than the number of poles that are replaced due to the wood pole replacement program.

MR. BRETT: Due to them being in poor condition?

MS. GARZOUZI: Correct.

MR. BRETT: So in an average year, you might have -- I think you've told me 40 percent would be the factor.

MS. GARZOUZI: Roughly, depending on the year. That number, the 25 -- we are going with 25,000 wood poles in a given year, and it could be 19 one year and it may be 26 in another year.

MR. BRETT: Right, and 40 percent of that would be poles in poor condition you are replacing, and 60 percent would be random failures?

MS. GARZOUZI: Random or triggered due to external demand, or due to a voltage conversion, a road widening, a spontaneous failure, all those combined.

MR. BRETT: That explains a number I noticed in your evidence, and I apologize that I can't point it out, so I will ask you about it.

What I noticed was the number of -- currently, you have 109,000 poles which are in poor condition and I am assuming, just as an aside, that you run the same kind of categorization as most utilities. You have very good, good, fair, poor and very poor. So the poor and very poor are 109,000 out of 1.6 million.

Now then, the question was what would be the number of poles in good condition -- in poor condition, rather, at the end of 2002. And the number is not a heck of a lot larger. I recall a number of something like 115,000. Is that -- or let me just ask the question.

Under the both scenarios -- let me slow down a bit. Scenario B modified and C, for each of those scenarios, what would be the number of poles in poor condition that you're forecasting for 2022?

MR. SIDLOFSKY: For one of the people online, could you maybe just check your phone because you have got some awesome hold music on there. Thanks.

MS. GARZOUZI: Mr. Brett, if your question is at the end of the period, how many poles in poor condition are remaining -- is that what you are getting at?

MR. BRETT: Yes.

MS. GARZOUZI: Okay. Plan B modified maintains the number of poles in poor condition.

MR. BRETT: So it would be 109,000, the same?

MS. GARZOUZI: That's right, assuming a constant rate of poles in poor condition that are found.

MR. BRETT: Right. And plan C?

MS. GARZOUZI: Plan C would see the population of wood poles in poor condition climbing.

MR. BRETT: By how much? Do you know?

MS. GARZOUZI: I am going to refer you to the evidence, B 1, 1 --

MR. BRETT: Sorry, C?

MS. GARZOUZI: B1-1.

MR. BRETT: D as in dog?

MR. NETTLETON: No, B as in bravo.

MS. GARZOUZI: The DSP, B1-1, section 2.4, page 3. We described the number of wood poles in poor condition remaining under each scenario. So for plan C, it would be 126,000 wood poles.

MR. BRETT: Okay, that's familiar, thank you. And just one other question on this, and if you have an answer, this is a bit awkward to say.

But do you have a sense of how many poles move, let me put it this way, move into the poor or very poor category each year? In other words, you have got a population of 1.6 million poles. We know poles age and we know their condition gradually deteriorates. On average, because I am sure it will vary some from year to year, roughly how many poles does your data show become in poor condition on each year going forward? Like what's the organic deterioration, if I can put it that way?

MS. GARZOUZI: I believe it's about 6,000 wood poles a year.

MR. BRETT: Okay, thank you. Then if I can just for a moment -- I am switching gears a little bit here on to the -- but not that much. I'd like you to turn up for just a moment the IR from Energy Probe that everybody's been discussing, if I can get the right one here.

It's 18-EP-17 and it's that table 52 that you have been talking to people about this morning. And I just have a very brief question on that.

MR. JESUS: Sorry, what was the IR? Can you repeat the reference?

MR. BRETT: I believe it's 18, Energy Probe 17 -- sorry. And there should be a table, that's fine. I understand this is sort of the most recent iteration of this table; I know it appears in numerous other places. But can you just explain to me, well, on the column on the left, failure rate impact, and this gives us -- at the top, we have SAIDI average 2013 to 2016, 7.4 hours per year.

And then you look at the column failure rate/impact. could you tell me, sort of in layman's terms, what that represents? What do those statements represent? Is that some sort of a baseline, or what is that? What do I take that to mean?

MR. JESUS: Sorry, which column are you referring to? I didn't quite hear you, sorry.

MR. BRETT: I am referring to under "assumptions", the column on the left, not the far column on the left, which is poles, stations, other line components, vegetation. I'm -- the next column over to the right, which is called "failure rate/impact".

MR. JESUS: Okay.

MR. BRETT: Okay? And my question is: What do those statements represent? Like, what is that saying? How should I take that?

MR. NETTLETON: Mr. Brett, are you asking -- you mentioned the 7.4 hours metric on the top line.

MR. BRETT: Yes.

MR. NETTLETON: Did you want a clarification around what that number represents, that SAIDI statistic?

MR. BRETT: Well, that might be part of it. Is that, for example, the total of all of these outages?

MR. NETTLETON: That's the average SAIDI statistic.
MR. BRETT: Yeah, no, that I think I get. But it's the failure rate impact, those bullets, if you could just tell me what those -- what they are meant to indicate. Is that in a particular year, for example, is that a historical number?
MR. JESUS: So it's the average over that period of time.
MR. BRETT: Yeah.
MR. JESUS: And on average we are having 300 pole failures a year, impacting roughly 400 customers per outage, so every time it happens it's impacting about 400 customers and it's taking on average five hours to restore.
MR. BRETT: Thank you very much. That was giving me a lot of trouble I didn't quite grasp that.
And that sort of then becomes your historical comparison, and what you are doing then with the rest of it is showing what the impacts would be on those numbers given the various construction programs that you are talking about?
MR. JESUS: That's correct.
MR. BRETT: Okay. I get that.
And so, for example, in -- just going to the bottom for a moment, the estimated impact to SAIDI of line -- the second line from the bottom, if we go across to Plan B modified, we see an increase of 2 per cent, that's for 2000 and 22 (sic), and if we look at C we see a decrease of 2 per cent, and then the other two, there are further

increases. Okay. I get that.

I have a question that -- in the -- when we were -- going back to the original --

MR. NETTLETON: Mr. Brett, sorry, I just want to make sure, Mr. Brett, you understand the statistics that you just read out, because the Plan C is showing to have a negative 2 per cent.

MR. BRETT: Yes, I understand.

MR. NETTLETON: Right. And so I thought I heard you thought -- I thought I heard you say that that was an improvement to SAIDI; i.e., a reduction.

MR. BRETT: Well, I meant -- certainly I meant to say it's a deterioration.

MR. NETTLETON: Right, okay.

MR. BRETT: Yeah. That's what I meant by the minus 2.

Okay. Now, in the -- if you turn up for a moment School Energy Coalition, and you discussed this, I think, with others this morning. It would be tab 3, SEC 4, and attachment 2, and page 4. Yeah, I think you are there, aren't you? Yes.

Now, if you look down at the third bullet there -- first of all, could you go back, could you scroll back a bit? Okay. All right. Okay. Just hold that a second.

All right. Now, would you go back to where we were, just scroll forward? Thank you.

Now, if you look at the third bullet it says:

"Rate base/asset growth originally limited to 4.2 per cent as in the previous business plan."

Could you just elaborate on that a little bit? Is that a -- it says "originally limited to 4.2 per cent". Was that sort of a financial guideline that was given to the planners?

MR. JESUS: It's the -- referred to as the CAGR rate that's been communicated to our investment community.

MR. BRETT: Right.

MR. JESUS: And so that's what they've articulated for the company, in terms of growth rate of 4.2 per cent.

MR. BRETT: Okay. That's what you told the shareholders, basically, and the public shareholders and private shareholders.

MR. JESUS: Correct.

MR. BRETT: And that, I guess, drives then -- the importance of that to them would be that that number drives a -- effectively drives or has a significant impact on your return on capital, right, or your growth? I guess on your growth, I guess.

MR. JESUS: Well, let me put that number -- let me help you put that number in perspective in terms of what it means to the investment plan. So from an investment planning point of view, there is no target. The planners do not understand what a 4.2 per cent rate impact growth is.

MR. BRETT: Right.

MR. JESUS: They are putting forth plans and investments that address the needs of the system.

MR. BRETT: Right.

MR. JESUS: That are balanced with our customer needs and preferences.
MR. BRETT: Right.
MR. JESUS: That balance the actual rate impacts to our customers.
MR. BRETT: Right.
MR. JESUS: So for all intents and purposes the planners are focused strictly on a bottom-up approach to identify the needs of the system. In fact --
MR. BRETT: Profitability and the growth and the return on equity, essentially.
MR. JESUS: I would suggest not. I think --
MR. BRETT: Sorry, I imputed too much there.
MR. JESUS: I would suggest that from a -- the 4.2 per cent really is -- I think we have all -- in BOMA 31C, we highlight that we have a lot of asset condition needs on the system, and that if we were to address them all we would be spending way more money than the 4.2 per cent that's identified there, so it becomes a matter of pacing those investments to ensure that we are managing our rate impacts to our customers.
So in the end, in the end, that 4.2 per cent is more of a constraint than anything.
MR. BRETT: Right. That's a directive or a guideline from the senior management to the planning, to the corporation, really, to say whatever we do, we can't grow that rate base by more than 4.2 per cent. Is that the idea?

MR. JESUS: No.

MR. BRETT: Is that the way you mean "constraint"?

MR. JESUS: So I would suggest that we have more needs on the system that would overshoot that by a landslide if we were to add up all the needs and preferences.

MR. BRETT: Right.

MR. JESUS: So at the end of the day what we are trying to do is manage, as we have articulated in the DSP, that we are managing the three components: The needs of the system with the rates that we are charging to our customers, and the last piece was, I mentioned it before, was the condition and reliability of the system.

So those three things are what we are trying to balance, and it's a bottom-up approach, so for all intents and purposes the 4.2 per cent is neither here nor there.

MR. BRETT: So the 4.2 per cent is -- and correct me if I'm wrong. I may be having -- I may not quite be with you here, following you, but is that an optimized number, essentially? That's a number that takes into account all three of your objectives, or if it's something else, what is it, exactly? What is its significance?

MR. JESUS: The 4.2 per cent?

MR. BRETT: Yes.

MR. JESUS: I would suggest that it has no impact on this whatsoever, that from an optimization point of view we are again addressing the needs of the system, we are building up the plan from the bottom up, and the needs and the risks that we are mitigating for the dollars that we are spending --

MR. BRETT: Okay. But --

MR. JESUS: -- at the end of the day, they're -- that's what we are trying to optimize, is those three elements.

MR. BRETT: Okay. I am sorry. I guess I missed out here. You say originally limited to 4.2, as in the previous business plan. So that -- does that -- should I read that as saying in the previous business plan, meaning, I assume, last year's business plan you did have a growth of rate base of 4.2. It was limited to 4.2 by a sort of general -- that's just what a -- either that's just what it was or it was -- the guidance was to keep it at that level; right? Is that what that's saying? And then the notion here that in this case it was originally limited to 4.2 but now has become something else.

I guess that was perhaps the last -- the second question I would put there in this last category: What is the -- I guess the question would be, what is the increase in the rate base over the term of this proposal? It's not 4.2 per cent; am I right in that?

MR. NETTLETON: We are digging for the number, Mr. Brett.

MR. BRETT: Okay. Ms. Lee is one of the diggers, so just bear with us.

MR. JESUS: Okay. So I am going to point you to the evidence, section B 1-1, DSP section 1.1, and I am pointing you to page 4. And line 2 indicates that the immediate impact on rates in 2018 on this plan would be 5.4 per cent, and on average over the period to the five-year period would be 3.4 per cent. So if you're referring to the 4.2, it's well under that 4.2.

MR. BRETT: So actually you don't have a number there -- thank you for that. You don't have a number for the compounded rate of growth of the rate base over five years, or is that in the evidence somewhere?

MR. NETTLETON: Mr. Brett, I think we may be talking at cross purposes. I think what Mr. Jesus just read out is the overall rate impact.

MR. BRETT: Right, that's why I am asking this follow-up.

MR. NETTLETON: And I think Ms. Lee has found the comparator to the stat, so if you could, Ms. Lee.

MS. LEE: Sure. I would refer you, Mr. Brett, to Exhibit D 1, tab 1, schedule 1 -- D as in dog -- table 2. There is a distribution rate base table, although it does express the growth in rate base in dollars.

MR. BRETT: Could you perhaps just give an undertaking to give me the compound rate of growth of the rate base over the five years?

MS. GARZOUZI: Yes, we can undertake that.

MR. BRETT: Thank you very much, and those will be my questions.

MR. SIDLOFSKY: It's JT3.13.

UNDERTAKING NO. JT3.13: TO PROVIDE THE COMPOUND RATE OF GROWTH OF THE RATE BASE OVER THE FIVE YEARS

MS. GARZOUZI: Thank you, Mr. Brett.

MR. SIDLOFSKY: Mr. Ferguson for Anwaatin?

QUESTIONS BY MR. FERGUSON:

MR. FERGUSON: Good afternoon, panel. I have questions on three interrogatories of ours today. They are Exhibit I, tab 6, Anwaatin 2 and 3, and those will just be some questions we kind of skimmed over a little bit yesterday -- or, sorry, Friday, today is Monday. And then I will have questions on Anwaatin 8, which is at tab 24, Exhibit I, tab 24, schedule Anwaatin 8.

So if I could have you turn first to tab 6, Anwaatin 2, page 4, please. And this was just following up on our discussion about your joint work with EPRI, the Electric Power Research Institute. And I just think what kind of got lost in the shift there was at what point you expected the work to be complete on that report. I think Mr. Jesus --

MR. JESUS: This is on the EPRI report? What are you referring to?

MR. FERGUSON: Yes, the second last paragraph there on page 4. You discuss joint work you have partnered with EPRI to undertake the study for a Northern Ontario single circuit line assessing the technical and financial suitability for installing DER technologies to address reliability.

So we discussed that report a little bit, but what we didn't discuss was when you anticipated that report being finished.

MR. JESUS: So we are starting that work now with EPRI. We've started it as part of the NRCan proposal submission. So when we are finishing, I can't tell you that at this point in time. It's dependent on the funding and whether or not we actually receive the funding to proceed.

MR. FERGUSON: Thank you. You anticipated my next question, Mr. Jesus.

In the last sentence of that paragraph where it says, "Following successful completion of this project, the DER technologies could be applied at various parts in Northern Ontario."

I am just wondering what was meant by "various parts" there. Is there particular projects locations in mind or is this just...

MS. GARZOUZI: So once we understand the feasibility and our ability to deploy it, it will determine the use case in which we would deploy. So we would need to define the conditions by which it would be feasible and reliable, and that is where we would deploy it. That will be understood throughout the study.

MR. FERGUSON: Thank you. And the last paragraph there of the page, where you say:

"Hydro One has not undertaken any efforts to obtain, consider, integrate information from tribal utilities nor any electricity distributors in response to our interrogatory there."

I understand you haven't done so. Do you have any plans to discuss with those other utilities, or seek that information?

MS. GARZOUZI: Mr. Ferguson, can you please point us to the line specifically that you are asking about?

MR. FERGUSON: Sure. It's lines -- the sentence that starts on the end of line 34, and just for a refresher, because it's in response to our interrogatory D with the text on page 2.

MR. NETTLETON: Mr. Ferguson, I am struggling with the question because the transaction hasn't even closed yet. So I am not sure how much more they can provide.

MR. FERGUSON: I was just curious if the answer is no, if you haven't yet.

MR. NETTLETON: Well, the answer is no in this answer.

MR. FERGUSON: It says they haven't undertaken any efforts yet. I was wondering if there are any plans.

MR. NETTLETON: Right, and the clarification is that that's because the transaction hasn't closed yet.

MR. FERGUSON: Thank you. That wasn't clear from that, but thank you, Mr. Nettleton. And Ms. Garzouzi, that's --

MS. GARZOUZI: That's correct.

MR. FERGUSON: Thank you. If we can go to your response to E, where you say that you will replace assets with distribution automation assets as replacements. I was wondering what are distribution automation assets?

MS. GARZOUZI: What we mean by distribution automation assets is we are referring to assets that communicate. It could be a line recloser, it could be a sensor, it could be an automated switch. So it's a device that gives us information on the system, and ideally is able to interrupt load to minimize the impact of outages.

And if we have many of them on a circuit or multiple circuits, then they can restore amongst themselves, which we would call then self-healing.

MR. FERGUSON: Hence the automation part?

MS. GARZOUZI: Correct.

MR. FERGUSON: Thank you. So how would these assets address increasing demand for distributed energy resources? Can you give me some examples of that?

MS. GARZOUZI: One of the challenges with DERs -- if we talk about demand response, all of that is embedded within this question.

But we operate that system currently -- excluding the Owen Sound area, which is smart -- the rest of the Hydro One system is operated based on a planning loading limit and planning assumptions. When we have more intel into the system, more monitoring, more sensing, we can now start to operate the system based on operating limits. So automation is a key component to that. It allows us to know if we can enable more load or distributed generation, depending on which side you're on.

MR. FERGUSON: Okay, thank you. I think I understand. It gives you the information you need to then properly utilize those assets. Am I understanding that correctly?

MS. GARZOUZI: Correct. And increase the optimization of the system and the use of the system.

MR. FERGUSON: So it would be kind of a precursor to then installing those DERs?

MS. GARZOUZI: That's correct.

MR. FERGUSON: Thank you. In response to F, our interrogatory F, you will see the words "lessens" and "standardized" are in scare quotes. I was wondering if -- why that was. You say "based on lessons", in quotes, "from the need to rapidly connect DERs, Hydro One has standardized", again in scare quotes, and I was just -- I just found that curious, and I was wondering why those terms were in quotation marks.

MS. GARZOUZI: I think it's grammatical style of the author. I don't think there is any other explanation for that.

MR. FERGUSON: Thank you. And what would those lessons -- what are some of those -- what are those lessons? Would you be able to expand on that?

MS. GARZOUZI: Yes.

MR. FERGUSON: Thank you.

MS. GARZOUZI: I'd like to point you to I-23, Staff 87. In part A there is a table. And for demand response for DMS, for distributed generation dispatch, it describes the scope of work and the pilot results and expected benefits.

In particular, for your interest, I would point you to the last line of the table, which is demand response for operations.

MR. FERGUSON: Thank you, yes, we will review that. Thank you.

And similarly on the standardization of the DER connection process, is there anywhere in the evidence that that's described that you could point me to?

MS. GARZOUZI: The same table talks to both.

MR. FERGUSON: The same table talks to both. Okay. Thank you.

And for my last question on Anwaatin -- sorry, was there something to add there? Okay. So for my last question on Anwaatin 2 -- I got you too excited by saying it was my last question, but I understand.

[Laughter]

On this interrogatory response, the last paragraph there of page 5 of Anwaatin 2, where you discuss the joint research with utilities and organizations such as EPRI and CEATI, so you keep a watching brief on emerging technologies, and that you participate in, where appropriate, developing or updating technical standards that would effectively enable DER connections to the grid.

I was hoping you could expand on what work you've done in that -- Hydro One has done in that capacity.

MS. GARZOUZI: As I am sure you're very aware, Mr. Ferguson, we have connected a lot of distributed generation in our system. That was a great example of us working with IEEE to develop standards for DG enablement in the distribution space Ontario was leading at the time and probably still has a really high volume of penetration on the distribution system.

So the DER framework, whether we work with CEATI or EPRI, we participate in technical focus groups that explore the operational feasibility, the optimization of this technology, and how we incorporate that into normal business.

MR. FERGUSON: Any particular standards you could point me to that you have developed as a result of this work, regarding DERs in particular? Let me be specific on this matter.

MS. GARZOUZI: I can't think of a standard right now that we are participating in specifically.

MR. FERGUSON: Would you be able to undertake just to review and confirm whether they are and what they are?

MS. GARZOUZI: Yes, I can.

MR. FERGUSON: Thank you.

MR. SIDLOFSKY: That's Undertaking JT3.14.

UNDERTAKING NO. JT3.14: TO REVIEW AND CONFIRM STANDARDS ESPECIALLY REGARDING DERS.

MR. NETTLETON: Just for the court reporter, the acronym CEATI is C-E-A-T-I.

MR. FERGUSON: Thank you, Mr. Nettleton, and thank you, Mr. Sidlofsky.

If I could have you turn, please, to tab 6, Anwaatin 3, page 3. And it's your response to our interrogatory B. It's the middle of the page there. You state there are no active DER projects related to Indigenous communities, and I assume that's because the Christian Island is not yet active? Do I have that correct?

MS. GARZOUZI: That's correct, Mr. Ferguson.

MR. FERGUSON: Thank you. And the second half of that sentence you say:

"It's expected that DER lessons and opportunities are transferable to all communities."

And I was hoping you could expand on that, what you mean by "lessons and opportunities". I mean, opportunities I think we covered fairly exhaustively on Friday, but the lessons, perhaps, if you could expand on that, please.

MS. GARZOUZI: That's similar to the conversation we just had. So understanding the ideal location, the criteria by which you would be able to deploy these technologies.

MR. FERGUSON: Okay. And our interrogatory had been about whether Hydro One had taken any measures with respect to DERs and business partnerships as a means of accommodating First Nations communities that were concerned about historical, present, and future compensation for Hydro One assets on reserve. And I was wondering if Hydro One had explored these partnerships with respect to DERs as a means of addressing these issues.

MR. NETTLETON: Mr. Ferguson, I thought that response B says there are no active distributive energy resource projects related to Indigenous communities. So I am not sure how -- you know, based on the discussion you have had with Ms. Garzouzi over the past couple of days, I think Hydro One has set out what their plan is with DERs, looking at the pilot project that's being carried out, and is going to evaluate the success or not of that going forward. But I think what you're exploring is well beyond the scope of this proceeding.

MR. FERGUSON: Certainly, Mr. Nettleton, it's possible they could have explored it and not gone anywhere with it. I just wanted to see if that had been the case.

MR. NETTLETON: I think what you heard from Ms. Garzouzi about the pilot project that's underway is that there have been no firm decisions yet taken. Anyways, it just strikes me that you are exploring an area that's beyond the scope of this proceeding.

MR. FERGUSON: So is that a refusal to answer the question?

MR. NETTLETON: It's an observation, and I would ask you to refine your question so that it's relevant to this proceeding.

MS. GARZOUZI: Mr. Ferguson, can you please repeat your question?

MR. FERGUSON: Certainly. I am just considering how I might rephrase it to...

MR. NETTLETON: Your question was has Hydro One looked at DER projects as a means to facilitating any accommodation or consultation obligations regarding historic grievances, and I do take exception to the question on the basis that DERs themselves are something that's in the planning and investigation stage. So I don't think it's a fair question to say or to seek some sort of commitment from these witnesses to say, yes, it would be in the bailiwick of what Hydro One might look like. I think it's -- what you have heard from the witnesses is that there is a systematic approach that is being taken where they are going to be studying this, and it could very well be that if it's successful or not it may influence what Hydro One does in the future.

But I don't know how you could expect anything more than a wait-and-see type answer until these pilot projects are completed.

MR. FERGUSON: Okay, thank you, Mr. Nettleton.

Moving on to page 6 of Anwaatin 3. Do you have that up? Would you mind scrolling to the bottom, please, for the witnesses. Thank you.

I assume at the end of answer F there, the federal government funding is the same as what we discussed with respect to the Christian Island Beausoleil First Nation project; is that correct?

MS. GARZOUZI: That's correct.

MR. FERGUSON: For response G there you have indicated that you have partnered with EPRI and CEATI to undertake -- that's in addition to what was in Anwaatin 2; correct? The research there that you have undertaken, if I understand that correctly, it says that in the first part of the interrogatory.

MS. GARZOUZI: That's correct.

MR. JESUS: That's correct.

MR. FERGUSON: That's correct, okay. And could you describe what -- if there are any reports that have come out of this research?

MS. GARZOUZI: We have a white paper and a study that was done with EPRI.

MR. FERGUSON: Was that filed as part of this application?

MS. GARZOUZI: No it was not.

MR. FERGUSON: Would you be able to file it?

MR. NETTLETON: Mr. Ferguson, help me understand why that study would be relevant to this proceeding.

MR. FERGUSON: Well, sorry, maybe I should ask Ms. Garzouzi. Could you elaborate on the content of the report subject matter?

MS. GARZOUZI: It explores DER deployment, but it's theoretical.

MR. FERGUSON: Can you explain that a little more, please? Sorry, when you say "theoretical", do you mean it's hypothetical?

MS. GARZOUZI: It's a case study on DER within a context of a long rural feeder. Now, I haven't read it in several months, so I can't tell you if it's relevant or not at this point.

And the second thing that I am wondering is would EPRI allow us to disclose, but I am not sure of either of those at this point in time. What I can do is I can refresh on the study, and confirm the scope of the study and we could take it from there.

MR. FERGUSON: That's agreeable to me at this point.

MS. GARZOUZI: Okay.

MR. FERGUSON: I certainly think that, from our perspective, sounds relevant to reliability issues. We are certainly interested in that and if that sounds very similar to the situations that many of our clients are in, we would certainly like to see that, if possible.

MR. NETTLETON: We will undertake to review the report and provide a summary of its content. We are not committing to filing the report, particularly if there's a concern about confidentiality of it, and we can move forward on that basis.

Again, this application, Mr. Ferguson, does not rely on any DERS projects. What the evidence has been through Ms. Garzouzi is that it's an area of active investigation, it's very preliminary, and the results are still being tallied. And until that happens, it's difficult to see how it's relevant to a rate case such as what we have applied for.

MR. FERGUSON: Certainly, Mr. Nettleton. I am happy with the undertaking as given, if it's a summary and we can discuss relevance from there. I understand you haven't reviewed it in a few months, and that's perfectly fine.

MR. SIDLOFSKY: JT3.15.

UNDERTAKING NO. JT3.15: TO REVIEW THE WHITE PAPER REFERRED TO IN ANWAATIN 2 AND PROVIDE A SUMMARY OF ITS CONTENT

MR. FERGUSON: Thank you. If we can turn to tab 24, Anwaatin 8, and my last series of questions. The end of the tunnel is in sight.

So if we could turn to page 3 of Anwaatin 8, you have this note explanatory note here regarding providing five years of data, and you mention that it's because of the strict timelines. I assume that's because of the large volume of interrogatories and the short turnaround time between interrogatory submission and IR response due dates. Do I have that correct?

MR. JESUS: Yes.

MR. FERGUSON: Yes. But you do have that -- we had asked for ten years, and we were given five years. And I understand from the transmission proceeding that these reliability metrics are better viewed over a longer period of time.

We do have quite a bit of time now until the next stage in this proceeding. Would you be able to provide those other five years?

MR. JESUS: I guess part of the other reason why we didn't provide the other five years is beyond that from a reporting point of view. We can't -- I'd rather not do the six to ten years because of the reporting that's there. I want to make sure that five years is a reasonable timeline from a trending point of view.

At the end of the day, I think we can rely upon the five-year data and going beyond that, I am a little concerned, to be quite honest with you.

MR. FERGUSON: What are your concerns?

MR. JESUS: Just from a reporting point of view from the data that's there, and making sure it's all consistent in terms of how we have collected that information and how we are reporting it now.

I just want to make sure it's consistent, so that's why I have a concern to say going beyond that period of time, the consistency may not be there.

MR. FERGUSON: In what sense? Sorry, I am just trying to understand what you are saying.

MR. JESUS: From reporting, whether it's defective equipment, how we report, like all of that from five years ago, I am just a little concerned, to be honest.

MR. NETTLETON: It's ten years ago.

MR. FERGUSON: Up to ten years ago.

MR. JESUS: Yes, exactly.

MR. NETTLETON: So to summarize it's data quality and data availability, and it's still not clear what incremental value from a probative sense that type of information would have, Mr. Ferguson.

MR. FERGUSON: Sorry, did you have something to add there, Mr. Jesus?

MR. JESUS: I am sorry?

MR. FERGUSON: Sorry, did you have something to add there? It looked as though you might have something extra to add, to say.

MR. JESUS: No, nothing further.

MR. FERGUSON: Mr. Nettleton, certainly we had ten years of data in the transmission proceeding, and that wasn't a problem. I believe your witness indicated -- in that proceeding as well, Hydro One's witness indicated that a longer time frame was a better time frame, if I may paraphrase, for reviewing these trends.

And so certainly if there's data available, we would like to see it, with the understanding that there are certain caveats that Hydro One might have about that.

MR. JESUS: We can provide the data, ten years worth of data, but it's going to take time.

MR. FERGUSON: We understand that.

MR. JESUS: But you have to understand it's not going to compared to -- like, I do have concerns regarding the data quality; that's my concern.

MR. FERGUSON: And we would prefer to have the data with those concerns outlined and explained than to not have it.

MS. GARZOUZI: Mr. Ferguson, what is the question you are trying to answer?

MR. FERGUSON: Thank you, Ms. Garzouzi, I was just about to go to the undertaking. If you could update the charts in B provided. So figure B1, B2, C1, C2, D1, D2, E1, E2, G1, I1,I2 and I3. Sorry, I think those last ones are actually written as figure 1.2 and 1.3, but they should be an I.

MS. GARZOUZI: Perhaps my question is even more basic than that. So are you trying to determine a trend, are you trying to -- what is that you'd like to understand?

MR. FERGUSON: Yes, we would like the see the trends and how the communities we represent compare so similar to what we have got with the five years here. We were happy to get that. But we had asked for ten and if the data is available, we would like to see that.

MR. NETTLETON: So, Mr. Ferguson, one of the challenges that we seem to be having is the analogy that's being used that what happened in the transmission case dictates what happens in the distribution case.

I don't think that's a fair assumption, and I think that what we would have to address and what has given rise to Mr. Jesus' concern about data quality and data reliability is understanding whether anything more than what has been reported so far in this evidence is of the same quality and can withstand -- and can be reported in a similar manner.

So I think what I would suggest is, we hear what your request is. We can look back and take this away and give this consideration, but we will not make any formal undertaking, but we will take it under advisement and see what and if the data exists and what and if there are concerns with respect to data quality and report back.

MR. JESUS: And one of -- I absolutely agree, and one of the big factors too is the configuration of supply would have evolved over the ten years. So to suggest that the same way it was supplied ten years ago is the same way it is supplied now to that community, you are going to get -- enter that into the picture, and all we will get you is the data that's on that feeder if it exists. I am a little concerned about the data quality and comparing it to what's there today. That's my concern, and it's an honest concern.

MR. FERGUSON: I would never imply otherwise, Mr. Jesus, and I hope you didn't take my questioning to --

MR. JESUS: Oh, no, absolutely not.

MR. FERGUSON: But again, we would rather be able to see it with the caveats than to not see it at all. Mr. Nettleton, if you could undertake to review to see if the data is there and what issues there may be and then providing it can be under advisement.

MR. NETTLETON: Yeah, no, we will take it under advisement and report back.

MR. FERGUSON: Okay.

MR. NETTLETON: So there will be no undertaking, but we will review it and report back.

MR. FERGUSON: Just a few questions on the Anwaatin five-year average as we see here. Thank you for providing the averages across -- I think we can see it's tiny in my printed copy, but definitely better on the screen.

For the Anwaatin five-year averages do I have it correct that is the average of all those feeders that are highlighted in, for instance, B1, B2 -- yeah, B1 and B2? Like, when we say the Anwaatin five-year average, what is the Anwaatin five-year average for each of these figures?

MR. JESUS: That's what it is. You're correct.

MR. FERGUSON: That's what it is?

MR. JESUS: Yes.

MR. FERGUSON: It's the average of the feeders --

MR. JESUS: Correct.
MR. FERGUSON: -- that are seen in these bar charts?
MR. JESUS: Yes.
MR. FERGUSON: Okay. Can I turn you to Figures C1 and C2. Those are on page 6. Would you be able to provide -- I have in my notes ten-year -- five-year average for the 2012 to 2016 urban SAIDI and -- or and rural SAIDI and SAIFI as applicable to each of those? Would you be able to -- because we have -- again, it's very tiny on my printed copy here. We have those bars for urban and rural SAIDI and SAIFI respectively for C1 and C2, but we don't have averages for those, as far as I can see. Would you be able to provide those for each of those charts?
MR. JESUS: Sure.
MR. FERGUSON: Thank you.
MR. SIDLOFSKY: JT3.16.
UNDERTAKING NO. JT3.16: TO PROVIDE AVERAGES FOR URBAN AND RURAL SAIDI AND SAIFI RESPECTIVELY FOR C1 AND C2.
MR. FERGUSON: And you went over, you know, the meaning of "unknown" for these outage causes quite extensively, so I won't question you about that, but I was wondering about the loss of supply category. Is that -- that's exclusively transmission-related losses, and those are the only losses that are in that category that would fall in there.
MR. JESUS: Correct.
MR. FERGUSON: Okay, thank you.
So -- and there's nothing else that falls into that --

that would fall into that category.

MR. JESUS: No, sir.

MR. FERGUSON: Thank you. I just wanted to confirm. That was my understanding of the discussion earlier.

If I can turn you to attachment 3, I just have some kind of very basic understanding questions. It's the list of the assets' age, et cetera.

So in the column marked "feeder" we have a bunch of different categories: F1, 2, 3, 4, M3, M5, and M26, I think are the different categories. And I was wondering what those represented, what those meant?

MS. GARZOUZI: I could describe the table for you.

MR. FERGUSON: Yes, please.

MS. GARZOUZI: So the community is identified. The next column is the distribution station. And so electrically speaking, there may be a transmission station that supplies what we would define as an M-class circuit, which is a feeder that emanates from a transmission facility.

From there we step down power to a distribution station, which steps it down to a lower voltage. Those circuits are now identified as F-class circuits. From each distribution station there could be multiple, and so that's where you'll see F1, F2, F3, you will see M21, M22. That's the designation of the circuit. That's the feeder column, and then you see the average pole age, the pole count, and then the condition. And the last two columns have the projects identified. WPF stands for worst performing feeder, and the in-service date that is tied to the project that is in flight.

MR. FERGUSON: You got almost all of them, all my questions, thank you.

And just to confirm, average pole age, that is in years, not in months?

MS. GARZOUZI: Correct. That is years.

MR. FERGUSON: Thank you.

And I just, I see on the supply station names here there is a designation of either DS or TS, and could you just explain the difference there, please?

MS. GARZOUZI: The transmission station is a facility that's transforming power from the transmission, so 230 kV or 115 kV down to a distribution voltage.

MR. FERGUSON: Sorry, let me just take it a little more basic. TS means transmission station?

MS. GARZOUZI: Yes --

MR. FERGUSON: And DS --

MS. GARZOUZI: -- transmission station, distribution station --

MR. FERGUSON: Thank you.

MS. GARZOUZI: -- that's correct.

MR. FERGUSON: Those are my questions, thank you.

MR. SIDLOFSKY: Thanks, Mr. Ferguson.

Ms. Fraser, are you on the line still?

MS. FRASER: Yes, I am.

MR. SIDLOFSKY: You said you may not have any questions. Is that still the case?

MS. FRASER: I am going to stick with that.

MR. SIDLOFSKY: Okay. The last person on my list would be, sorry, Mr. Stephenson, PWU. You put yourself down for ten minutes. Still on the line?

MR. RUBENSTEIN: He has emailed me to tell me he has no questions for this panel.

MR. SIDLOFSKY: Okay, thank you. That leaves me with -- I believe that's it, except for Mr. Thiessen, who has just a couple of follow-up questions from Staff.

MR. NETTLETON: As I've indicated, we have --

MR. SIDLOFSKY: And we are conscious of Ms. Garzouzi's availability until three o'clock this afternoon.

MR. NETTLETON: It's 12:58 (sic).

MR. SIDLOFSKY: But not by the clock on the wall.

QUESTIONS BY MR. THIESSEN:

MR. THIESSEN: Hello, panel. Two quick questions. The first one involves a number of interrogatories that Staff provided. This would start at tab 38, Staff 189. And there's a number of IRs there where we asked about various activities that you perform, and you did reply with the number of activities per year from two-12 to two-17, and we asked a related question about the cost of each of those things and the trends of cost. But I guess I wasn't specific enough to ask for the actual cost compared to the activity, if you know where I am coming from.

So if I could get an undertaking, where you could look at the different IRs. One is 189, which has to do with trouble calls, 190 is disconnects and disconnects, 191 is defect corrections, 192 is PCB inspections and testing, 194 is brush control, line clearing, and 199 is e-mails and call volumes.

So if you could reply with an undertaking to give me the costs compared to the activity for each year from two-12 to two-17 that would be appreciated.

MS. GARZOUZI: We can undertake to do that. The 2017 number will be a forecast number, and that --

MR. THIESSEN: Fair enough.

MS. GARZOUZI: -- will be then updated once we have our audited financials.

MR. THIESSEN: Thank you.

MR. SIDLOFSKY: That will be JT3.17.

UNDERTAKING NO. JT3.17: TO PROVIDE THE COSTS COMPARED TO THE ACTIVITY FOR EACH YEAR FROM 2012 TO 2017.

MR. THIESSEN: One final question has to do with Staff 195, which is tab 38. And this is a follow-up on the new vegetation management strategy. And in that question, I guess I go through the fact that it's a bit of a radical change going from eight years to three years and the new defect-based approach. And I think what you are saying is that you are going to have a much higher achievement level each year for the same cost. That was in your original budget before you filed Exhibit Q; is that correct?

MS. GARZOUZI: That's correct.

MR. THIESSEN: Okay, so is it fair to say that the previous vegetation management strategy that Hydro One was employing was fairly off-base compared to what you're

proposing in the test years?
MS. GARZOUZI: They are quite different.
MR. THIESSEN: I mean, was Hydro One aware of this defect-based approach being provided in other jurisdictions or other utilities?
MS. GARZOUZI: We did retain a leader in the industry to help provide us with advice on this program. This is a program that we've discussed over the last few days because it is a very costly program and it has high impact on reliability.
And so what we've talked about are really three different approaches to tackling right-of-way management. We have 104,000 kilometres of right-of-way that we need to manage. The old way was more of a traditional approach to right-of-way management. Transmission corridors are maintained that way, some utilities maintain it that way.
What we are proposing in Exhibit Q is really focusing on high-risk defects, and it has been done in one other jurisdiction that I am aware of, and it was a successful implementation. And so with the work that we have done with clear path, which is also filed in Exhibit Q, we describe why we believe that this will help us get on cycle and improve reliability pertaining to vegetation-related outages.
MR. THIESSEN: Thank you. So your new strategy for vegetation management then is not necessarily something that's really widespread in the industry at this point. It's sort of a new approach for other utilities as well?

MS. GARZOUZI: That's correct. I am aware of a few utilities that have similar approaches, but most would do it probably as described previously. So not Exhibit Q, but what was found in the evidence.

MR. THIESSEN: Thank you. I also have a question which stems from Staff IR 144, which is issue 25. And in that response, you provide the costs going forward from 2021 to 2023 -- and there it is up on the screen. And the total costs there are, for that three-year period, 228.4 million.

And I understand from Exhibit Q that the costs that will be incurred for the first three years of the program are 325 million. So you have higher costs at the beginning of the program. You are clearing out some of the backlog that we have heard about. And then as you go into the second three years, your costs are going to drop. Is that correct?

MS. GARZOUZI: That is our hope.

MR. THIESSEN: And that's about $100 million difference over the three years.

MS. GARZOUZI: I think there's a few things here. I am going to point you to Board material; maybe it gives you a better sense of the program trending, the total budget trending for the program. Is that what you are trying to understand, so the costs and how it will decrease over time?

MR. THIESSEN: Yes, where I am going is the costs decreasing over time, I am taking that as a bit of a productivity improvement on behalf of Hydro One. And I am leaning towards one of the responses -- I think it was D in that question -- no, actually, let me go to that specifically.

In response to the first IR that I referenced, which is 38 195, 38 Staff 195, in response D, you talk about that the total vegetation management program is expected to maintain the same budget due to an anticipated increase in spend on public safety and reliability. And I think that's referring to the final three years, where your costs for vegetation management are going down, but there's additional costs in public safety and reliability?

MS. GARZOUZI: That's correct. And then beyond the filed period, we are expecting then the total program to start decreasing.

MR. THIESSEN: Okay. And can you just give me an idea what this additional spending is in public safety and reliability that's different from what's happening in the first three years?

MS. GARZOUZI: Certainly. In the first three years, we are really focussing on high criticality defects and backlog. Trees that are dead, dying and diseased that could fall into our lines or grow into our lines. We are trading that for brush control and other demand activities. That will occur in '18, '19 and '21.

After that, we are expecting the line clearing portion to decrease and the demand activity that -- I was going to call them those low criticality defects, or low and medium risk defects to then increase, and we will tackle those for the next few years.

And then after that, the entire program is expected to decrease by 15 to 20 million.

MR. THIESSEN: So then the last three years that we are talking about will be augmented by these additional activities, leaving the total cost over the first three-year period to the last three-year period to be the same approximately?

MS. GARZOUZI: That's correct.

MR. THIESSEN: Okay. Thank you, those are my questions.

MR. SIDLOFSKY: Thank you, and thanks for the indulgence, Ms. Garzouzi. I appreciate the extra few minutes.

I think that's it for panel 2. Why don't we take our afternoon break, and in 15 minutes we will be back with panel 3.

--- Recess taken at 3:07 p.m.

--- On resuming at 3:27 p.m.

MR. SIDLOFSKY: Good afternoon. We are back and now we are with Hydro One panel 3. Perhaps you could introduce your panel, Mr. Nettleton.

HYDRO ONE NETWORKS INC. - PANEL 3

John Boldt

Henry Andre

Bijan Alagheband

MR. NETTLETON: I can. Thank you, Mr. Sidlofsky.

Seated closest to me is Mr. John Boldt. Mr. Boldt is the manager of asset optimization with Hydro One. Beside Mr. Boldt is Mr. Henry Andre. Mr. Andre is director of pricing at Hydro One. And beside Mr. Andre is Mr. Bijan Alagheband, and I apologize if I mispronounced Mr. Alagheband's name. He is manager of economics and load forecasts with Hydro One.

MR. SIDLOFSKY: Thank you. Just before we begin -- and we are going to begin with Schools. Just before we do begin, though, I am advised by Mr. Harper for VECC that he is going to be submitting his questions in writing, as opposed to asking them orally. I don't have those questions at this point, but I would ask for an undertaking from Hydro One to respond to those questions when they are submitted.

MR. NETTLETON: We will take that undertaking.

MR. SIDLOFSKY: Thank you. That will be JT3.18.

UNDERTAKING NO. JT3.18: TO RESPOND TO MR. HARPER'S WRITTEN QUESTIONS FOR HONI PANEL 3.

MR. SIDLOFSKY: Similarly, Ms. Girvan for CCC will be submitting her questions in writing. I would ask for a similar undertaking on those.

MR. NETTLETON: We will provide that undertaking.

MR. SIDLOFSKY: JT3.19, thank you.

UNDERTAKING NO. JT3.19: TO RESPOND TO MS. GIRVAN'S WRITTEN QUESTIONS FOR HONI PANEL 3.

MR. SIDLOFSKY: And Mr. Shepherd.

QUESTIONS BY MR. SHEPHERD:

MR. SHEPHERD: Thank you.

Hi. I am the lawyer for -- one of the lawyers for Schools. I want to start with VECC number 126. It's issue -- it's tab 52.

MR. ANDRE: Yes.

MR. SHEPHERD: So you were asked to provide the equivalent of Appendix 1 for the three acquired utilities, and Appendix 1 in that exhibit is the standard form of loss factor calculation. It's actually Appendix 2R in the application.

And you said, well, we don't have the information, and I looked at it and I thought, what information don't you have?

MR. ALAGHEBAND: It is the information at the purchase level. We have the sales figures but not at the purchase. So there is -- if you look at that appendix you see that there is a line showing how much it was purchased, and then how much it was purchased from -- and distinguishing between IESO and purchase on behalf of large users.

So we don't have that total purchase in this case. And sales figures we have, so if we had the purchase we could just deduct and calculate the loss no problem, but we don't have the purchase, because we are not running those companies in the older days, so we didn't keep track of their purchase.

MR. SHEPHERD: This is reported --

MR. ALAGHEBAND: Purchase means simply you buy something from IESO and you may buy something from embedded generators in your area or in -- under in the city, and then you try to distribute what you purchased to the customers, so the difference -- the loss is simply difference between the purchase and the loss -- and the sales.

So if you don't have the purchase, we cannot calculate the loss, very simple.

MR. SHEPHERD: So help me understand this. You have owned these companies for several years now. You don't know how much their wholesale kilowatt-hours were?

MR. ALAGHEBAND: What we have for two of the companies, Haldimand and Woodstock, they were integrated into Hydro One in September 2016, so we don't have numbers prior to that year. And for Norfolk it was in 2015. So we have -- and the idea is that, you know, that you wanted to have a five-year, you look at the table that they needed to provide, and this was for the five-year period. We don't have the five-year period numbers.

MR. SHEPHERD: And why don't you have the records of the companies you bought for the period before you bought them?

MR. ALAGHEBAND: We didn't need that, for example, when we wanted to purchase the companies we look at their sales figures, and that was good enough for us.

MR. SHEPHERD: That's actually not what the agreement says, sir. What the agreements in each case say is that you get all their records --

MR. ALAGHEBAND: Yes, we get all their records --

MR. SHEPHERD: -- so at this point --

MR. ALAGHEBAND: -- yes, we get all their records, and we are going to follow up on that one, but because the integration into Hydro One system, integration of that information into Hydro One's system was performed recently, as I mentioned, you know, for Woodstock and Haldimand it was not September 2016, so we have a first few months of data for there.

MR. ANDRE: So Mr. Shepherd, we have -- certainly we have sales records, as Mr. Alagheband said, but information on the purchases wasn't part of the information that -- certainly that we didn't have ready access to. I don't know if it was transferred or not, but it's not part of the information data set that came to our group, so --

MR. SHEPHERD: So you don't know what the purchases were of those three compares prior to when you acquired them or when you integrated them?

MR. ALAGHEBAND: When we acquired them, we had all the sales -- it was really corset (sic) for all the sales figures that they are relevant.

MR. ANDRE: "Required".

MR. ALAGHEBAND: You know, but that was it. We don't have purchase --

MR. SHEPHERD: I am asking about the wholesale kilowatt-hours.

MR. ALAGHEBAND: Yes.

MR. ANDRE: Right. Yes. The -- from -- I assume it's from the time of integration, I would think, subject to check.

MR. SHEPHERD: So that's later than the purchase.

MR. ALAGHEBAND: After integration, we are supposed to gather that data and somehow record it somewhere. And that process itself is not completed yet, but we have some preliminary numbers from September 2016, which means only a few -- in accordance with the table, if you want to duplicate that table, for example, for Woodstock and, you know, Haldimand, we would have only a few months of data, which is not even one full year of data.

MR. SHEPHERD: All right. I will follow up on this in the hearing, thank you.

My next question is on Exhibit I, tab 56, SEC 90. Now, in this interrogatory we actually attached a table of savings from the consolidation of these three utilities from your argument in EB-2016-0276. Now, you haven't attached that to the interrogatory response, but you have attached a revision to that; right?

MR. ANDRE: Yes, that's correct.

MR. SHEPHERD: And what the revision says is that now you have an even lower estimate of your savings from the one you had on May 5th, 2017; right?

MR. ANDRE: I don't have the information on May 5th. I do see that this currently says that the savings are -- in 2021, for example, the savings are 9 million, so I can only confirm this one. I don't have the previous version that you referred to.

MR. SHEPHERD: Why don't you have? It was in the question. The question said "here's what you said".

MR. ANDRE: Yeah, so, again, this is the -- so we updated the table and, yeah, these are the savings that we are now saying. If you are saying that they are different than what was in the question, I think, yeah, they are different, but these are the latest savings based on the latest information that we are saying, so I am not sure what your question is.

MR. SHEPHERD: So now -- so the savings are lower now than they were last May; right?

MR. ANDRE: Being on the rates side, I looked at the numbers in 21 and 22, and those numbers appeared to show the same OM&A savings and then slightly smaller capital savings, yes.

MR. SHEPHERD: About two-thirds of the capital savings; right?

MR. ANDRE: Yup, that's the response.

MR. SHEPHERD: All right. And you don't know why this is? You don't know why the savings are lower?

MR. ANDRE: I know that the capital -- the capital spend has changed. So the capital spend on the three acquired utilities now reflects the latest information provided by the panel that was just up here, and this, now, reflects the -- with that updated capital spending it updates the savings.

MR. SHEPHERD: Do you know what Hydro One originally claimed it was going to save in these three utilities when it applied for its approval from the Board?

MR. ANDRE: No, I do not. I wasn't in the MAADs application.

MR. SHEPHERD: So will you accept subject to check that you claimed that you are going to save 107.1 million and you currently are saying you're going to save 91.4 million?

MR. NETTLETON: Mr. Shepherd, what is the purpose of this question in terms of clarification? What are you seeking a clarification from? It sounds like you are cross-examining and pointing out inconsistencies between what was said in 2016 and in the current interrogatory response.

MR. SHEPHERD: We asked you to look at a schedule of savings that you provided in another case. Instead, you said no, these are not the savings anymore. We have changed them again and here's the new ones.

And I am saying okay, how come you keep changing them and I want to understand. Is that not a proper follow-up?

MR. NETTLETON: It's a different question, Mr. Shepherd.

MR. SHEPHERD: Well, how could I know that they were going change them again when I asked the question?

MR. NETTLETON: You just had Mr. Andre explain that, yes, these are the updated savings numbers. You have the most current forecasted numbers.

MR. SHEPHERD: Okay. So I am going to ask you to undertake to explain why the -- to identify the changes in your claimed savings between your original applications and now and why.

MR. ANDRE: So your question is why did our capital spend get updated?

MR. SHEPHERD: No, I just asked about your original applications. In your original applications, you claimed to save $107 million. Now you are saying no, it's only going to be 91, and I'd like to know what the changes are and why.

MR. ANDRE: I mean, the answer, Mr. Shepherd, is that the capital spend and the OM&A spend now reflect the latest information available at the time that we filed this application, and that latest information on the OM&A and capital spend, yes, it's different than what was originally submitted and it results in that difference.

So if I give you an undertaking response, that's all it's going to say is that we have provided new spend levels based on latest information and yes, that results in a different number.

MR. SHEPHERD: And you are not going to tell us what the changes are? I am asking you to tell us what the changes are.

MR. NETTLETON: The changes, as I understand it, Mr. Shepherd, are due to additional new information as compared to what the original forecast was when the MAAD application was filed in the 2016-0276 proceeding.

MR. SHEPHERD: No, the MAAD application was not filed in 0726. I am asking about the original forecast of savings in the three MAAD applications for Norfolk, Haldimand, and Woodstock.

MR. NETTLETON: I must be getting my proceedings wrong. But in any event, you are asking a question about what has changed from the original forecast in the MAAD applications to today.

And today and I am saying that whatever happened in the past is not relevant with respect to this proceeding. We have provided you with the updated forecast information, and so I am instructing the witness not to answer the question.

MR. SHEPHERD: So you don't believe that the Board will think it's relevant that you didn't deliver the savings you said you were going to deliver, and you keep reducing them. Every time we ask you a question, you reduce them again.

MR. NETTLETON: If you are asking what the changes -- Mr. Andre, I don't know if you can answer this. But can you give any information to explain what has caused the change in forecast, or is that something for --

MR. ANDRE: Well, I mean I am surprised because panel 2, that developed the latest spend levels, was just up here and I am sure could have probably answered what are the programs that make up that capital spend that's there now. I certainly can't.

I mean that's why I said is what you are looking for a detail of what the new capital spend is and why the new capital spend that we are forecasting now is different than what was forecast four, five years ago.

MR. SHEPHERD: I am asking why your savings are lower than they were when you got approval. I am asking you to undertake to provide details of what changes caused them to be lower; can you do that?

MR. ANDRE: Yes, sure, we will undertake to do that.

MR. SIDLOFSKY: JT3.20.

UNDERTAKING NO. JT3.20: TO PROVIDE DETAILS OF THE CHANGES THAT CAUSED SAVINGS TO BE LOWER THAN WHEN HONI GOT APPROVAL

MR. SHEPHERD: My next question is on the same interrogatory response; this is page 3 of that response in F. So we were looking at the rate base allocated to the six acquired rate classes, and it looks like it totalled 361.5 million. And you said yes, it does, but that's not the right number.

So maybe you could just explain this answer and why the number that appears to be in the cost allocation model is not the right number for rate-making purposes.

MR. ANDRE: Right. So the $361.5 million figure comes from the 01 sheet of the cost allocation model. And what that represents is the amount of assets that would have been or were allocated to those classes prior to the application of the adjustment factors that Hydro One has adopted.

The adjustment factors, in terms of being able to incorporate it into the model, Mr. Shepherd, the easiest place to do that was in the allocaters tab. So it's in that tab where we make the adjustments -- I guess it's E 6 allocators tab. It's in that tab where we show the adjustments to the gross fixed assets after the application of the adjustment factors. And that doesn't translate into the numbers that come into the 01 sheet. It goes and gets these numbers from another tab where that adjustment wasn't reflected.

So in terms of the costs that are allocated by rate base, like net income, interest costs, PILs and all of that, that allocation is based on the 173.6 million in rate base, not the 361.

MR. SHEPHERD: Excellent, thank you. And my next question is still in the same interrogatory response. This is in attachment 1, and I have two questions on that.

The first is -- we heard the other day that you have zero capital productivity -- Hydro One has zero measured capital productivity. Did you hear that.

MR. ANDRE: No. To be honest, Mr. Shepherd, I haven't heard that testimony.

MR. SHEPHERD: Will you accept, subject to check, that your witness said that?

MR. ANDRE: Okay.

MR. SHEPHERD: I am looking at these lower capital spend for the acquired area and I am thinking, well, if this is not because of productivity, then doesn't this mean you're investing less in their systems?

And I -- there's probably a good explanation; I am just trying to understand.

MR. ANDRE: Well, like I say, you know, if that question had been put to panel 2 -- I expect that yes, if they are spending less, Mr. Shepherd, we now had the utility's integrated for, you know, a year, a year plus, and I would imagine they have better information on the status and the performance and the state of those assets.

So I would expect that the capital reflects the latest information they have about the need of the assets in the acquired utilities.

MR. SHEPHERD: I was asking more a question, and this is presumably not you -- I am sorry, the information said all the acquired questions were of this panel, so that's why I am asking you.

MR. ANDRE: Sure, no problem, Mr. Shepherd.

MR. SHEPHERD: Otherwise I would have asked the last panel.

What I am trying to understand is whether this means that the emphasis or the prioritization of the customers in the acquired areas has been reduced if you are spending less. Or is that not a fair conclusion?

And if that's outside of your area, just tell me.

MR. ANDRE: No, like I said, this reflects what our asset management group now believes the assets in these three acquired utilities require to maintain a safe reliable system.

But, yes, it does -- it does represent a change, but this is the latest information on what we believe these assets require.

MR. SHEPHERD: All right. The next question I have is on Exhibit I, tab 56, SEC 91. And we asked for a list of all acquisition costs associated with the three acquired utilities, and you referred us to BOMA 87. But BOMA 87 is simply a refusal.

So I take it that I should read this response as a refusal to answer. Is that right?

MR. ANDRE: I don't know if Mr. Nettleton -- like I did not -- this is not one of the ones that I responded to. And so I am not familiar with the acquisition costs associated with the three acquired utilities as far as, you know, the fact that it references one where we say we don't have information. I have nothing to add there.

MR. SHEPHERD: It doesn't say we don't have information. It says we are not going to tell you.

Mr. Nettleton, can you confirm that this is intended to be a refusal?

MR. NETTLETON: Yes, I am confirming that the response to BOMA 87, part B, says that acquisition costs are not included in any revenue requirement and therefore are not relevant to this application. And for that reason, they are not being provided.

MR. SHEPHERD: Okay. And so then in answer to my question, SEC 91 is a refusal?

MR. NETTLETON: Correct.

MR. SHEPHERD: Thank you.

My next question, which I think is you, Mr. Andre, is I56-SEC-94. And this gives a breakdown of the costs associated with the combined classes that have been -- the combined classes are the ones in which the acquired customers didn't go into a special class, they went into one of your general classes; is that right?

MR. ANDRE: Yeah, correct, I agree.

MR. SHEPHERD: Okay. Have these numbers changed from the May "cam" to the -- was it May or March?

MR. ANDRE: There was a -- March was our original, and then June -- June 7th was our update.

MR. SHEPHERD: But you made a bunch of changes in December as well.

MR. ANDRE: Yes, so March, our original, June was what we call the blue-page update, affectionately referred to as such, and then the December Q exhibit update.

MR. SHEPHERD: So are these costs materially different from the ones in March?

MR. ANDRE: No, they wouldn't be, because these are allocated per the Board's -- the principles underlying the Board's cost allocation model, so these would have been affected to the extent that, you know, the normal inputs to the cost allocation model like revenue requirement -- I know there was some changes to revenue requirement from March until June, so that would have impacted it slightly, but they certainly wouldn't have been impacted by any cost allocation or changes to the approach for allocating costs to the acquireds. That wouldn't have impacted these costs at all. These are solely driven by the Board's cost allocation model principles.

MR. SHEPHERD: So the only classes that were affected by actual cost allocation decisions were the acquired classes?

MR. ANDRE: Correct.

MR. SHEPHERD: And by reference, all the other classes were impacted by that reallocation, but --

MR. ANDRE: True.

MR. SHEPHERD: -- the impacts on the others were so small that they are not material.

MR. ANDRE: Yes, Mr. Shepherd; that's correct.

MR. SHEPHERD: Okay. Then the next -- my next question is I-56, SEC 95. And I have two questions about this. First, we asked you in A for information on discussions about reducing the number of classes. And in particular, we are concerned with the acquired classes, obviously, because they have special rates, right? And you said, no, we didn't have any discussions. But then you went on to say, please see I56-SEC-97, and SEC 97 is actually a refusal.

So I am wondering, are you refusing to answer this or is there simply no information available?

MR. ANDRE: Let me just see. Part D.

MR. SHEPHERD: D.

MR. ANDRE: Yeah, no, the one that we pointed to.

Yes, so 97D, the refusal is with respect to, you know, all e-mails, reports, and other documentation, sort of the day-to-day discussions that happen within our work group.

So let me go back here... So I guess it's saying the same things. First off, the first part of the response is as it is, Mr. Shepherd, there are no plans and there have been no discussions about reducing the number of classes. These six classes have been created. We hope to use them in the future potentially to merge others as there's another response that says they may go into that, we may need to create new classes, so that part of it is as it is.

The reference to part D was simply, you know -- yeah, I am not sure why we even referred you to part D, because I think that first sentence gives you the full response, doesn't it?

MR. SHEPHERD: All right. You could read it as, well, we didn't look because we didn't have to. Or you could read it as, we know there were no discussions, but even if there were we wouldn't give them to you.

MR. ANDRE: Yes. So I can confirm that for this response it's the former.

MR. SHEPHERD: Okay, thanks.

And then the second question on that response is that you have said, and you have said this in other places too, in other proceedings too, that -- and indeed, other utilities have said this about harmonization, that you are going to keep these six classes separate until there's no material difference in the costs to serve those classes. And I am trying to understand, if they are integrated into your system, how is the cost to serve ever going to converge? Can you just explain how that happens?

MR. ANDRE: The -- I understand -- I understand the point that you are making, and I would agree that, you know, given the use of the adjustment factors they will always get less of a share than -- of certain costs than other classes.

So the convergence is not likely. But I guess, I mean, you know, the Board could make decisions about -- about, you know, for example, the move to all fixed rates.

If it turns out that the all fixed residential rate for one of these new acquired classes, you know, is within a dollar or $2 of one of our other classes, is there a need to maintain two separate classes.

So it's really more of a, we don't know what policy changes may come and what they might do to the classes, so it's a catch-all to say it could happen, but I agree that I wouldn't see that happening in the foreseeable future, and I can't see what would drive -- I can't give you an example of something that would drive us to end up with the same rates.

MR. SHEPHERD: There's not a natural thing that happens that converges costs; right? This would have to be something unusual for the costs to converge?

MR. ANDRE: The only thing I can think of, I mean, you know, if all of the assets -- in 40 years, when all of the assets -- when there's been a turnover, complete turnover, of the assets that are associated with serving these acquired utilities, presumably all of these brand-new assets would have been put in at the Hydro One cost, as opposed to the cost that the acquired utilities spent in putting in those assets.

So, you know, perhaps 30 or 40 years from now there could be a convergence.

MR. SHEPHERD: Oh, I see, I see, I see, okay. That's good. I understand, thank you.

Then my next question is on Exhibit I, tab 56, SEC 96. And I just want to -- I am looking at C, all right? I am looking at the response to C in this. And in each of these components of C and D, you're breaking down the -- the costs that specifically relate to Woodstock, for example, or Haldimand and Norfolk, and the allocated costs and trying to explain the difference. And maybe you can start by explaining that concept.

MR. ANDRE: Sure. Because you are right, Mr. Shepherd. All of the questions follow more or less that same approach to the response. So let's look at the first sentence.

So the 2.2 million -- and I don't know if it's something that's sort of been picked up, but that represents the incremental cost, so the additional costs in OM&A that Hydro One has to spend in order to serve Woodstock, and so it represents the additional OM&A that was added to Hydro One's revenue requirement in 2021. But just the incremental costs.

The 4.3 million that's allocated by the cost allocation model would represent the allocated share of Hydro One's total distribution OM&A costs, total customer service OM&A costs, total A&G OM&A costs.

So once those new classes are created in the model, we follow the Board's, you know, model allocation principles to allocate a share of the Hydro One total into each of those acquired classes.

So that's what you see there. You see the difference -- I mean, I can't guarantee you that it's actually 2.2 million in costs that are actually -- in distribution OM&A costs that are actually allocated, because the allocation goes back to Hydro One's total costs and allocates a share of those total costs.

MR. SHEPHERD: So when you earlier -- these numbers -- sorry, the 2.2 and the 4.3, they are for 2021; right?

MR. ANDRE: That's correct.

MR. SHEPHERD: So where you -- and this is Woodstock. So in 2021, where you estimate the savings from -- and this is back in SEC 90 -- the savings from the acquisition, you're comparing the incremental costs to the status quo estimate; right?

MR. ANDRE: Yes, that's correct, because they represent the additional costs that get added to Hydro One's total revenue requirement. So, you know, the savings are measured relative to what gets added to Hydro One's total budget to serve the acquireds.

MR. SHEPHERD: I understand, I understand. So from the point of view of the customers, the important number is not the 2.2 million obviously, because that's not what they are paying. They are paying the 4.3, right?

MR. ANDRE: That's the cost allocated to them. The rates actually depends on the revenue to cost ratio that's applied to the acquired classes. But, yes, these are the costs that are allocated to that class, although none of the -- the rates don't actually reflect this full cost that's allocated to them.

MR. SHEPHERD: Understood, because they have a revenue cost ratio of less than one.

MR. ANDRE: Less than one, correct.

MR. SHEPHERD: But the point here is that it's actually costing Hydro $4.3 million to serve those customers in Woodstock, right? Otherwise, you wouldn't allocate those costs to them.

MR. ANDRE: For the purpose of setting rates, we have to run a cost allocation model and we have to divvy up the costs that Hydro One needs to run its business among all of the rate classes that it serves.

So I would say this represents the allocated cost to serve those acquired classes, yes.

MR. SHEPHERD: So if their forecast -- I am just taking Woodstock for example. Their status quo forecast was 4.4 million, and you are now allocating 4.3 million to them. That's not much of a savings. That's sort of a rounding error, right?

MR. ANDRE: The savings are to Hydro One as a whole. The savings represent the difference between how much more Hydro One needs to spend in order to be able to serve those acquired utilities. It doesn't represent the allocated cost to them. Yes, I would agree with that.

MR. SHEPHERD: See, I am looking at this and I am thinking, well, whatever the savings were, none of them are going to these acquired customers. These acquired customers -- they are all going to your other customers, not acquired customers.

Subject to your cost revenue adjustment, I get that. But subject to that, basically the savings are going to your legacy customers, not your acquired customers. Is that fair?

MR. ANDRE: No, I don't think -- I think the acquired customers share in the savings that accrue to Hydro One in total. So I think they do get a share of the savings. And certainly when you compare the costs that we are allocating to them in 2021 and you compare that to the OM&A costs that those acquired utilities were paying when they ran their last cost allocation model, which in some cases was more than ten years ago, if you compare those OM&A costs, I would say there's definitely some savings.

But Hydro One has always been very clear that the savings it has identified for the Board relate to the savings to Hydro One has a whole.

MR. SHEPHERD: Okay, thank you. And so then my last question on this particular interrogatory, SEC 96, is on page 5. And what it says is that the total -- this is in E, little 3. It says although you have allocated $41.2 million to the acquired utility customers, you are only charging them 34.9 million in rates. Do you see that?

MR. ANDRE: Yes, I do.

MR. SHEPHERD: And then this is what you were talking about, right, the revenue requirement?

MR. ANDRE: Yes, that's exactly right. That is exactly what I was referring to.

MR. SHEPHERD: Is it fair to then treat this as a subsidy of those customers by the rest of your customers? Is that right?

MR. ANDRE: I don't know if I would use the word subsidy. I mean, the Board in their decisions on the MAAD said, you know, when it comes time to set rates for the acquired customers, find some way to set rates that reflect the cost to serve them.

So I think the cost to serve them is 41.2. The Board has a range of acceptable revenue to cost ratios that it considers acceptable, you know, from .85 to 1.15.

This falls within that range, so to the extent that anybody that doesn't have or any class that doesn't have the revenue to cost ratio at the exact value of one is getting a subsidy, then I guess you could characterize this as a subsidy. But I would just characterize it as falling with the Board's approved revenue to rate ratio range for all classes.

MR. SHEPHERD: My next question is on I56-SEC-97, and I am looking at page, in the second bullet point where you talk about your changes to the GFA and NFA adjustment factors and you say that you -- what you were doing is expanding the assets to be treated as local assets and correcting in-service addition amounts.

So I wonder if you could just expand on that and explain how that works and what the impacts are.

MR. ANDRE: Right. So in the March filing, we were allowing the Board's cost allocation model to identify how many station costs -- how much of station costs associated with US of A accounts 1815 and 1820, how much should flow to the new acquired classes. So that our original model both in March and in June.

But then upon further consideration, I mean, the distribution stations really are geared to serving the local customers, not unlike the poles and wires and transformers. So we took the view that distribution stations really should be -- we shouldn't be allowing the model to allocate it. Let's allow the model to allocate it, but then adjust it down to what these acquired utilities were actually spending on accounts 1815 and 1820.

MR. SHEPHERD: So are you doing that in other towns that have their own distribution stations around the province?

MR. ANDRE: No. The rest of our -- the rest of our system share the costs of stations, they share the costs of -- I mean, they 100 percent share in the costs of serving Northern Ontario. They don't pay the cost of serving Northern Ontario. They pay a blended cost that reflects serving southern Ontario, eastern Ontario, and northern Ontario.

But what's different here, Mr. Shepherd, as you well know, the Board has indicated that they would like us to make efforts to charge these acquired utilities what it costs us to serve them. So we felt that making this adjustment aligned with what the Board asked us to do as part of that MAAD decision.

MR. SHEPHERD: So then you are treating Woodstock, for example -- from a cost allocation point of view, you are treating Woodstock quite different than Smith Falls, let's say, which is another one you acquired a long time ago, and presumably would have some local station assets -- in fact probably several, like Woodstock. But whereas for Smith's Falls, you would say you share in all the station asset costs around the province. For Woodstock, you say you pay all of the costs of the station assets that you have, generally.

MR. ANDRE: Yes, and the integration of Smith Falls and the other 80-plus acquired utilities happened in 2006, and the approach to integrating them at that point in time was reviewed with the Board, put in front of the Board, put in front of intervenors and the decision was made to integrate them in the way that it was done, which was to merge them into Hydro One else acquired classes.

The direction from the Board with respect to these three utilities was different and we're -- you know, we've tailored our application to suit what the Board has directed us to do.

MR. SHEPHERD: Have you had any discussions internally as to whether you should apply the same concept to the other towns in the province that you are serving? I mean, there's quite a lot of them that have relatively unique costs, right?

MR. ANDRE: That's the -- you know, there is a limit to how many rate classes. You mentioned Smith Falls, but those were acquired utilities. What about towns that were Always -- have always been part of Hydro One. Should we be creating separate rate classes for them as well?

I think the principle that Hydro One, given its diverse service territory and a recognition of the fact that it can cost -- the cost can be considerably different depending on where you are in the province, I think this notion of blending and providing a postage stamp rate is the most appropriate for a utility like Hydro One. It minimizes the impacts on -- it spreads the increased cost among -- of serving rural and remote areas among all customers.

So no, there's no plans to develop special rates for other communities.

MR. SHEPHERD: So there's a -- I will leave that. Now, the second part of this is you said you corrected some of the in-service addition amounts.

MR. ANDRE: Yes. So that was -- if you go to and perhaps I can take you there. The details of the adjustment factors, developing that, the spreadsheet that details that was provided as an attachment to interrogatory I49-Staff-242, and what you see there is we start with -- I don't know if you want -- might as well take me there.

MR. SHEPHERD: I did look at it and I didn't understand it.

MR. ANDRE: Oh, okay. Staff 242. It might have been provided as a spreadsheet. Okay. So I don't know if you would have that. But I can walk you through it.

The first very tab on that essentially shows how we got to the gross book value of -- for each of the acquireds in '21 and '22. Well, in this case '21, because that's the cost allocation year. And it starts back in '15, and it says what was the gross book value at the end of '14, how many in-service additions were made in '15, and that gets you to the end of '15. And then how many in-service additions were made in '16, and so on, and it builds that up, and there was just a transposition error, there was some data that was shown for one of the years that actually should have been shown in another year, and we caught that error and then fixed it.

But -- so it was really -- and it was in those early years. I think some of the in-service additions for '16 were shown -- were incorrectly shown.

MR. SHEPHERD: Okay. So in these two adjustments that you made to the GFA and NFA adjustment factors, the change to treat more things as local assets, more stations as local assets, that was the big impact, right? The --

MR. ANDRE: Yes.

MR. SHEPHERD: -- in-service additions wasn't a big deal.

MR. ANDRE: No, exactly. You are exactly right. It wasn't a big deal. And -- yeah. So if you go to that bullet on the top of page 3.

MR. SHEPHERD: Yes.

MR. WILKIE: You can see there for 1815 and 1820 you see those first two rows and I think -- so between the two of them in December we were allocating 17 million to the acquired utilities. If my memory serves me, when we were letting the model allocate, it was something like 40 million in station costs that were being allocated. So, yes, that adjustment is what resulted in the biggest change.

MR. SHEPHERD: You see, this looks like you're actually allocating more in December than in March.

MR. ANDRE: Yes, so there wasn't a title on that table, Mr. Shepherd. The title of that table should say "GFA subject to adjustment". So this is the amount that would be subject to the adjustment. So now we have -- okay, hold on.

Yes, so in other words, what we do is the model would have allocated, as I say, if I recollect, like somewhere around 40 million. And now, before we would have let the 40 million sit there as being allocated to the acquired classes. Now we bring that 40 million down to 9 plus 8, we bring it down to the value that -- the adjusted value that we know is actually required to serve the utilities.

MR. SHEPHERD: So these are the amounts allocated to the acquireds, or are these the amounts to which you apply them in adjustment --

MR. ANDRE: These are the amounts that we -- that are applied to the acquireds. So in other words, we take whatever the model allocates and we bring it down to these values shown here, so that in the end this gets allocated to the acquireds.

MR. SHEPHERD: Well, then I should read the left-hand column as being 250 million, not 210 million, because there was actually another 40 million allocated to them; right?

MR. ANDRE: No, so the March filing represents the numbers. Back then we were only adjusting what the model did. So we were only adjusting 1830, for example, whatever the model was allocating, we were bringing that down to 64 million. If the model wanted to allocate 70 or 80 we were bringing it down to 64, for 1835 we took whatever the model was allocating and we are bringing it down to 44.

Now, in December, we are bringing -- so what you see there, the minus 3.6, that represents the change in the in-service corrections that were referred to. So now instead of bringing it down to 64 we are bringing it down, 1830, account 1830, instead of bringing it down to 64.7 we are bringing it down to 62.4. But this represents the amount of assets that are actually required to serve the acquired utilities, and so we adjust the results from the cost allocation model to align with these numbers.

MR. SHEPHERD: Okay. So I still don't understand. You did allocate amounts relevant to 1815 and 1820 to the acquireds in March.

MR. ANDRE: Right.

MR. SHEPHERD: There's nothing here for that.

MR. ANDRE: That's right. So what that shows is in

March we were not adjusting. Whatever the model allocated per the Board's principles to 1815 and 1820, we let that sit.

MR. SHEPHERD: So there were amounts allocated.

MR. ANDRE: Oh absolutely.

MR. SHEPHERD: They are just not included on this list.

MR. ANDRE: Because they weren't brought down -- we let the model allocate it and we left it as allocated by the model, whereas for the other accounts we didn't leave those accounts as allocated by the model, we brought it down to the values that are shown in that table.

MR. SHEPHERD: Do we have in the evidence somewhere a breakdown of this adjusted allocation where all of it fits together so we can see, you know, this 40 million that was in in March, where it was and how it disappeared and became 17, that sort of thing?

MR. ANDRE: What you have in the previous reference that I gave you is the adjustments that exist now, in December, as we are now currently proposing and asking the Board to approve. The adjustment worksheet that existed for March, no, that's not in evidence, it's -- it's not in evidence.

MR. SHEPHERD: Can you -- as you can see, I am trying really hard to understand these numbers and I am not. Can you -- can you undertake to provide an explanation that shows for 1815 and 1820, at least -- I mean, for all of them if you can, but at least -- all of these US of As if you can, but at least for 1850 and 1820, what you allocated in March and how and what you allocated in June and how? Just with an explanation.

MR. ANDRE: Sure.

MR. SHEPHERD: This is what we changed, and we -- to achieve this result, here's the impact, it looks like an impact of $23 million or so, whatever, and this is what it means in terms of rates.

MR. ANDRE: Sure, yeah, we can do that, and then you will have -- I have been seeing 40 million, but then you will have the actual number. It will show you what the model allocated, and we made no adjustment, and then in December you will see the adjust, so, yes, I will take that undertaking, no problem.

MR. SIDLOFSKY: JT3.21.

UNDERTAKING NO. JT3.21: TO PROVIDE AN EXPLANATION THAT SHOWS FOR 1815 AND 1820, OR FOR ALL OF THEM, WHAT WAS ALLOCATED IN MARCH AND HOW AND WHAT WAS ALLOCATED IN JUNE AND HOW.

MR. SHEPHERD: Now, we asked in -- still in the same interrogatory response, I56-SEC-97 -- and we are still in that same one. In D, we asked you for memos and analyses between March and December on why you made this change, why you made these changes to the allocations, and you said, no, no, no, that's too much work.

And let me explain what we are trying to get at. It appears on the surface like under attack in Orillia you said, oh, we'd better -- we'd better somehow reduce these costs that we are allocating to the ones we have already acquired because this is hurting us in this other case. And that suggests that your change in the allocations is a regulatory change, not an empirical change. It's tactical for another purpose. And I am not alleging that's true, but you can see where you'd look at this and you'd say, ah, that must be what they're doing. So I am trying to get at your underlying documents to see why you did it so that you can defend against that.

MR. ANDRE: Right. So you pointed me to D, but what you're actually referring to, it's part E that asks:

> "Please provide all memos, presentations, e-mails, reports that refer to any relationship or potential relationship between changes to cost allocation and the EB case, which the Orillia case."

And to that one I think the answer is very clear: No such documentation exists. And there were -- I am the director of the rates group. I can assure you there was no discussion about making changes to allocation because of what was going on in Orillia.

MR. SHEPHERD: The reason we asked it in two steps is because we expected that you would -- that if you were responding tactically, then you wouldn't say, well, let's write a memo saying we have to reduce these costs because otherwise we are going to lose this case. Nobody in their right mind does that.

But what you might say is we have to relook at our allocation of costs to the acquired classes because it's going to hurt us in the long term in our acquisition strategy. And that's what I am looking for in D.

MR. ANDRE: Right.

MR. SHEPHERD: If you just tell me there is no such discussion, I'm great.

MR. ANDRE: Yes, there was no such discussion.

MR. SHEPHERD: Awesome, thank you. Then my next question is in I56-SEC-98, and I want to ask just a couple of general questions about the loss factors that you have talked about here.

You are increasing the loss factors for all three acquired service territories, right?

MR. ANDRE: The Norfolk -- the Haldimand is what I would characterize an as a very marginal increase, but yes.

MR. SHEPHERD: And the reason is because you are taking one component of the loss factor, which is the bulk component, is that right?

MR. ANDRE: Yes, that's right.

MR. SHEPHERD: And you are replacing their old one with your actual bulk loss factor.

MR. ANDRE: Yes, that's correct, Mr. Shepherd. That's what's driving it, yes.

MR. SHEPHERD: And yours is generally higher than theirs were.

MR. ANDRE: Right. Ours is 3.4 and in Woodstock's case, you can see here we estimate it to be around 2. And with Norfolk and Haldimand, we estimate it to be around

2.85. So, yes, changing that to 3.4 is what's driving the change in the loss factor.

MR. SHEPHERD: Now, the effect of increasing the loss factor is not just that a customer pays more distribution charges, but they also pay -- effectively, they pay more on transmission and the commodity, right, because they pay for more kilowatt-hours than they actually had delivered to them.

MR. ANDRE: Yes, it's -- in fact, it's on transmission and commodity where this has an impact. Distribution charges, most of them are actually applied on non-loss adjusted, so yes.

MR. SHEPHERD: Okay. And so the differences can be reasonably large, and I just wanted to ask you about a couple of them.

So for Woodstock, for example, my estimate is that that increases the non-distribution component of the bill by about 1.3 percent. Is that reasonable? Am I in the ballpark there?

MR. ANDRE: Well, in same response, Mr. Shepherd, there was attachment 1 provided. And certainly, I think, for Woodstock, I see numbers for the residential general service less than 50, and general service more than 50 -- you know, .91 percent, .3. So those are the numbers that we have worked out in terms of the impact --

MR. SHEPHERD: And that's in total bills, so the commodity and transmission component of 1.3 is probably about right.

Tell me whether my math is right. If I just is divide 1.057 by 1.0431, I get the impact, right?

MR. ANDRE: You get which?

MR. SHEPHERD: I get the impact on the --

MR. ANDRE: Yes, you are right. Yes, that percentage change is how much the commodity would change, yes.

MR. SHEPHERD: All right. So then I want to go to Exhibit I56-SEC -- let's use 99, and I am going to the spreadsheet which is 02, okay?

MR. ANDRE: Okay. I think these were provided as spreadsheets, so you night not necessarily have it. It depends on the question Mr. Shepherd has. Should Erin pull that up?

MR. SHEPHERD: Yes, yes, 99-02. You will be happy to know that I am rapidly reaching the end.

And when it comes up, I am looking at the GS 50 to 99 tab.

MS. McKINNON: Nothing seems to be working on my computer at the moment, so I will bring it up momentarily.

MR. ANDRE: I have a hard copy of that, so I can certainly follow along with the question if no one else may be able to.

MR. SHEPHERD: I will ask the question and you may be able to answer off the top of your head anyway, if I know you.

I am looking at the Woodstock bill comparison and the distribution has gone way up, but then the transmission costs go way down. And so, for example in this customer with 177 kilowatts of demand, the sample customer you are using, their transmission charges go down from $892 a month to $596 a month, a 33 percent reduction. And it appears to be all entirely driven by a reduction in the unit cost.

And that's true for all three of them, although the difference in the case of one of them is quite small. I wonder if you could just explain why this happens and why this is -- I looked for an explanation and couldn't find one.

MR. ANDRE: Yes, I don't know if there is an IR response that has an explanation to that, but I can certainly help you, Mr. Shepherd.

The RTSR rates that the acquired utilities were charging their customers, the last time they were sort of rebased would have been at their last cost allocation model. So Woodstock, when would that have been? 2012 or '13, somewhere around there.

MR. SHEPHERD: Yes, '11 or '12.

MR. ANDRE: And then from then on under the IRM, they just used the Board's RR, revenue requirement work form, which all it does is it looks at the change in transmission charges and then bumps up everyone's RTSR rates as necessary to recover what the forecast transmission charges are going to be in the future.

When we do it in 2021, we are now looking at and we are using data that comes from Mr. Alagheband's shop in terms of meter data for the actual customers, either smart meter data or interval meter data, and looking at the contribution of this class to the peaks. And what we are finding with the more current data is that these general service customers are contributing less to the peak -- and remember the peak is what transmission charges are based on -- than what was assumed they were contributing to the peak back when the utilities were calculating those rates.

So I think the explanation is something as simple as they were using data from 2012, 2013, on that relative contribution to the peak. In 2021, we are now using the latest data available to us on the contribution of this class to the peak. And the reality is -- and to that I can't speak. I don't know if general service customers either had been better at implementing efficiencies, or better at avoiding the peaks for other reasons, ICI reasons for example. But for whatever the reason is, the latest data shows that they are contributing less to the peak, and therefore by contributing less to the peak they are attracting a smaller amount of the share of transmission charges.

MR. SHEPHERD: So that's what I thought. And -- but this comparison appears to imply that the rates, if they had not been acquired, would be that much higher. But what your explanation is, is in fact that the transmission costs would have gone down anyway no matter who owned them; right?

MR. ANDRE: I don't know what the approach is for these acquired utilities in terms of updating their load shapes. I mean, they seem -- you know, if they continue to use the revenue-requirement work-form approach then it wouldn't have changed.

All we can comment on is the rates that they were paying at the time of acquisition, and if those rates were escalated, then -- and actually, in the case of Woodstock here you can see that the escalated rates for Woodstock actually dropped. We said back in 2014 they were $902, and now in 2021 the escalated rate is actually only 892, so we did show a bit of a drop, but it's not related to them having adopted different load shapes, but I can't comment on what the utility would have done with respect to the transmission charges that it applied to its customers.

MR. SHEPHERD: Would it be correct to understand this difference is as Hydro One -- I guess because you have more resources and you have more expertise in the area of rates, you took a more thorough approach to figuring out what they should pay for transmission and in effect corrected what the acquireds had been charging to a more appropriate level; is that fair?

MR. ANDRE: It's the same approach, yeah, that we use for all of our rate classes. Whenever we file a cost-of-service application we revisit the contribution to the peaks and therefore the amount that should be paid for transmission for all of our rate classes, in this case the acquireds included.

MR. SHEPHERD: All right. That's all my questions, thank you.

MR. SIDLOFSKY: Thanks, Mr. Shepherd.

Just before we move on to Mr. Buonaguro, Mr. Stephenson?

QUESTIONS BY MR. STEPHENSON:

MR. STEPHENSON: Oh, thanks. I think I can just put my stuff in writing if that's okay with you, and if I can just get an undertaking on that.

MR. NETTLETON: Gladly undertake that, Mr. Stephenson.

MR. STEPHENSON: Thank you very much.

MR. SIDLOFSKY: That will be JT3.22.

UNDERTAKING NO. JT3.22: TO PROVIDE ANSWERS TO MR. STEPHENSON'S WRITTEN QUESTIONS FOR HONI PANEL 3.

MR. SIDLOFSKY: And Mr. Buonaguro.

QUESTIONS BY MR. BUONAGURO:

MR. BUONAGURO: Thank you. Good afternoon, panel. I can tell you only about 100 percent of my questions are for Mr. Andre, so...

MR. ANDRE: Everyone else can go home.

MR. NETTLETON: Just about.

MR. BUONAGURO: Approximately, only.

And I am going to start with just a handful of questions on behalf of Arbourbrook Estates.

MR. ANDRE: Okay.

MR. BUONAGURO: And the reference is at Exhibit I, tab 46, Schedule EBE2, and I am looking at page 2. That's under the load -- or load and revenue forecast bucket of IRs.

So I am looking at the response to part D as a way to get into this. So to summarize, as I understood it, because I asked the question, Arbourbrook asked the company about a certain area of Hydro One's service territory that was at least at one point in time designated as R2 in terms of density. And the answer we got in terms of explaining what's happened to that area was that in mid-2013 the density for that area was reviewed, it was reclassified as an R1 density area, and then on approximately -- or, sorry, on May 2015, after -- and I am reading here:

> "After approval of the density review process and results by the Board as part of EB-2013-0416, the new classification was implemented."

So the clarification is this: I understood from that that, while it was true that in 2013 they were recognized as R1 notionally, not all, if any, of those customers were actually transferred over to R1 rates until mid-2015; is that what happened?

MR. ANDRE: That's correct. So the rate class review that was adopted in 2013 represented a new approach to identifying density classification. It made use of our GIS, graphical information system. And so we had an exhibit that fully described this new approach to classifying density, we put it in front of the Board, and we wanted the Board's assurance that what we were doing was appropriate. And so we weren't going the make any changes under this new density classification approach until the Board had a chance to review what was being proposed and agreed with what was being proposed.

And so at the time that they made their decision, which was, you know, for implementation of rates in May 2015, as soon as the Board's decision was made we implemented that change.

MR. BUONAGURO: Now, prior to that May 2015 implementation, which I guess is the holus bolus about the implementation for all the customers in that new rate zone, isn't -- and this is the understanding I got from the correspondence, so maybe I have got it wrong -- my understanding is that individual customers were contacting you with information about their density zones and on a one-off basis some customers were being transferred into R1 and given R1 rates. Was that happening or not?

MR. ANDRE: No. So when we submitted our application, until such time -- so any requests that came in at that point in time after we submitted our application with this new approach to density being proposed in the application, no further changes were made until such time as the Board ruled on that approach.

MR. BUONAGURO: So how about just before you put in the application?

MR. ANDRE: Yes, but it would have been -- it wouldn't have been under the GIS, you know, the new GIS system being used. So under the old approach, I don't know if these customers would have been classified as, you know, medium density.

MR. BUONAGURO: The e-mail exchange that was attached to the IR suggested on its face that people were contacting, I believe it was in 2013, asking about the density, in that individual customers were actually being changed. You are saying that that may have been the case, you can't confirm right now, but you are saying the second you applied to the Board leading in EB-2013-0416 for rates effective 2015, I guess --

MR. ANDRE: Yes.

MR. BUONAGURO: -- you stopped doing that and waited for the Board to determine a new regime, I guess, as we can call it --

MR. ANDRE: New regime to ident -- yeah, that's my understanding, that -- so I don't work in customer service. I don't know if any customer requests went through under -- you know, before the word got out, but I do remember there was exchanges with customer service that, you know, we filed this application. Until such time as the Board ruled that this new approach to identifying density classification is appropriate and should be implemented, we should hold off on making any changes, so that was the instructions that went out from regulatory.

MR. BUONAGURO: Now, currently and under this new regime when it comes to reclassification, what happens when you change a density classification? And we will use the R2 to R1 as an easy example. So if you change an area, let's say next year after 2018 rates are set, from R2 to R1, the customer obviously gets the benefits of R1 rates now? And it may not matter as much under DRP, I understand that, but --

MR. ANDRE: Right, right.

MR. BUONAGURO: -- technically your revenue requirement changes from -- based on who -- or could change -- maybe that is what I am asking -- so they would get the benefit of R1 rates.

What happens to the company in terms of the impact on the company when those -- that rate change happens? For example, if they are going from R2 to R1 do you continue to collect triple RP from that customer or on behalf of that customer, and when you go from R2 to R1 would you continue to collect DRP for that customer?

MR. ANDRE: No, so when -- you know, in your example, the customer that moved from R2 to R1, we would have set rates and -- on the assumption that they were going to remain as R2, but now that they have moved to R1 Hydro One would collect R1 rates, so, you know, for those customers who would be collecting slightly less revenue than had been anticipated at the time of the application.

MR. BUONAGURO: So now on the DRP there's DRP for both R2 and R1, so maybe that's not the best example, but on triple RP you would actually stop collecting RRRP for that customer?

MR. ANDRE: So I am not involved in the settlements of triple RP, but if I recollect, the regulation does require annually for you to identify the number of R2 customers, and you get funding from the government in accordance with how many R2 customers you gave the RRRP credit to, so, yes, we would stop getting the RRRP credit.

MR. BUONAGURO: All right. Thank you. Those are my questions on behalf or Arbourbrook Estates. The rest of my questions are on behalf of the Balsam Lake Coalition. And I am going to start with cost allocation rate design IRs. The first question I'd like to talk about is Exhibit I, tab 49, schedule BLC 5, and there's two specific questions.

So essentially, this IR asked you to run the cost allocation model under two scenarios. You didn't do either of them and I was very disappointed.

The first one asked you to take the existing cost allocation and split the seasonal class into three sub components, UR, R1 and R2 -- seasonal customers, I call them. And the second one asked you to do something slightly different. It asked you to actually take the UR customers that are in seasonal and put them into UR, and take the R1 customers that are in seasonal and put them into R1, and leave the R2 seasonal customers in seasonal with some very specific caveats, tell me what happens.

And the refusal, if I can call it that, was that this would require running a new cost allocation model, that the information wasn't readily available and you couldn't do it the timeframe for IRs, which I think was something like two-and-a-half weeks or so.

Can you do part B before the hearing? And I am assuming we don't have a settlement conference, because there wasn't one in the original PO. But given that I think we have a month and three quarters before the next step is completed, which means the hearing is going to be something like two-and-a-half to three months away at the earliest. Is that something you can do?

MR. ANDRE: So I am sure as you appreciate, Mr. Buonaguro, the issue is that even for part B, it will mean getting a load forecast and load shapes and all of the, you know, NCP and non-coincident peak and coincident peak inputs that go into the cost allocation model for a brand new class.

Creating that class in the model...

MR. BUONAGURO: So is how is that a brand new class?

MR. ANDRE: Well, in this case, you are right. We could use the seasonal as the placeholder for the R2 seasonal.

MR. BUONAGURO: That is specifically what I am asking you to do.

MR. ANDRE: Right. So it really comes down to the ability to -- and so you said keep all the status quo density factors, weightings, et cetera.

MR. BUONAGURO: Yes.

MR. ANDRE: So really it's the load forecast, and I know that right now we are in the process of preparing our transmission application. There is quite a bit of work for both the rates and load forecasting group.

MR. BUONAGURO: I would point out -- and I submitted on Friday that I might bring you to the seasonal report.

MR. ANDRE: Yes.

MR. BUONAGURO: Which it seemed to my unexpert eyes that you have already done this at least once, and maybe twice in updating that report.

MR. ANDRE: Right. And so your parts I and II are essentially what's in that seasonal report because we moved -- we have created a class. But for R2 we have moved all of that and merged it into with all of the other R2 customers and created a load shape that reflects the combined R2 plus the seasonal moving to R2.

What you are asking here is seasonal that would have moved to R2 stay on their own -- in their own class, so we need unique load forecast and load shape for just that class. And I am not sure that that's even within, you know, within the three weeks.

MR. BUONAGURO: We are talking about three months.

MR. ANDRE: Two months, yes.

MR. BUONAGURO: I need something.

MR. ANDRE: I know, as you know, there's intended to be a separate proceeding to examine --

MR. BUONAGURO: I have questions about that, too, yes.

MR. ANDRE: To examine the removal of the seasonal class. So I am not sure of the value for the purpose of what we are asking for in this application of doing this work.

But I agree. Over two months, I'd have to confer with my load forecasting manager here as to whether that's something that's doable. But I can't imagine that in a two-month period, it wouldn't be doable.

MR. BUONAGURO: I want it. It sounds doable, subject to check. And if it's not, tell me and we will have to argue about it.

MR. ANDRE: I think that's what I'd like to do, if that's okay. I would like to take an undertaking to verify whether that is something that can be done in the time frame between now and -- you say two months.

MR. BUONAGURO: I need it before the hearing, ideally.

MR. ANDRE: I think I'd like to look into what would be required, and if it can done within that period.

MR. BUONAGURO: Great.

MR. NETTLETON: Mr. Buonaguro, I can't recall. Are you filing expert evidence?

MR. BUONAGURO: No.

MR. ANDRE: I will take that undertaking to examine whether it's doable and, if so, to -- so certainly the undertaking response will indicate whether it's -- if we can do it and if we can't do it, we will provide reasons as to why we can't. But I really would like to look at it a little more closely.

MR. BUONAGURO: Okay.

MR. SIDLOFSKY: JT3.23.

UNDERTAKING NO. JT3.23: WITH REFERNECE TO INTERROGATORY EXHIBIT I, TAB 49, SCHEDULE BLC 5, PART B, TO EXAMINE WHETHER A RESPONSE IS DOABLE OR IF IT IS NOT DOABLE; AND IF NOT WHY NOT.

MR. BUONAGURO: I am part way there. Thank you. And when you're looking at it, consider that I am not asking you to do part A. I am conceding that.

MR. ANDRE: Understood, no, I think we are on the same page there. You are asking about part B part, which is already done, so yes.

MR. BUONAGURO: Now, I am going to move on to Exhibit I, tab 51, BLC 7, page 1 of 2. And I had asked -- we had asked there for you to break out the difference between how much funding from DRP was going towards rates and how much was being provided for by customers in R1 and R2.

And at part B of that question, I asked you if you can -- as a result of DRP, you can essentially increase the revenue cost ratios for R1 and R2, and there will be no actual rate impact for R1 and R2 customers.

And you almost confirmed it. You said yes, except for the very low volume customers. So I wanted to follow-up on that in each class.

My understanding of looking at the updated bill impact tables, which I can get a cite for, if you need to. But my understanding is that for R1, the fixed charge is actually set at the DRP level, the threshold of $36.43, which means that even at zero consumption in the R1 class, there is -- they have already hit the threshold, so there's -- you can't increase the customer portion of rates any higher. Even if the revenue cost ratio goes up, all of that would go into DRP; is that true?

MR. ANDRE: So the fixed charge -- I mean, if we can bring up the evidence. I thought the fixed charge was actually around 34 bucks for the R1 customer.

MR. BUONAGURO: We can agree that the DRP limit in the answer is 36.43.

MR. ANDRE: Yes, that's for sure.

MR. BUONAGURO: If we pull up -- I can get you a cite. If we look up under general issues and we look at power workers union number 4 -- that's Exhibit I, tab 4, PW 4, and we go to PWU 4 in the general, issue number -- sorry, I'm scrolling back here, issue -- tab 4. So is that would be issue 4, I guess. And if we go down to, I guess, the first R1 table.

MR. ANDRE: The next one.

MR. BUONAGURO: I am looking at proposed charge.

MR. ANDRE: Yes, and then scroll down, Erin, that's UR -- keep going.

MR. BUONAGURO: You have to go about three or four passed that, yes.

MR. ANDRE: Keep going, you are almost there. You are in the right place, just scroll down where you are.

MR. BUONAGURO: One more.

MR. ANDRE: Keep going.

MR. BUONAGURO: That's it.

MR. ANDRE: Right.

MR. BUONAGURO: So we look under service charge, proposed charge, it's 36.43, which is the same --

MR. ANDRE: Now, that's because this is an IR that specifically asked for bill impacts under PW.

But yes, to your point, the proposed rate is actually 37.79 which would be to your point larger than 36.43.

MR. BUONAGURO: I was going to ask you about that because if you look at the next one, if you look at R1, the next page -- or the next consumption level, it says 37.79.

37.79 was the proposed fixed charge without DRP, wasn't it?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: So the distribution volumetric rate, I got .0218 proposed rate, proposed charge zero.

MR. ANDRE: Yes. So what this is showing is that under that proposed rate column, you see what would have been charged if not for the Fair Hydro Plan. But under the proposed charge column what you see is what is charged under the Fair Hydro Plan. So just to make use of this same template --

MR. BUONAGURO: Okay.

MR. ANDRE: -- we showed you what they were, but then we overwrite it by the charge that would apply under the Fair Hydro Plan, because that's what this interrogatory asked us to do.

MR. BUONAGURO: That's very helpful, thank you. So as I understand it, there is a volumetric charge even for --

MR. ANDRE: Oh, absolutely.

MR. BUONAGURO: -- customers that are receiving DRP --

MR. ANDRE: Yes, yeah, it's --

MR. BUONAGURO: -- but it basically -- there is a low consumption level where it becomes irrelevant.

MR. ANDRE: Well, I mean, in this case, so this customer would have paid 37.79 and then .02 cents times whatever the consumption is. She's on the 750. So they would have paid that as the volumetric charge, but those two charges get overwritten by the 36.43 under the Fair Hydro Plan.

MR. BUONAGURO: All right. So that helps me understand what happened there.

Can you quantify the effect that you're talking about in part B of that interrogatory, which is at what consumption level for R1 and R2 is sort of the break point where they start -- they no longer are affected by their volumetric charge? Beyond which they can't pay any more? And then how many customers are underneath those levels?

MR. ANDRE: Right, so now that we have had this discussion, Mr. Buonaguro, I believe that that comment -- because I remember doing these calculations, and certainly under 2017 rates there would have been some customers that would have fallen below the 36.43, but at the proposed 2018 rates, you know, based on what we just looked at, there would be no consumption that would get them below 36.43, because the fixed charge alone is 37.79.

MR. BUONAGURO: Okay.

MR. ANDRE: So I think that's a correction. I would correct that response to say confirmed.

MR. BUONAGURO: For both classes or just R1? Because R2 has a much lower initial fixed charge throughout. If you go over another few pages.

MR. ANDRE: 25, yeah, so I guess there you're right. So I could undertake to show it. So for R1 it says we discussed there wouldn't be any. For R2 it would look like there would be some consumption.

MR. BUONAGURO: So I am looking for how many -- how much consumption -- what's the break point where they start

-- the rates no longer go up? So what volumetric amount do they hit the cap --

MR. ANDRE: Right.

MR. BUONAGURO: -- and then how many customers are at that or below or sort of below that?

MR. ANDRE: So I think I can short-circuit things a little bit, Mr. Buonaguro. Let's look at what's on the screen right now.

MR. BUONAGURO: Okay.

MR. ANDRE: So at 450 --

MR. BUONAGURO: Yes.

MR. ANDRE: -- consumption the -- what you see is a $25 fixed charge, and then you see the volumetric rate there of 3 cents, 3.59 cents, which generates an additional $11.41, so those two together are 36.41, which is essentially the Fair Hydro Plan amount.

So I would say at around 450 kilowatt-hours is where the saw-off is.

MR. BUONAGURO: I did the calculation, and it's something like that, but the part I can't do is figure out how many of those customers -- how many customers in R2 are at that consumption level or below.

MR. ANDRE: Okay. So that's what you are looking for?

MR. BUONAGURO: That part I need -- well, yeah, and then you can confirm the actual number when you do that, so thank you. That's an undertaking.

MR. ANDRE: Yes, we can do that.

MR. SIDLOFSKY: JT3.24.

UNDERTAKING NO. JT3.24: TO ADVISE HOW MANY CUSTOMERS IN R2 ARE AT THE NOTED CONSUMPTION LEVEL OR BELOW.

MR. BUONAGURO: Thank you.

Now, I got to find my place again...

Now, I had asked the question of panel 1 by accident what -- how much DRP was -- is in the application. So essentially how much distribution rate protection does the updated evidence require for R1 and R2. That witness couldn't answer the question. It was pointed out to me that you actually answered the question in CME 91, so Exhibit I, tab 51, CME 91. And at part B it shows revenue funded through DRP, 119 million for R1 and 134 million for R2.

MR. ANDRE: Yeah, that's -- it's an estimate. Like, there will be those low-volume customers that might not be subject to it, but that would be fairly close to the amounts, yes.

MR. BUONAGURO: Okay. And just to confirm that -- it probably says in the question, but that 134 million for R2 is after our RRRP. That doesn't include RRRP funding. That's separate.

MR. ANDRE: That's separate, yes.

MR. BUONAGURO: Okay. So I -- and -- roughly that puts it around 250 million or so; correct?

MR. ANDRE: Sure, yeah.

MR. BUONAGURO: So if we go to the general-issues interrogatories. And going to Exhibit I, tab 5, Schedule BLC 4, part B talks about attaching a white paper called "addressing affordability", which I did some -- ask some questions on, I think it was Friday. It feels like an eternity ago.

And at page 7 of that attachment, scroll down to page 7, and this is where I actually asked that first question, how much is actually in there, and I couldn't get that answer on the spot, which was fine.

If you go to page 7, this is the part of the white paper that talks about rural delivery rates at the top, you can see that, and it talks about Hydro One's proposal to the provincial government, and it talks about, at the last sentence of the first column:

"This would require an additional $200 million in rate subsidy for Hydro One's rural non-seasonal customers."

Can you briefly talk about -- first of all, I am assuming that you were involved in the calculation of the 200 million; is that fair?

MR. ANDRE: It was -- I was asked for some estimates, rough estimates, of what it might cost, yes.

MR. BUONAGURO: Okay. Do you have a sense of what the drivers were between the 200 million and the 250 million that's actually in rates -- in the rate proposal?

MR. ANDRE: So at the time we did this we wouldn't have had our proposed -- our proposed application, we wouldn't have had -- I don't think we had -- when did this go? January 30th, 2017. Umm... No, it's simply a -- I am pretty sure that I would have used either 2017 or I might have even used 2016 rates to estimate that versus the number that you referred to me in CME, which is based on the forecast -- 2018 forecast numbers.

MR. BUONAGURO: And the reason I ask the question, it's not some fundamental change in concept, it's things like, here you used $38 a month as a threshold, the actual threshold is 36.43, that's an extra buck 50 per month per customer, for example.

MR. ANDRE: Yeah. Yes, that's another example of simplifying assumption --

MR. BUONAGURO: Okay. And then -- and then the revenue requirement has gone up relative to whatever was used in here, things like that?

MR. ANDRE: Yup.

MR. BUONAGURO: Okay, thank you.

Now, you mentioned this in response to my other question, Exhibit I, tab 1, BLC 1. This question asked you -- or asked the company -- and I think you answered -- about the outstanding EB-2016-0315 proceeding, which is -- I guess we will call it the elimination of the seasonal rate proceeding. And at part B you referred us to -- well, I asked:

> "Please provide information provided to Hydro One from the OEB with respect to taking steps towards elimination of seasonal rate class."

And at the end I put:

> "Including but not limited to the continuation of the EP-2016-0315 proceeding."

The letter, which is attached at Exhibit I, tab 16, CCC 17, isn't -- as described in e-mail exchange with Board Staff seeking clarification on information provided in the updated report. That was dated -- oh, it's on the screen already, look at that -- June 21st, 2017, so last year, between yourself and Board Staff.

It doesn't specify it in the answer, but I assume I am to infer from the question coupled with the answers that that's the last time you have heard from the Board about that proceeding?

MR. ANDRE: Yes, that's correct.

MR. BUONAGURO: And I assume from that also that Hydro One hasn't taken any steps towards contacting the Board about the proceeding or updating itself with respect to the proceeding?

MR. ANDRE: You know, I may have called or if we run into each other, because I do see Harold at some functions sometimes. I may have asked so what's happening with that proceeding, but nothing official.

MR. BUONAGURO: You drew Harold into this, I didn't.

MR. ANDRE: Sorry, Harold.

MR. NETTLETON: Actually, it was your question.

MR. BUONAGURO: But I didn't mention Harold.

MR. NETTLETON: You mentioned Board Staff.

MR. BUONAGURO: Fair enough. Okay, so I take it Hydro One's position is it's content to wait and see?

MR. ANDRE: Yes. I mean, we are in the Board's hands as far as neck steps. We have put a report together that I think very clearly identifies what happens with the elimination of the seasonal class, and I am sure you have read the report.

You know, we have identified very clearly our concerns with what happens to R2 customers with the elimination of the seasonal class. We have identified our concerns around, at the time the decision was made, the move to fixed rates wasn't discussed at the hearing. The impacts of the move to fixed rates wasn't discussed at the hearing.

I mean, there were a number of things that were raised in that report that I think the Board and all intervenors need to have a look at. So we are in the Board's hands as far as what to do with that record.

MR. BUONAGURO: Thank you. Now, I have to ask, because it seemed add to me. Part C asked you to confirm that that proceeding actually made all your rates interim, and I asked you to confirm is that still the case. And you confirmed that was.

Is that not of a concern to Hydro One, that all of your rates are interim as a result of that proceeding, and presumably will continue to be so until it's resolved?

MR. ANDRE: It certainly raises an issue that all of the rates for all of our rate classes would be subject to change as a result of making a change on the seasonal class. But that would, you know, that would depend on how the Board decides to implement the change. Like any decision they make out of that proceeding to review the report, I think would have -- you know, would be implemented and if it really did mean going back to the date when the rates were set interim, yes, that will present a number of challenges.

MR. BUONAGURO: Looking at Exhibit I, tab 4, schedule BLC, at part B, you say -- and I am asking questions here about the applicability of regulation 198/17. And the answer was:

"Regulation 198/17 applies specifically to customers in the R1 and R2 year-round residential classes, and the criteria in the regulation that a qualifying customer must reside 'continuously at the service address to which the account relates for at least eight month of the year' was specifically added to the regulation so as to exclude seasonal residential customers from getting the DRP should seasonal customers be included in the R1 or R2 rate classes at some point in the future."

And then later on, and this is at Exhibit I, tab 5, schedule BLC-4, which we were talking about briefly before -- this the time I am not looking at the attachment. I am looking at part D of the answer.

This answer was:

"Hydro One was part of the Ministry of Energy working group that provided input to the ministry staff that developed the distribution rate protection component of the Fair Hydro Plan. Hydro One informed ministry staff of the OEB's decision with respect to the elimination of the seasonal class and the potential for seasonal customers being included in Hydro One's R1 and R2 year round residential rate classes."

The combination of responses suggested to me that it was important to Hydro One that the distribution rate plan or protection that was implemented by the province excluded seasonal customers, including if and when seasonal customers end up in R1 and R2.

Is that true? And, if so, why?

MR. ANDRE: No, that's not correct. The combination of the two responses, what they point to is the fact that the ministry staff indicated at those working meetings the intent that it just be R1 and R2 customers that received the distribution rate protection.

We asked about seasonal customers, you know, are they eligible, should they get the protection. Ministry staff made it clear that no, our intent is just to give the rate protection to those customers -- and they didn't use these Words, but notionally the ones who are needing to make a decision between heating their home or putting food on the table. And so we want it focussed on residential customers.

So it was at that point that we said, well, if you want it focussed on residential customers you should be aware that this plan is in place and if you just say R1 and R2 classes, at some point seasonal customers may be in R1 and R2 classes. So if that's your intent, then you may want to think about how to write the regulation in such a way as to deliver your intent.

MR. BUONAGURO: Thank you. But if we go back to the working paper or the white paper at A, and go back to page 7, I asked about this on Friday and I was told -- I asked the question what was this in response to, like how did this white paper come into existence. My understanding is Hydro One was asked to prepare some kind of proposal and I asked what were the parameters or instructions that Hydro One was given, and the answer was there wasn't anything in particular; it said provide us your proposal.

And so the question I had for that witness was, well, how come your proposal -- what was it that led Hydro One to its proposal on rural delivery rates at the bottom of this page that excluded seasonal customers from the proposal for DRP. And I think it's fair to say I got a refusal on that answer.

It's slightly different than what you are telling me now in respect to my question about why you were excluding on R1 and R2 -- sorry, why you were excluding seasonal customers when determining R1 and R2 eligibility.

MR. ANDRE: No, no --

MR. NETTLETON: Mr. Buonaguro, in fairness, the response that you got from Hydro One's witnesses when you last discussed this piece of the evidence was that there were four recommendations, and three of the four recommendations provided and addressed all rate classes including seasonal customers.

So I don't think it's fair to say that you were told that there was a refusal. I think what the witness provided you with was a response. Mr. Merali indicated there was benefit flowing to seasonal classes and that that was the intent was in Hydro One's ongoing challenges of balancing competing interests and balancing various rate classes that they had to provide -- or they chose to provide a report to government relating to rural delivery rates, and chose the language that's found here.

I don't think we are going anywhere new, or I don't see any value in re-litigating this with this witness.

MR. ANDRE: I would like to add one thing, though. You said that I had said that my answer somehow contradicted what was in this report and what Mr. Merali said. And just to be clear, what I had said was during a working group -- so this is after the ministry made the decision to go ahead with the Fair Hydro Plan, they got together the utilities that would be impacted by this just to talk about implementation and scope out all the issues.

And I think I was very clear that I said it was the ministry staff who said they intent was not to include seasonal. We raised the possibility of including seasonal; ministry staff indicated that, you know, their focus was on customers who have to live and work in rural areas and provide them subsidies.

So I don't believe -- I disagree a hundred percent that I somehow contradicted what Mr. Merali said. My reference was to the working group.

MR. BUONAGURO: Thank you for that. What I'd -- in reply, that possibility isn't raised in the proposal dated January 13, 2017, and the working group, as I understand it is subsequent to that.

So I was trying to get at what led Hydro One to exclude it from the January 13, 2017, white paper.

The answer I got -- and I understand the answer I have been given so far is there are three other parts to that proposal which benefit seasonal customers as they do all other customers. I've never asked about those three Proposals. I am not questioning those three proposals. I am not terribly concerned about those three proposals. I am asking one particular proposal, and the answer I keep getting don't look at that proposal; look at the other three. I don't -- I'm not going to argue again about it being a refusal or not. We can leave it at that and I will move on.

MR. NETTLETON: I think that is probably the best.

MR. BUONAGURO: Okay, great, thanks. I am just checking here. Actually, I will ask you one more and this one's for me, if I can put it that way.

Deferral and variance accounts, Exhibit I, Tab 57, BLC Number 8. I think you might remember this one because it -- I asked about under the distribution protection regime, DRP doesn't apply to variance accounts. And it just seemed weird to me that there's a distinct possibility under that regime that if there are credits accruing to ratepayers in variance accounts subsequent to a rebasing year like this one, the proposal would be to pay those credits back to all customers, including R1 and R2 customers, who would not have paid those amounts in the first place because those amounts would have been absorbed by the DRP funds.

Now, on the opposite side of that, where there is a debit owing from customers to the company, they would be paying to the company amounts that notionally, at least, they should have been protected from through DRP. And I asked about that. The answer I got was.

MR. ANDRE: See panel 3.

MR. BUONAGURO: It is what it is or something like that, and it didn't really engage in sort of the philosophical issue that I was trying to struggle with. So I was wondering whether you had anything further to add on that. Have you thought about it in those terms, that it's weird to pay back money to customer who is didn't pay it in the first place, for example?

MR. ANDRE: Mr. Buonaguro, I heard your exchange with the panel and I totally understand your point. I know exactly what you are referring to in terms of what appears to be a contradiction.

The DRP is a subsidy. They landed on 36.43, but they could have landed on any other number. So it's a subsidy to get customers from R1 and R2 customers from what they would have paid down to 36.43. So admittedly, to the extent that the rider was associated with base rates -- and most riders aren't; most riders are related to RSVA accounts, et cetera, which have nothing to do with base rates -- but I take your point that sometimes there can be; like a foregone revenue rider, for example, can be very much tied to base rates.

To the extent they are tied to base rates, customers, R1 and R2 customers may be either over, you know, getting less of a subsidy or getting more of a subsidy. But this came up during those working group meetings, and the settlements associated with just recovering the base rates and the exchange that needs to go on between Hydro One and the ministry to settle that has a level of complexity and trying to introduce riders into that the settlement mix introduced a whole other level of complexity, way up there.

So I think that was part of the reason that the drafters of the regulation specifically recognized that that was an issue and therefore specifically wrote into the regulation that riders and adders are outside the scope of this -- recognizing, like I say, that there might be -- the subsidy might be a little bigger or a little smaller in some years, but that was far outweighed by the issues around trying to settle for riders.

MR. BUONAGURO: Thank you for that. Those are my questions. Thank you.

MR. SIDLOFSKY: Thanks, Mr. Buonaguro. We are going to take a ten-minute break. But just before we do, Mr. Aiken has asked if he can ask his one question on the phone line.

QUESTIONS BY MR. AIKEN:

MR. AIKEN: Thank you for letting me sneak in here. My question is on Exhibit I, tab 47, CME Number 79. In attachment 1 to the response, which shows sales, billing peak and peak to energy ratios for 2017 through 2022, am I correct, first of all, that the 2017 is data shown is forecast data?

MR. ALAGHEBAND: Yes, that's correct.

MR. AIKEN: Then with the exception noted in the right-hand column, the megawatt forecast is based on a peak to energy ratio that is the same for each year of the 2017 through 2022 period. So my question is: Are these forecasts that the peak to energy ratio figured, are they based on actual historical data? Or are they based on the forecast for 2017? Or some other methodology?

MR. ALAGHEBAND: The 2017 was used as a basis for comparison. And for that number to arrive at, we wanted to have some normalized figure. Because 2017 is the forecast year, it cannot be actual, so it is a kind of weather normalized ratio that we had and we went from there on. We said, okay, this is what number we are comfortable with, and then after that, we kept the ratio the same except for those two cases --

MR. AIKEN: Okay, so it's based on basically a normalized forecast for 2017.

MR. ALAGHEBAND: Yes, that's right.

MR. AIKEN: And throughout the technical conference you talked about updating various IR responses when you have actual 2017 data.

MR. ALAGHEBAND: Yes.

MR. AIKEN: Does that include this attachment 1 to CME 79? Will you be updating it for 2017 actual data?

MR. ALAGHEBAND: If you go to Staff 219. Actually there is an updated forecast for peak by rate class. So that would be equivalent of whatever table was there in the original forecast, which I can direct you to; table E8A and E8B. So the E8A includes the actual of 217, and E8B includes '17 as the weather normalized actual. And then from there on it goes accordingly.

MR. AIKEN: Okay so was Staff 219?

MR. ALAGHEBAND: Yes

MR. AIKEN: Okay, thank you. Those are my questions.

MR. SIDLOFSKY: Thanking Mr. Aiken. We are going to take a 10-minute break -- sorry?

MR. NETTLETON: Just before we break, Mr. Sidlofsky, does anyone have any questions for Mr. Boldt? I have one, but.

MR. LADANYI: I have one as well.

MR. FERGUSON: Energy Storage Canada he replied to one of our interrogatories so I suspect we have some for him.

MR. NETTLETON: Okay, perfect. Then I don't have any. Can we take our break?

MR. SIDLOFSKY: Thank you. Ten minutes.

--- Recess taken at 5:17 p.m.

--- On resuming at 5:31 p.m.

MR. SIDLOFSKY: We have two more intervenor representatives to ask the last questions of the day today.

Just before we do that, I would note that Mr. Brett has, I believe, one additional question. He is planning to submit that in writing, so I'd ask for an undertaking that Hydro One respond to that question when it comes in. That would be undertaking JT3.25.

MR. NETTLETON: We will undertake; we will make that undertaking.

UNDERTAKING NO. JT3.25: TO PROVIDE RESPONSES TO MR. BRETT'S QUESTIONS FOR HONI PANEL 3

MR. SIDLOFSKY: Thank you. And Board Staff will also submit their questions in writing, so I'd appreciate an undertaking to respond to those questions as well.

MR. NETTLETON: Agreed.

UNDERTAKING NO. JT3.26: TO PROVIDE RESPONSES TO BOARD STAFF'S QUESTIONS FOR HONI PANEL 3

MR. SIDLOFSKY: And that will be undertaking JT3.26. And the second last representative of the day, Mr. Ladanyi for Energy Probe; I believe you just have a few questions.

QUESTIONS BY MR. LADANYI:

MR. LADANYI: That's right. Good evening, panel -- I was waiting to say that, by the way. My name is Tom Ladanyi, and I am a consultant with Energy Probe, and I promised Mr. Boldt that I would ask him a question. So this is a follow-up of something that we discussed yesterday, I believe, or -- not yesterday, but on Thursday -- and it has to do with a metered dispute charge.

So could you turn to Exhibit E1, tab 1, schedule 2, page 7, and I see Mr. Boldt's name is at the bottom of that exhibit. That's E1, tab 1, schedule 2, page 7.

MR. ANDRE: Can we get it up on the screen? Okay.

MR. LADANYI: So we have it up. Do you have it there? Good.

MR. BOLDT: Yes, just give me a second.

MR. LADANYI: Sure.

MR. BOLDT: Yes.

MR. LADANYI: Very good. So the meter dispute charge is rate code 24 on the spreadsheet, and I wanted to see what the revenue forecast was from rate code 24 and I looked at, for example, 2017. I see fifty units of volume and a total of 1500, which corresponds to the $30 that you are currently charging. That's how you came up with that number, I presume.

And then I looked across to the subsequent years and I had expected actually 50 times 290, which is what you were proposing to charge, but actually it's not there.

What you were charging, and I figured it out very quickly, if you look to another exhibit -- if you switch to Exhibit H1, tab 2, schedule 3, page 45. So let's try again. Exhibit H1, tab 2, schedule 3, page 45, it's table 16, meter dispute charge, Measurement Canada.

There it is, table 16, and I see what you have done, actually. It appears that instead of using the $290, which is in the very last column of that page, you actually used the calculated total charge. So that's why it varies.

And my question is why did you do that? Why would you not have used $290 in the previous exhibit?

MR. BOLDT: Sorry, on page 45, in the calculation of our costs for meter disputes, based on the time -- the average times in the time study --

MR. LADANYI: Yes, I accept those calculations entirely. I am not questioning that. I am questioning why in the previous exhibit, which we looked at a second ago, you didn't use the $290 amount. You used actually the calculated charge because that exhibit really, in my mind, is a forecast of your revenues and the numbers are very close together.

I am not -- I am just puzzled by it, that's all.

MR. BOLDT: Sorry, what was the first reference, which table?

MR. LADANYI: The first reference was -- okay, there we go. It's E1, tab 1, schedule 2, page 7.

MR. BOLDT: So all our revenues that we calculated when Mr. Merali was on the stand, I believe Friday afternoon, he talked about smoothing some rates that were associated to kind of his shop, if you will.

And when we were calculating revenues, what we actually used -- we didn't use the smooth rate to calculate the revenue. What we did was we used the revenue calculation using the actual charge.

MR. LADANYI: Yes, and my question is why did you do that.

MR. BOLDT: We based all our revenues. Some of them actually went down and some of them went up, but they were all based on the actual cost to do the work and that was the approach that we took.

MR. LADANYI: Okay. I still actually -- I won't belabour this point, but the other table was a forecast of revenues you would collect. It's actually not a forecast of costs you would incur, and that's the basis of my question.

MR. ANDRE: Yes. So I think what I heard Mr. Boldt say is for the purpose of preparing this table, they had used the actual calculated value. But I think we would all agree that from a forecast basis, it should be 290. The $4 difference really on the volume that we are talking about is de minimus, the impact on the revenue.

But we take your point and we understand that from a forecast perspective, it probably should have been 290 that should have been used.

MR. LADANYI: Very good, thank you. Now, I have another question. For this one, could you turn to Energy Probe Research Foundation Interrogatory No. 3, and it is Exhibit I, tab 4, Energy Probe 3.

MR. ANDRE: Yes, I have that.

MR. LADANYI: Yes, and here we ask you to essentially give a forecast of the bill impacts if you were to get everything you are looking for, and you provided a nice spreadsheet which is the next page -- and thank you very much for that, and I have a subsequent question about this.

Now, some of these charges are -- the impacts appear to be quite large. What is your proposal? Is your proposal is to collect these in 2019, or would you spread out this over several years -- or you haven't decided yet?

MR. ANDRE: Yes, so I don't think we have made a decision. You know, if at the time that the decision is made and we are preparing the draft rate order, if these were the impacts that were to materialize, clearly we would have to do something as they are above the 10 percent limit and, you know, I would imagine there's options in terms of recovering over a longer period, doing some sort of individual bill impact mitigation.

So we would take some action to bring those impacts on a typical customer down below 10 percent. But we haven't made any decision at this point what that would be.

MR. LADANYI: Thank you, Mr. Andre, these are all my questions.

MR. SIDLOFSKY: Thanks, Mr. Ladanyi. Finally, Mr. Ferguson. Are you going to be asking questions for both Anwaatin and ESC?

MR. FERGUSON: Right now, it's just ESC, Energy Storage Canada.

MR. SIDLOFSKY: Okay, thank you. Go ahead.

QUESTIONS BY MR. FERGUSON:

MR. FERGUSON: Good evening, panel. My name is Cary Ferguson and I am here on behalf of Energy Storage Canada. I have questions on your interrogatory responses to ESC 1 and ESC 2. We will start with ES C2, and that's Exhibit I, tab 51, schedule ESC 2, and we will start on page 3.

In your response to our interrogatory E there, you have noted that there were administrative errors in table

16 and table 19, and I just hope -- I am just wondering if you can undertake to update those tables to correct those administrative errors.

MR. BOLDT: Yes, we can do that.

MR. FERGUSON: Thank you.

MR. SIDLOFSKY: Undertaking JT3.27.

UNDERTAKING NO. JT3.27: TO PROVIDE CORRECTED DATA FOR IR RESPONSE EXHIBIT I, TAB 51, SCHEDULE ESC 2, TABLE 16 AND TABLE 19

MR. FERGUSON: If you could scroll up to page 2, the response to interrogatory B, we had asked that you describe how the system benefits provided by Energy Storage facilities were considered in CIA, connection impact assessment charges, for energy storage facilities.

And I've read your answer and I just want to confirm, does your answer -- should I take from that that you do not consider system benefits in the CIA charges for energy storage facilities? Those are not taken into consideration?

MR. BOLDT: In the calculation for the CIA or the work that's done -- excuse me -- the energy storage device, it's based or it's connected to the system based on the nameplate size of the device. And it doesn't, it doesn't take into effect not the X megawatt-hours of storage that it has. So it treats it as a load when it's connecting it.

MR. FERGUSON: So just as a load; no consideration of those other benefits that it might provide?

MR. BOLDT: Correct.

MR. FERGUSON: Thank you. And then I saw in response to C and D you said to refer to B above. I understand that makes sense in the context of question D, but our question C had been to update tables to show calculations for distribution connected energy storage and behind the meter energy storage. And so I was just hoping you could either undertake to update those tables, as we have had asked in interrogatory C. I just didn't understand how B applied to C in this case.

MR. BOLDT: Yeah, we can take a look at it and give you the taking.

MR. FERGUSON: Thank you.

MR. SIDLOFSKY: JT3.28.

UNDERTAKING NO. JT3.28: TO UPDATE THE RESPONSE TO PART C OF EXHIBIT I, TAB 51, SCHEDULE ESC 2

MR. FERGUSON: And now if we can, if I can have you turn to ESC 1. That's Exhibit I, tab 49, Schedule ESC 1, and go to page 2 of 2 there, please.

MR. ANDRE: Yes, I am there.

MR. FERGUSON: Great. This is for Mr. Andre. In response to number 2 there on lines 8 to 14, you're describing how you classify different customer groups, and on line 10 you say:

"Industrial and commercial load customers can be classified as general service energy, general service demand, urban general service energy, urban genera service demand, or sub transmission, depending on the usage level, density, connection voltage, and transformer ownership."

I was hoping you would be able to provide a table listing the thresholds and when those classifications change for each of those factors.

MR. ANDRE: So our rate schedules that are included in evidence would -- at the top, it would describe what is required to fit into each of those categories. The usage level, I mean, I can -- general service energy is where demand is less than 50 kilowatt-hours, and then demand is when demand is greater than 50 kilowatts -- not kilowatt-hours, sorry, kilowatts. So is that's the usage.

Density -- I think that's evident in the name. The urban ones are the density; the ones that don't say urban are the regular. And then connection voltage and transformer ownership refers to subtransmission customers, so subtransmission customers have to be connected above 13.8 kV connected to a facility that's at that voltage or higher and they have to own their own transformer.

MR. FERGUSON: You anticipated my next question, Mr. Andre, thank you. So all those factors --

MR. ANDRE: Requirements.

MR. FERGUSON: -- requirements, thank you -- are in the rate codes?

MR. ANDRE: They are in the rate schedules, yes.

MR. FERGUSON: Sorry, the rate schedules.

MR. ANDRE: Yes.

MR. FERGUSON: Thank you. Just going through this in terms of going kind of back to the system benefits discussion we just had. I just want to confirm that there's no consideration in terms of when we are classifying energy storage. It's based on those factors in that paragraph we just discussed, Mr. Andre. There's no consideration of the system benefits?

MR. ANDRE: No.

MR. FERGUSON: No? Or the avoided or deferred benefits that they provide?

MR. ANDRE: No.

MR. FERGUSON: No consideration?

MR. ANDRE: No? I am aware that that has come up in some Board working groups in terms of the appropriate rates to set for energy storage. These aren't specific to energy storage. We are trying to fit, make use of existing rate classes, and so the existing rate classes there, it's sort of like fitting customers into one of those existing rate classes and there is no consideration of benefits.

MR. FERGUSON: Right; so it's not there yet?

MR. ANDRE: No.

MR. FERGUSON: Thank you. And how is net metering considered in these? How would net metering be considered in this?

MR. ANDRE: I think the last paragraph clarifies that.

MR. FERGUSON: Yeah.

MR. ANDRE: So, you know, if there -- if customers have a behind the meter, the BTM refers to behind the meter generation, then it's the metered generation on which customers are billed. So net metering is automatically considered for customers that are in the general service or general service demand or energy classes. And then for ST customers, behind the meter generation is actually added back because those customers are gross-load billed.

MR. FERGUSON: Thank you. I am just curious about the qualification here with October 1998. So ST customers with a BTM load displacement generator, or energy storage equipment installed after October 1998 at one megawatt or above, et cetera. Why the cutoff at October 1998?

MR. ANDRE: So that was the time that the energy market was opened. That's the time that Hydro One was not -- Ontario Hydro was broken up into the various component companies, and so as part of the application to set those first set of rates, the decision by the Board made at the time was that any generation that existed at this point in time would be grandfathered as being part of the base load.

So if they already had that generation in there, the load that you were seeing, the net load that you were seeing represented what that customer has historically provided. So basically they were grandfathered and it had to do with the opening up of the market and the breaking up of Ontario Hydro.

MR. FERGUSON: Thank you, that's very clarifying. Just one last question here. I am just trying to wrap my head around where storage fits into all these. Admittedly there's a lot of different factors at play here, so correct me where I am going wrong here, if I am going wrong.

The storage could be general service demand? Could fall into that category, energy storage?

MR. ANDRE: So, energy -- I mean, energy storage is, shall I say there's a lack of clarity on how energy storage customers should be treated. We have a distribution generation -- distributed generation class, and so there's some thought that they should be part of that class. Or, as Mr. Boldt just said, energy storage can be thought of as load customers. So if they are thought of as load customers, then any one of these classes could apply as well.

But I will be frank: There is some lack of clarity around -- I mean, it's so new, there is a bit of a lack of clarity around how to treat them. From a rates perspective, the thought or notion of treating them as load customers and having one of these classes apply to them, that represents our current thinking right now.

MR. FERGUSON: Right, so it could be in the demand category by not the energy category; right?

MR. ANDRE: It depends on the size of the energy storage.

MR. FERGUSON: And it would depend on those factors in the paragraph we discussed?

MR. ANDRE: Right. Correct.

MR. FERGUSON: Usage level, density, connection voltage and transfer ownership?

MR. ANDRE: Correct, correct.

MR. FERGUSON: Okay. Thank you, those are my questions.

MR. SIDLOFSKY: Thanks, Mr. Ferguson. I don't believe there are any other questions.

PROCEDURAL MATTERS:

One question I have for you, Mr. Nettleton. Any thoughts on timing for interrogatory responses? And of course I am referring only to the -- excuse me, undertaking responses. And I am referring only to the undertakings on questions that you actually have right now.

MR. NETTLETON: Mr. Sidlofsky, I don't think I have any comments right now. I think that just before we broke I think you indicated that there are 68 undertakings that have been given in this three-day proceeding, and of those, I think there are some that we haven't even seen yet, in terms of the level of questioning that some folks have provided by way of written response.

So I think that it's going to take some time to put these together, and it's certainly not a this-week task.

MR. SIDLOFSKY: Understood. Thank you. And thanks to our reporter for sticking with us well into the late afternoon.

MR. NETTLETON: Yes, thank you.

MR. SIDLOFSKY: And we are concluded.

--- Whereupon the conference adjourned at 5:51 p.m.