

ONTARIO ENERGY BOARD

FILE NO.	**EB-2025-0252**	**Alectra Utilities Corporation**

DATE:	**September 15, 2026**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	David Sword	**Commissioner**
	Shahrzad Rahbar	**Commissioner**

REVISED TRANSCRIPT

EB-2025-0252

THE ONTARIO ENERGY BOARD

Alectra Utilities Corporation

Presentation of a Settlement Proposal

Proceeding held in person and virtually
at 2300 Yonge Street, 25th Floor, Toronto, Ontario
on Tuesday, September 15, 2026, commencing at 10:03 a.m.

PRESENTATION

A P P E A R A N C E S

TIARA FEARON	Hearings Advisor, Ontario Energy Corporation
RAMAN DHILLON	Board Counsel
NARISA JOTIBAN PAULINE SHEN	Board Staff
DALIANA COBAN JONATHAN MYERS CHRISTINE LONG TOM WASIK NATALIE YEATES MARC VILLETT	Alectra Utilities Corporation
HENRY LIM	Project Manager
SHELLEY GRICE	Association of Major Power Consumers in Ontario
CLEMENT LI	Building Owners and Managers Association of Toronto
TOM LADANYI	Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC) and Energy Probe Research Foundation
LAWRIE GLUCK	Consumers Council of Canada (CCC)
DANIEL VOLLMER	Distributed Resources Coalition (DRC)
SCOTT WALKER	Ontario Association of Physical Plant Administrators (OAPPA)
MARK RUBENSTEIN	School Energy Coalition (SEC)
BILL HARPER	Vulnerable Energy Consumers Coalition (VECC)

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Toronto, Ontario

--- Upon commencing on Tuesday, September 15, 2026, at 10:03 a.m.

PRESIDING COMMISSIONER MORAN: Good morning, everyone, and welcome to EB-2025 -- we are here for an application from Alectra Utilities, EB-2025-0252. We have convened today to receive a presentation on the settlement proposal that we are being asked to consider for the purposes of setting base rates and to allow the Ontario Energy Board team to ask questions about aspects of it.

I am here -- my name is Patrick Moran. I am presiding commissioner. I am accompanied by Shahrzad Rahbar and David Sword. I am going to start first with the land acknowledgment. Ms. Fearon, if you could?

LAND ACKNOWLEDGMENT

T. FEARSON: Good morning. By acknowledging the land on which we operate, we recognize the unique relationship each of us has with the land and the Indigenous Peoples who have been living and working here for thousands of years. With these words, we renew our commitment to learning and reconciliation. The Ontario Energy Board acknowledges that our headquarters, in what is now called Toronto, is located on land covered by Treaty 13 and the territory of the Anishinaabeg Nation, Haudenosaunee Nation, and Wendat Nation. The long and rich history

of this land is marked by many other treaties and Nation to Nation agreements, including the Dish With One Spoon and Two-Row Wampum belt covenants. Traditionally this land was a meeting place for many Nations from across Turtle Island and is now home to many Nations, the Metis and Inuit. We are grateful for the opportunity to live, work, and learn on this land and we acknowledge our shared responsibility to all our relations as we work toward a sustainable, equitable energy sector across Ontario.

PRESIDING COMMISSIONER MORAN: Thank you, Ms. Fearon. We also want to acknowledge that the service territory served by Alectra also covers the traditional territory of many other First Nations, and so we didn't want to let that go unacknowledged, given that our decision will be implemented in your service territories. I am going to go to appearances now. Perhaps I will start with Alectra?

APPEARANCES

J. MYERS: Thank you and good morning. My name is Jonathan Myers. I am counsel to Alectra. With me here today is my co-counsel Daliana Coban. And from Alectra we have, to my right, is Christine Long, senior vice president of regulatory. Over on our panel today, on the left, we have Tom Wasik, senior vice president asset management. In the middle, Natalie Yeates, vice president regulatory, and Marc Villett, senior vice president finance. And helping

us out today as well is Mr. Henry Lim, project manager.

PRESIDING COMMISSIONER MORAN: Thank you, Mr. Myers. OEB Staff?

P. SHEN: Good morning, everyone. My name is Pauline Shen. I am from the regulatory accounting team. So I pass it on to Narisa.

N. JOTIBAN: Good morning, everyone. I am -- my name is Narisa Jotiban. I'm the case manager. Passing to Raman.

R. DHILLON: Good morning, everyone. My name is Raman Dhillon and I am OEB counsel.

PRESIDING COMMISSIONER MORAN: Are there other appearances?

M. RUBENSTEIN: Hi, good morning, panel. Mark Rubenstein, counsel for the School Energy Coalition.

L. GLUCK: Good morning. Lawrie Gluck, on behalf of the Consumers Council of Canada.

S. WALKER: Good morning. Scott Walker, on behalf of OAPPA.

C. LI: Good morning. Clement Li, on behalf of Building Owners and Managers Association.

T. LADANYI: Good morning. Tom Ladanyi, on behalf of Energy Probe Research Foundation and the Coalition of Concerned Manufacturers and Businesses of Canada.

S. GRICE: Good morning. Shelley Grice, representing the Association of Major Power Consumers

in Ontario.

B. HARPER: Good morning. Bill Harper, on behalf of VECC.

D. VOLLMER: Good morning. Daniel Vollmer, counsel for Distributed Resource Coalition.

PRESIDING COMMISSIONER MORAN: All right. Hearing no further appearances, I am going to turn to Commissioner Rahbar to administer the oath.

COMMISSIONER RAHBAR: Thank you. To our witnesses, this panel is dependent on you telling us the truth and the law requires you to do that, so I am going to administer the oath. I am going to ask you to introduce yourselves and state your names. Then I am going to -- I really have two questions. I will put the two questions to you, and I will wait for each of you to answer. Thank you. Why don't we start with you?

T. WASIK: Good morning. Tom Wasik.

N. YEATES: Natalie Yeates.

M. VILLETT: Marc Villett.

COMMISSIONER RAHBAR: Thank you very much. So my first question is: Do you solemnly promise this panel that you will tell us the truth, the whole truth and nothing but the truth?

T. WASIK: I do.

N. YEATES: I do.

M. VILLETT: I do.

COMMISSIONER RAHBAR: Thank you. Second

question is: Then do you understand that breaking that promise would be an offence under our law?

T. WASIK: I do.

N. YEATES: I do.

M. VILLETT: I do.

COMMISSIONER RAHBAR: Thank you. Appreciate that.

PRESIDING COMMISSIONER MORAN: Thank you, Commissioner Rahbar. Over to you, Mr. Myers.

J. MYERS: Thank you very much. I will turn it over to our panel to deliver the presentation. We will put that up on the screen for you.

PRESENTATION BY N. YEATES:

Good morning, Mr. Chair, commissioners and everyone attending in person and virtually. As you now know, my name is Natalie Yeates, vice president of regulatory affairs with Alectra Utilities. With me today is our panel, Mr. Wasik and Mr. Villett, who each participated directly in the settlement conference and can speak to areas you may wish to explore.

Alectra has been asked to present a summary of the settlement proposal reached in EB-2025-0252, our 2027 to 2031 custom IR application. The settlement proposal was originally filed on July 30th, an updated version of the settlement proposal, and this presentation was filed on September 11th. Before we begin, we want to acknowledge the work of the

intervenors. As the Board is aware, intervenors must first reach alignment amongst themselves before negotiating with the utility, and they represent very different customer interests and policy positions. Reaching a settlement of this breadth across 11 intervenor groups was a substantial undertaking and we are grateful for their time, their rigor and their good faith. We would also like to thank our settlement conference facilitator for guiding the parties through a complex negotiation.

Our plan this morning is to walk you through the settlement framework, capital, OM&A, the performance scorecard, bill impacts, the new deferral and variance accounts, our commitments and how the annual updates will work. We will expect to take roughly 20 to 30 minutes and then we are available for your questions.

Next slide, please. This slide sets out who is at the table. Alectra and 11 intervenors participated in the settlement conference. The list of intervenors spans the full range of customer interests: Large industrial and commercial consumers through AMPCO, BOMA, and CCMBC, residential and low-income consumers through CCC, VECC and Energy Probe, the institutional sector through OAPPA and School Energy Coalition, and environmental and distributed energy interest through Environmental Defence and the Distributed Resource Coalition. I raise this because

it speaks to the weight the Board can place on the outcome. The reductions and commitments we will walk through were tested by the parties with competing objectives, and the proposal before you is a complete package that balances those interests.

I would note the settlement proposal reflects a complete settlement on all issues. The parties request approval of the settlement proposal as a package, and none of the matters in respect of which a settlement has been reached is severable.

Next slide, please. Turning to the framework itself, the parties have agreed to a custom incentive rate framework built off a full cost of service rebasing in 2027 followed by a formulaic approach for 2028 through 2031. In 2027, there is a complete review of the service revenue requirement and other revenue, which yields the base revenue requirement used to set distribution rates. That is a conventional rebasing year and it anchors everything that follows. For 2028 to 2031, rates escalate by a custom price cap index, which is inflation plus a revenue growth factor. Inflation is the OEB's annually published inflation factor for electricity distributors, so it updates each year with the Board's own published figure.

The revenue growth factor is where incremental funding for capital and operating needs comes from, and it has two components. First, the capital

portion driven by in-service additions, and it is reduced by a 0.15 percent stretch factor and a further 0.15 percent incremental capital stretch factor with a working capital adjustment. The incremental stretch factor reflects the fact that this a custom application with a five-year capital plan, and it builds additional productivity into the capital program that Alectra must manage to. The non-capital portion is OM&A, escalated by inflation and a fixed billing determinant growth factor, offset by other revenue and subject to the same 0.15 percent stretch factor.

Two points worth flagging: First, a forecast of inflation is removed from the revenue growth factor so that the Board's actual published inflation factor can be applied each year, from '28 through to 2031. Second, as this is a custom price cap framework, we would receive incremental revenues during the rate term from billing determinant growth. Therefore, these incremental revenues are removed from the revenue growth factor so that 2028 to '31 revenues increase solely as a result of the custom price cap index. The net effect is a framework that funds the investment our system requires, embeds meaningful productivity requirements and keeps the annual updates transparent and largely mechanistic.

Next slide, please. This slide addresses a feature that is somewhat unique to Alectra: Rate

harmonization across our five legacy rate zones. Annual rate design has two components. The cost of service component is based on 2027 revenue requirement and applies the same way across all rate zones. The harmonization component reflects the movement of five different legacy rates towards a single harmonized set of rates, and the parties agree to phase that in over the full five years.

2027 begins with the 2026 OEB-approved rates in each rate zone, plus the cost of service component, plus one-fifth of the harmonization component. From 2028 onward, the prior year's rate is escalated by the custom price cap index and then the next one-fifth of the harmonization component is added, which is also escalated by the index. By 2031, all five rate zones arrive at the same harmonized end-state rate. The reason for the five-year phase-in is customer impact mitigation, and spreading it over five equal tranches keeps the annual movement gradual and predictable.

I would now like to pass it over to my colleague, Mr. Wasik.

T. WASIK: Next slide, please. Before turning to the numbers, some brief context on what this settlement funds. Alectra serves more than 1 million customers across our service territory, making this the largest municipally owned electric utility in Canada by total customers served. Alectra operates a

large, non-contiguous and complex service territory of 1,912 square kilometres. It includes multiple geographies, degrees of urbanization and vintages of distribution assets.

The system itself comprises 149 municipal stations, over 128,000 distribution transformers, roughly 23,700 kilometres of underground cable and 18,500 kilometres of overhead wire, more than 134,000 poles and over 6,600 primary switches.

The point I would leave with you is one of scale and of mix. We serve dense urban centres and lower density areas within a single utility. We have a significant amount of deteriorated infrastructure requiring renewal, and we are seeing substantial growth pressures across the territory including housing and commercial development, transit and fleet electrification and large-load connection requests. This is the backdrop against which the parties negotiated the reductions I will now describe, and it is why the five-year capital forecast was so important to Alectra in this settlement.

Next slide, please. With respect to capital, which was among the most heavily negotiated elements of the settlement, on in-service additions, the settled five-year figure is $2,358.5 million on a net basis, which reflects a reduction of $416.3 million, or 15 percent, compared to what we applied for.

On a capital expenditure, the settled five-year

figure is $2,715.4 million net, which reflects a reduction of $418.8 million, or 13 percent, compared to what we applied for.

The settlement on capital focused on in-service additions as these investments correlate the bill impacts, the capital expenditure portfolio is higher than the in-service portfolio as it includes multiyear capital projects which are planned to be started, but not completed, by 2031. The bottom-up review identified specific projects and programs to reduce in-service additions, and those same investments were also removed from the capital expenditure schedules. As such, removing the same projects from each schedule results in a slightly different percentage of reductions, a 15 percent for in-service additions and 13 percent for capital expenditures.

The tables break those reductions down by investment category. The largest reduction in both dollars and percentage terms is in system renewal, down $285.1 million or 21 percent of in-service additions. System access is reduced by 5 percent, system service by 12 percent and general plant by 18 percent. The reductions by investment category were determined by Alectra. The settlement reflects the party's agreement on the overall envelope reduction on an in-service basis.

How do we manage a reduction of this magnitude?

Alectra applies a comprehensive asset management planning process which is well established and which appropriately balances the needs and preferences of customers, distribution system requirements and relevant public policy objectives. This detailed bottom-up process optimizes the capital portfolio based on consideration of the value, risk, pacing and sequencing of capital investments.

Alectra executes the capital work through prioritization, adjusting the schedule and timing of projects, leveraging procurement and supply chain strategies and continued labour and process efficiencies.

We will track and document variances against the plan through the term so that at our next rebasing, the Board and the parties will have a clear and complete record of what we spent.

Next slide, please.

The custom performance scorecard is the accountability mechanism attached to this framework, and it is what allows the Board to have the confidence that the settled funding will deliver tangible outcomes for customers. The settled targets in the scorecard were updated based on the agreed-upon capital reductions. For clarity, the intervenors did not review or approve the specific targets but accepted that we revise the target based on the reduction in the capital plan.

The scorecard commits Alectra to measurable targets across five reporting categories: Reliability, cost control, infrastructure renewal, automation, and meeting capacity needs. On reliability, the settled SAIDI target by 2031 is 0.878 hours, excluding major event days and loss of supply. I would note that the settled target equals the OEB's own reliability performance improvement target, so are being held to the Board standard. The failed equipment customer hours interrupted target settled at 434,239 hours.

On cost control, we commit to delivering planned capital within plus or minus 5 percent of the plan and, to fleet availability, above 85 percent.

On infrastructure renewal, the targets are volumetric and specific: 4,447 poles, 3,882 transformers, 150 switches, 300 switch gear units, and 307 kilometres of cable.

I will draw the Board's attention to AMI2.0, where the target of 950,000 meters installed is unchanged from what we proposed. That commitment was preserved in full through the settlement.

On automation, the settled annual targets are 85, 55, 75, 90, and 90 devices across 2027 to 2031, and on capacity, 625 MVA of added station capacity.

I will now pass on to Marc Villett.

M. VILLETT: Thank you. Next slide.

So overall, the settlement agreement reduces our

OM&A by $142.8 million over the '27 to '31 period, representing a 7.4 percent reduction compared to our filed application. For the 2027 test year, the settlement agreement includes $334.8 million in OM&A, which represents a $17.6 million reduction or 5 percent compared to the filed application.

Over the '28 to '31 period, OM&A will be escalated using an index-based approach rather than annual forecasts. The index includes the OEB inflation factor plus a five-year fixed billing determinant growth factor of 0.86 percent compared to the 2.17 percent growth factor proposed in our filed application.

Under the settlement agreement, any cost escalations above the approved index remain Alectra's responsibility. At the same time, the company will be expected to operate within a lower OM&A envelope while continuing to deliver a larger capital program and support growth across the system.

Successfully meeting these expectations will require sustained productivity gains, efficient use of resources and strong operational execution throughout the planned period.

And now I will turn it back to my colleague, Ms. Yeates.

N. YEATES: Thank you. Next slide, please.

This slide shows how the parties sequenced customer impacts over the term, which is the rate-

smoothing mechanism of the settlement. There are two levers: The first is the timing of the deferral and variance account disposition; the second is the five-year harmonization of base distribution rates.

Group 1 DVA balances are disposed of in 2027 in the ordinary course. For Group 2, the parties agree to different disposition periods by rate zone, recognizing that the balances and the resulting customer impacts differ across the five zones.

The Group 2 balances for the Enersource, Horizon and Powerstream rate zones are disposed of over the 2027 to '31 period. For the Brampton rate zone over the 2028 to '31 period, and for the Guelph rate zone over the 2029 to '31 period, in order to mitigate the 2029 rate impact resulting from the expiry of the Guelph rate zone specific price cap adjustment rate riders.

Layered over that, the harmonization of base distribution rates runs across the full 2027 to '31 window in the five equal tranches we discussed earlier.

The design objective was to smooth rate impacts. Staggering the disposition periods by rate zone is what allows the overall bill impacts to land where they do, which I will turn to now.

Next slide, please.

This slide shows the 2027 impact on the distribution portion of the bill, both proposed and

settled by rate zone and customer class. Three things drive the change: Rate harmonization, which differs by rate zone because each zone starts from a different legacy rate.

Two, cost of service, which is the same across all rate zones because it flows from a single 2027 revenue requirement, and three, Group 2 DVA disposition, which again differs by rate zone based on legacy Group 2 DVA balances.

Over the five-year period based on the settlement proposal, the five-year average annual increase in the distribution portion of the bill is approximately 5 percent.

Because harmonization moves each rate zone toward a common end state over five years, and because of the different Group 2 disposition periods, the rate impacts by rate zone will differ each year.

The rate class impacts for every rate zone are further detailed in the settlement proposal. Next slide, please.

This slide places those distribution impacts in the context of the customer's total bill. The distribution portion is one component of the bill alongside commodity transmission, regulatory charges and the HST. As a result, the movement a customer actually experiences is more moderate than the distribution-only figures on the prior slide.

Based on the settlement proposal, the five-year

annual average increase in the total bill is approximately 1 percent. Against a period in which Alectra is renewing a significant volume of deteriorated infrastructure, connecting new load, completing the AMI 2.0 deployment, and harmonizing five legacy rate structures into one, the parties have arrived at an outcome of roughly 1 percent per year on the total bill. In our view, that is a reasonable balance between the investment the system requires and what customers can be asked to pay.

Next slide please.

Turning to the new deferral and variance accounts agreed to by the parties, the settlement establishes four deferral and variance accounts for the term, each designed to either protect customers or enable a program.

The capital-related revenue requirement variance account is a customer protection mechanism; if we underspend, the money goes back to ratepayers.

The non-wires solution deferral account funds the non-wires solution program, capturing the OM&A and incentive costs to acquire DERs.

The earning sharing mechanism account splits earnings above 150 basis points deadband, 50-50 with customers, though asymmetrically. So customers only share the upside.

And lastly, the incremental cloud computing account lets us record incremental cloud computing

costs, offset by the on-premise capital for two specific projects which have been identified in the settlement proposal. Next slide, please.

Section D of the settlement proposal sets out the studies, reports, and other commitments that Alectra has agreed to undertake over the rate term. I do not propose to go through each one, but I am happy to address any that are of particular interest to the panel. Speaking to them collectively, these commitments cover studies and specific operational and planning commitments, and they will inform the evidence we bring forward at our next rebasing.

On DER connections, we committed to track and report connection performance, examine ways to reduce connection restrictions and install AMI 2.0 meters where bi-directional capability is needed.

On EV charging and pilot projects, we will separately track commercial and multi-unit charging, and publish results from our fleet and vehicle to everything pilots.

On non-wires solutions and markets, we will deliver DER and grid modernization projects, and develop a non-wires solution market framework with stakeholders.

And on planning and customers, we will develop a distribution losses guideline, model energy transition scenarios and promote ultra-low overnight rates. Finally, on the next slide please. Thank

you.

This slide presents the key elements of our annual update applications for 2028 through 2031. Our expectation is that these are largely mechanistic exercises. Every input that determines rates in those years has been determined in this proceeding, and is set out in the settlement proposal, with the exception of the OEB's annually published inflation factor.

Each year, we will apply the custom price cap index, which will be updated for the OEB's inflation factor and add the next one-fifth of the harmonization component. We will also dispose of Group 1 DVA balances, along with the usual generic updates such as transmission rates.

Because the models and the detailed revenue requirement calculations have been filed as part of this settlement, annual update applications will include limited updates. In our view, that supports an efficient review process, and it is the kind of application that the Board has previously found appropriate for determination by a delegated authority.

That concludes our presentation.

Let me close by returning to where I started. This outcome reflects a great deal of work by the intervenors and our own team, and it represents a genuine balance between the investment Alectra's

system requires and the affordability of customers' bills. It is the view of the parties that the settlement proposal results in rates that are just and reasonable, and we therefore request that the panel approve the settlement proposal.

We would be pleased to answer any questions you may have on any element of the settlement proposal. Thank you.

PRESIDING COMMISSIONER MORAN: Thank you, witnesses.

Commissioner Sword, you have some questions?

COMMISSIONER SWORD: Thank you.

Mr. Lim, I understand you have carriage of the presentations?

H. LIM: I do.

COMMISSIONER SWORD: Would you mind turning to -- it was part of the application, October 14th, 2025, the original application. I have it as page 305 of 1738. And what you will see is a map of the service area.

H. LIM: One moment.

COMMISSIONER SWORD: Sure.

H. LIM: Sorry, 1738?

COMMISSIONER SWORD: Page 305, as that appeared. I skipped a tab in the schedule, but just for ease of -- I hope for ease of retrieval.

J. MYERS: Perhaps you can provide us with the exhibit tab and schedule reference.

COMMISSIONER SWORD: Just one of your service area will be fine, any map that you were able to retrieve. That was one in particular.

H. LIM: The one in the presentation will suffice?

COMMISSIONER SWORD: Sure. That's fine.

J. MYERS: So slide 5 from the presentation.

H. LIM: I will share the screen.

COMMISSIONER SWORD: I will begin perhaps with a question to one of your panel members; I am not sure who or which. The rates of all the service area were deemed at one point in time to be the cost of serving only that area in which you lived. Correct?

N. YEATES: That is correct.

COMMISSIONER SWORD: Yeah, cost causality and that. I realize when you are looking at what new rates to implement, you probably had many options at your disposal. You chose the one, rate harmonization across the entire area on that. So cost causality for the individual community may not have been -- that's no longer in play?

N. YEATES: So what we did, and a key element of this rebasing application was putting forward a consolidated distribution plan. So that five-year DSP considers the needs of our service territory as a whole. So planning was done on Alectra-wide basis and not on a legacy utility or service territory basis when we put forward the plans in this

application. And to align with that, our proposal in this application is to move from five sets of legacy rates to an Alectra-wide harmonized rate that aligns with that Alectra-wide view of our planning process.

COMMISSIONER SWORD: Okay. And in doing so there -- because you have indicated some of your -- you have indicated, and I accept that -- a really wide diverse area of which you serve on that and all harmonized together under one rate?

N. YEATES: Correct.

COMMISSIONER SWORD: Okay. There was some particular ones related to that. In the -- I understand some Horizon utility rates will be grandfathered. Certain ones will be. What's the -- they are called legacy. What's the legacy behind that?

N. YEATES: So the rates for the Horizon rate zone large use dedicated asset class will be grandfathered. Those customers were identified in that class for a specific reason based on an application put forward by legacy Horizon. In Alectra's view, all our large use customers are going to be part of Alectra's large use class. And so, we have decided as part of this, and we have proposed as part of this application, to grandfather the few customers that are in the large use dedicated asset class for legacy Horizon.

COMMISSIONER SWORD: Okay. And were there any

ones outside the other area that would have liked to enjoy or would have been able -- or eligible to enjoy something similar in their own service area?

N. YEATES: So in putting forward the -- developing the evidence for the application, we actually did a review and assessment of all the large use customers to determine, at that time, whether any of them would have been eligible for that large use dedicated asset class and they were not.

COMMISSIONER SWORD: Okay. Thank you. In the Guelph rate zone, customers are going to enjoy a $4 million refund or a credit. Where does that credit come from?

N. YEATES: So that credit is going to be funded by the shareholder, and the intent of that is to preserve Guelph's full 10-year rebasing deferral period. So Alectra merged with Guelph in 2019 and we are rebasing the Guelph rate zone two years early, but to preserve that 10-year rebasing deferral period customers in the Guelph rate zone will receive that credit in both 2027 and 2028.

COMMISSIONER SWORD: With shareholders shouldering accountability for that cost?

N. YEATES: Correct.

COMMISSIONER SWORD: Okay. On or about 2019, Brampton became part of the service area. Correct?

N. YEATES: Brampton was part of the original merger in 2017.

COMMISSIONER SWORD: Okay. Sorry, I got the date wrong. All right. In terms of the rate mitigation specifically, you have got a DVA you are going to apply to it. Correct?

N. YEATES: So with respect to rate mitigation, the rate mitigation is with respect to the disposition periods of the Group 2 deferral and variance accounts.

COMMISSIONER SWORD: Yeah, and one of them is specified specifically to Brampton to compensate for some of the rate impact that they would have as well. Correct?

N. YEATES: No, there is no specific rate mitigation, rate rider for Brampton. What we are doing in the Brampton rate zone is we are starting the disposition of the Group 2 balances in 2028 instead of 2027.

COMMISSIONER SWORD: Sure, but correct me if I am wrong, does that particularly apply in terms of rate mitigation for the Brampton rate zone?

N. YEATES: So it's rate mitigation in the sense that the Brampton rate zone has a higher rate impact in 2027. So to avoid additional rate impacts from the disposition of their Group 2 balances, which is a recovery from the Brampton rate zone customers, we are starting that recovery one year later in order to help smooth the rate impacts year over year.

COMMISSIONER SWORD: Okay. Brampton seemed to

enjoy a lower base rate, a legacy rate. Does that -- is that a fair statement?

N. YEATES: So for residential customers, the Brampton and Enersource rate zones had the lowest residential rates, with the Guelph rate zone having the highest residential rate.

COMMISSIONER SWORD: And so, to help with that transition, what would be the -- because it's hard to speculate, but I am just struck as to how low they seem to be compared to the other shoulder -- neighbouring utilities.

N. YEATES: Brampton's, if I have a good -- the Brampton rate zone residential rate was very similar to the Enersource rate zone, Mississauga/Brampton rate. They were very similar, so the impact of rate harmonization in those two rate zones, because those rates were lower, they have an unfavourable impact -- slightly unfavourable rate impact from rate harmonization.

COMMISSIONER SWORD: Okay. Thank you. There are some -- just questions not related to rate harmonization. On that, I just note, Power Workers' Union didn't play -- they were neither here nor there. They participated, but didn't render any decision either way?

N. YEATES: That is correct.

COMMISSIONER SWORD: Okay. Thank you. You have a cloud computing account in that in terms of your --

where does the specific location of the hardware reside? Is it domestic? You can come to that later.

J. MYERS: I just want to make sure that that's not a sensitive topic that we should keep off the public record. Maybe I will refer that to the panel to consider.

COMMISSIONER SWORD: Okay.

N. YEATES: I don't think anyone on the panel has that information at this time.

COMMISSIONER SWORD: Fair enough. Perhaps on a best-efforts basis, if you could follow up on that, please?

J. MYERS: Sorry, could you just clarify exactly what you are looking for in that question?

COMMISSIONER SWORD: You have cloud computing and that's more of a topical discussion in this current era on that. Where does the actual hardware reside? Is it in your service area and under your care and control, things of that nature?

J. MYERS: Okay. Thank you.

N. YEATES: Hi, sorry. I just wanted to be helpful, to help close that one out, if I may. So for those two projects that fall within that cloud computing account, we haven't actually selected the solution. We still have to determine whether it's going to be an on-premise solution or a cloud-based solution, but that work has not yet begun to determine what the solution is.

COMMISSIONER SWORD: The best kind of undertaking; it has just been solved. Thank you. I note you have customer surveys, and you can really get to know who your customers are through that one. It was visibly apparent. Just one small thing that I noticed: In terms of all the technology you have and been employing, the call centre calls seem to be being extended. Any thoughts or explanation as to why that might be?

N. YEATES: So are you -- is there a reference in the evidence that you're looking at with respect to the call centre call volumes?

COMMISSIONER SWORD: I was, but it was the call volumes in terms of the time people were spending on the telephone with your call centre people. Just as an observation, it seemed to be increasing with all the available tools. I have searched your website. It's quite interactive and people seem to be seeking more of a verbal information exchange with you.

N. YEATES: So I am aware that part of the reason for that is that, you know, customers are calling in sometimes with more complex questions, customers that may have electric vehicles and wanting to connect with the utility, and as customers in our service territory adopt new technology, some of those calls become more complex that our call centre representatives have to respond to.

COMMISSIONER SWORD: Sure, okay. I am aware

this is an interaction between us and we get your presentation, but there is other things that just come up that we may know more during a hearing, so it was interesting.

You have -- I am not quarrelling about the disposition of it, or questioning rather, Energy East consultation costs on that. That's a legacy issue. The Energy East was a project that was cancelled, I think, in the year 2017. I was -- what was the origin of that DVA? And if you don't have the information now, a follow-up will be fine.

N. YEATES: I don't have the details on that right now. I know that the amount would have been, I believe, immaterial but really tied to one of the legacy rate zones. You can appreciate we are disposing of these Group 2 balances going back, you know.

COMMISSIONER SWORD: That falls into the bucket of I was just curious about the origin of it. And that is where I --

N. YEATES: Yes, for sure -- okay. I can find out.

COMMISSIONER SWORD: Thank you. All right.

Commissioner Moran?

PRESIDING COMMISSIONER MORAN: Ms. Dhillon, can we get an undertaking number for that, please.

R. DHILLON: I will mark that as undertaking JP-1.1.

UNDERTAKING JP-1.1: ANSWER WHAT GAVE RISE TO THE ENERGY EAST CONSULTATION COST DVA.

PRESIDING COMMISSIONER MORAN: Commissioner Rahbar, you have some questions?

J. MYERS: Sorry, just before we move on, can we clarify exactly what the undertaking is?

COMMISSIONER SWORD: Well, I will clarify the question and the undertaking can result from that. There is an Energy East consultation cost on that. I was just curious as to what gave rise to that DVA initially, and it's more for information purposes but I was just curious about the connection between an electric utility and the Energy East consultation cost.

J. MYERS: Okay. So the underlying purposes for that DVA?

COMMISSIONER SWORD: Yes, which gave rise to it.

J. MYERS: Okay.

COMMISSIONER SWORD: Thank you.

COMMISSIONER RAHBAR: Thank you. Maybe just a brief question. So you've elected to harmonize across geographically diverse area, perhaps with underlying cost structures to actually serve, which I understand. There should be a commensurate reduction in administrative burden if you kind of migrate from five legacy zones to a single one. We are not seeing that, of course, in this application. Is this something that one should be expecting at your next

rebasing, to see a dramatic drop in administrative costs moving from five legacy rate zones to a single one?

N. YEATES: So with respect to the implementation of these rates, I will first speak to the '27 to '31 period. Because we are phasing in the harmonization over the five years, from a billing system standpoint, we are still maintaining five rate structures in our billing system in order to facilitate the billing of these rates. And I think what you're asking now is, in this next application once we get to those harmonized rate, would there be administrative cost and savings? I think that is something we definitely have to assess as we put forward the next rebasing application and look at the systems that we have in place at that time.

COMMISSIONER RAHBAR: So just for clarification, if reduction in administrative costs isn't the objective, then with such a diverse geographic area, presumably with underlining different cost structures, did you -- how did you arrive at the single rate zone? I mean, I assumed that a single rate zone is desirable because ultimately, it's administratively more efficient. I understand that in the first tranche we are not seeing that because you're maintaining the five rate zones, but if not administrative efficiency, what would be the rationale for moving away from underlying cost

structures to serve?

N. YEATES: So what I would say is we are moving towards an Alectra-wide cost structure, and the operating and capital costs underpinning our five-year plan was done on an Alectra-wide basis. So if I look at operating costs for Alectra, it's not broken down for each legacy utility, but it's considered in the context of the needs of the organization as a whole. So that's the primary driver for moving towards a harmonized rate, in that our planning internally is done on Alectra-wide basis, and therefore, the rates are going to also be -- our proposal, of course, is to get to one Alectra rate so that all residential customers across our service territory are paying the same residential rate.

COMMISSIONER RAHBAR: Thank you. That's helpful.

Moving from five different capital structures and projections to a single one presumably results in some process efficiency. I guess my question is: Where, if anywhere, are we seeing that process efficiency reflected in this application? And if not in this one, could we look forward to seeing it when the harmonization is done?

T. WASIK: So in terms of approaching sort of the capital investments in a single manner, that takes into account all of the different geographical areas in our service area. One of the things that we

strive to is to deliver the same high performance across all of our service areas. So whether it's a small little town or it's a large urban area, we strive to deliver the same performance the same modernization the same technology the same resiliency to storms. And so, where those efficiencies and those benefits appear to our customers is through improved reliability practices, leveraging common modern technologies and emerging technologies into all of our -- for all of our customers. And so, we create the performance with respect to using these technologies across all of our service areas consistently providing customers with capacity, reliability, safety, and security of supply.

So that's the premise around having, you know, a uniformed and consistent plan for all of our service areas is to deliver that same performance target to all of our customers.

COMMISSIONER RAHBAR: Again for clarification, so five legacy rate zones, they would have had different reliabilities and different rates of modernization, and you're bringing them to the same level. Do you have it handy as to which were the ones that were the least modern and which of your rate zones were closer to the target that you're aiming for?

T. WASIK: I can provide an example. So one of our rate zones was more mature in terms of automation

of the grid, and we were able to resolve specific outage events rather quickly, especially during storms. One of our other areas, the Hamilton rate zone, wasn't as advanced in terms of grid modernization. So over the last few years -- and it's going to continue into this rate period -- we have significantly invested in bringing that rate zone up to present day standards with respect to grid automation, and those customers have seen a significant improvement in reliability because of that technology. And so, there's the field component around it, but there's also the back office component around it that requires the control room to be able to automate the grid. So that would be one example.

Each area had different areas of focuses, and so, this allows us to pick the best solution to remedy those elements, but that automation example is a really good one to demonstrate the benefit of a uniform and a consistent plan across all of our service areas.

COMMISSIONER RAHBAR: Thank you.

PRESIDING COMMISSIONER MORAN: Thank you, Commissioner Rahbar. I have a few questions as well.

I just want to follow up on an answer that you gave to Commissioner Sword with respect to Brampton and Mississauga, the basic regulatory principle being that, you know, customers pay for what it costs to serve them. And help me -- correct me if I have this

wrong, but I think your answer to Commissioner Sword was that the impact to those communities, Brampton and Mississauga, is not so much from an increase in how much it costs to serve those communities as much as it is from the cost that results from harmonization.

So did I understand your answer correctly?

N. YEATES: What we were able to do is when we developed the 2027 distribution rates, it flowed from our 2027 revenue requirement. And then what we were able to do as an additional step is to compare the 2026 OEB-approved rates to the 2027 rate, and what was important for us is to identify that increase, to identify the drivers for that increase. And we knew that there were two. One was the impact of harmonization across the rate zone and then, two, the impact of cost of service.

So yes, there's two components that drive the rate increase in every rate zone, and it's the harmonizing to one rate and then the impact of cost of service itself.

PRESIDING COMMISSIONER MORAN: So focusing on the impact from harmonization, you know, on what basis would you justify to the ratepayers in Brampton and Mississauga that they are going to end up paying higher rates because of harmonization, which is resulting from Alectra' interest in having an Alectra-wide approach of things? On what basis, you

know, could you say to those ratepayers that, you know, you're still getting a benefit from that that justifies that cost driver?

N. YEATES: So our customers across our rate zones since the merger have been benefitting from the merger through lower rates and rates that were adjusted over that ten-year rebasing deferral period by price cap adjustments and the underlying costs for those legacy utilities for those cost of service applications are materially different than they are now. So what we are doing now is really resetting rates and aligning the rates with the costs to actually serve customers across our five rate zones.

So what I would say is that the rates that the customers are paying in each of our rate zones are actually costs that more closely align with the cost to serve those customers as Alectra Utilities.

PRESIDING COMMISSIONER MORAN: Okay. No, I think I understand that, that you said there with two cost drivers. One is the one that you just described now, but then there's this additional cost driver with respect to harmonization.

I am interested in how you justify the additional costs associated with harmonization in Brampton and Mississauga. On what basis would you say to those ratepayers that, yes, on the costs to serve you, that cost has gone up and that's reflected in your rate increase, but there is also a component

of your rate increase that serves harmonization. What's the benefit that flows to those customers with respect to the impact from harmonization? Granted that there is an impact associated with the increases of cost to serve but the extra costs.

N. YEATES: The impact from harmonization depending on the rate zone, depending on the rate class is either favourable or unfavourable impact. For the Guelph residential customers, it's a very favourable impact from harmonizing, and for Brampton and Enersource, it's a slightly unfavourable impact just on harmonization impact, but what I would say is that any type of change in the rate to get to a harmonized rate, you have to look at the fact that these customers in the legacy rate zones were paying lower rates for quite a bit of time and now we are, you know, aligning those rates with the costs.

PRESIDING COMMISSIONER MORAN: Right, but I guess let me just take one more attempt at this. What's the benefit to those to now paying that higher rate associated with the impact of harmonization? I think it's straightforward to explaining why the impact associated with an increased cost of service is increasing your rates but what is the benefit to those ratepayers from the impact from harmonization?

N. YEATES: So one of the key benefits of moving to a harmonized rate is for customers, that all customers across our service territory is going to

pay the same rate. It reduces customer confusion as to, like, why a residential customer in one rate zone is paying one rate versus the other, and it sends the message that this is truly an Alectra-like plan, and the service that we are providing to each of the customers across our service territory is the same.

PRESIDING COMMISSIONER MORAN: Okay. I will move on to standby rates, and -- which raise the principle of if you're in a class of ratepayers, you should pay the same rate as everyone else in the class. But as I understand it for standby rates, you have a class of ratepayers where there's a legacy group that pays 100 percent of a cost whereas new entries to that rate class are only paying 50 percent of the cost. So I wanted to understand how that works.

And I read the answer to the question in the response to Procedural Order No. 3, but I am not sure I quite understand your answer and how it's justified to charge two people in the same rate class a different rate.

N. YEATES: So with respect to our response to, I believe, clarification question No. 9, so our proposal for the existing customers to continue to pay 100 percent of the rate, the rationale behind that is because those customers when we did their economic evaluation model, the key input used to determine the revenue forecasts in that economic

evaluation model was a distribution volumetric rate that was 100 percent and not a 50 percent rate, and therefore, the resulting calculation or determination of the customer contribution was based on that revenue forecast.

So if we now charge those customers a different rate now, say, the 50 percent of the volumetric rate, then as a utility, we will be losing on revenues and not kept whole because the inputs that we use for the economic calculation would be materially different than the actual billing that's happening for these customers.

PRESIDING COMMISSIONER MORAN: Okay. So let me see if I understand that. Legacy customer comes along. They want standby -- a standby rate which requires some infrastructure support, And you do a discounted cash flow calculation that says this is the standby rate. So at 100 percent, I am going to use that as my revenue stream against the cost to provide that service to you, and the difference is what that customer is going to contribute and then they pay the rate. Right?

N. YEATES: Correct.

PRESIDING COMMISSIONER MORAN: Okay. Flash-forward then, post-legacy date, I come along and I am exactly in the same position. I want exactly the same thing, but you are proposing to charge me a different rate. So your revenue stream that you are

counting in your DCF is now 50 percent, not 100 percent. So based on that, if there's a customer contribution that gets kicked in, does that suggest that the customer contribution will be larger for those because you have less revenue to offset?

N. YEATES: Yes.

PRESIDING COMMISSIONER MORAN: So that's the basis on which you would say it's pretty much even Steven, going forward.

N. YEATES: Correct.

PRESIDING COMMISSIONER MORAN: Because the new customer is paying more upfront and pay less over time, and the old customers pay less upfront and more over time, but on the total cost basis, it is pretty much the same.

N. YEATES: That's correct.

PRESIDING COMMISSIONER MORAN: Okay. I got it. Thanks.

All right.

The next question I have is with respect to the non-wires solution deferral account. Again, as I understand it, the Ontario Energy Board has been -- as a policy initiative, has been promoting the use of non-wires solution as a way of avoiding or deferring the need for new infrastructure. And so, from my perspective, when I look at a deferral account, I am trying to understand what you need the deferral account for.

It seems to me that if you have a non-wires solution that defers or avoids the need for new infrastructure, and you're operating in an IRM PBR period, you have more room in your capital envelope. And so, why do you need to put some money into this account for recovery later, given that you freed up capital? Or maybe it's because that freed-up capital is going to be recorded and given back to the ratepayers? Help me understand how this is posed here because I am trying to understand why it's justified.

T. WASIK: Thank you for the question, Commissioner Moran. The premise behind the deferral account for the non-wires solution is because this is an emerging market for us. We are not quite sure what the price that we will be able to procure these non-wires solution services will be, and we are also working through setting up the necessary administration of how to be able to dispatch or procure these particular services for the projects we have identified.

And so, because the market rate hasn't been set and we will be issuing that very soon, we have an uncertainty in terms of what the final costs are going to be. And so, we have asked to defer those costs, and then when the final costs come in, we will present the entire case.

And so, the OEB has prescribed a BCA framework

upon which to calculate the economics of these non-wires solutions, and so we don't have all of those inputs. When we do go to the market and find out what the price those services that we will be able to procure them is, we will then be able to finalize and come in with final costs knowing with certainty what the economic value of these solutions will be.

PRESIDING COMMISSIONER MORAN: Right. And as I understand it, the screening process is to determine that there is economic value for those, and that would be reflected in, you know, how you deploy capital.

So again, I am just trying to understand why there's a need to have a deferral account, given that these projects won't go ahead unless they are economic to begin with, and pass the screening test and do actually defer or avoid infrastructure construction.

Life is full of risk, right, and that's why you get a risk premium on your return. So I am trying to understand why this is particularly important and, more importantly, I am trying to understand why it's even needed.

T. WASIK: We felt that this is the most fair approach for our ratepayers, to be able to gather all of the necessary market costs and bring back those particular costs for a proper review when we want to dispose of the variance account or deferral account.

So we felt that it was the most appropriate way to proceed with this new emerging technology, gather the necessary inputs, and then once the final costs are in, then be able to demonstrate the prudence of procuring these services for these needs.

PRESIDING COMMISSIONER MORAN: All right. So when you have all of that data and it also -- because it's passed the screening, it demonstrates that you have been able to avoid or defer capital, are you going to reflect the value of that capital in this account as a way of helping ratepayers share in the benefit of the non-wires solution?

T. WASIK: My understanding is that the value of the deferred capital is included in the BCA calculation. So yes, it will be reflected in that amount.

PRESIDING COMMISSIONER MORAN: Okay, thank you.

The last area that I want to explore with you is the -- I guess it's what I would call the opening rate base question. And that was, I think, addressed in Question 1 in Procedural Order No. 3, where you indicated that there would be a significant amount of work to answer the question, but maybe the information was already available in IR-JT-1.1.7.

I guess the -- as I am trying to understand it, one of the concerns that was expressed in declining to give the information was that you wanted to avoid having two sets of books. We didn't indicate what we

were going to do with that information, so I get that there might be a concern down the road depending what we did with it.

But let's back this up to the principle, which is, you know, you're -- you pointed to the fact that under the IFRS system, you were kind of required to start recording things in a particular way when you got the asset life study results back a couple of years ago, but I am assuming you are not saying that just because IFRS requires you to do things in a particular way, that that binds our hands with respect to rate-making principles. I am assuming you are not saying that, suggesting that IFRS gets to decides what is recovered rates and not the OEB?

M. VILLETT: No, we are not saying that would bind the panel, but I think as we pointed out in our response to Item 1 and in 2-Staff-153, we do have only one fixed asset, a subledger and one GL. And according to the OEB's policy under the accounting procedures handbook, as we have indicated here, the Board expects that the capital assets for regulatory reporting to be presented on the same basis as the general purpose financial statements.

So I think later on in that response, we have also just indicated there would be additional administrative cost to set up two separate fixed asset systems, two ledgers. There would be additional reconciliations required, so we are not

suggesting that it binds the panel, but I wanted to point out that this will create a permanent difference and it's not a small -- it's not a small undertaking, there's over 30,000 assets that we have that would have different cost bases. We would have to have different -- two sets of work orders as well.

So if we do make this change, it really can't be reversed.

PRESIDING COMMISSIONER MORAN: Right. And it's not unusual, generally, that, you know, there can be two sets of books for a utility, and there is the regulatory books, and there is the financial accounting books. I mean, that does happen from time to time, does it not?

M. VILLETT: It does. It does happen, but typically, I haven't seen it happen with a fixed asset subledger. It's typically with the regulatory accounts that are separate versus -- because IFRS at this point doesn't have regulatory accounts, so you can still manage that within one ledger. But when we talk about setting up two separate fixed asset subledgers, that's a significant undertaking, which as I said, we have got 30,000 assets. We are talking about duplicating all the records on a permanent basis. Some of these assets, as you know, have lives of over 50 years. So when you have those different rate bases and different -- from IFRS versus regulatory, different depreciation, that's going to

be differences for more than 50 years that will never get reconciled once you make that decision.

PRESIDING COMMISSIONER MORAN: Okay. So I think I understand that you're saying. There is a fair bit of work if one was required to make some changes to how rate base is managed, and if there's two classes of rate base going forward, what would that look like?

So leaving that aside for a moment, let me frame it this way: If I go to the bank to negotiate a mortgage, I have got a principal amount that I have to pay back, and I have to pay it back at an interest rate, and then it's amortized over a period of time. So if it's amortized over 25 years, my total cost of borrowing is going to be x; right? And if it's amortized over 30 years, my total cost is going to be higher, right, because the principal is being paid more slowly and I am paying interest on a balance that's declining more slowly, right?

M. VILLETT: In your example, yes, you would be paying interest over a long term.

PRESIDING COMMISSIONER MORAN: Right. And if I amortized 20 years instead of 25 my borrowing cost would be less. So using that analogy here, you know, you had rates that were based on a particular depreciation schedule during the course of the IRM periods, you did a study that said that this particular set of assets, you know, that we have been

assuming had this kind of useful life now have a longer useful life. So the total cost now, with respect to recovering the depreciation expense and the return, is now going to be higher as a result because you've extended the life, right? Similarly, as my mortgage when it's amortized over a longer period, it's going to cost me moreover time, right? That's fair to say, isn't it?

M. VILLETT: So I think you are saying that the rate base is going to stay at a higher rate for a longer period, and you would return on that higher rate --

PRESIDING COMMISSIONER MORAN: Well, it's going to be depreciated more slowly and earning a return for a longer period time so the total cost to the ratepayer would be higher, you know, because of that longer life just like the total cost to me as a borrower over a longer amortization period given the same principle, right?

M. VILLETT: All right. I understand the principle of what you're saying, but you're also -- yeah, I understand the principle, what you're getting at.

PRESIDING COMMISSIONER MORAN: Yeah. So given your understanding, you would agree that as a ratepayer with the longer asset lives, I am ultimately exposed to an overall total cost that's larger, right?

N. YEATES: I just wanted to add, one of the reasons why we are proposing to refund customers these impacts through the rate riders is because in 2025 and 2026, those two years in which we implemented the change in our fixed asset subledger, the underlying rates -- the rates that customers are paying in those two years are essentially higher than what they otherwise would be. So therefore, in those -- what we are doing here is trying to ensure that customers remain whole and are refunded in 2027 the impact of those changes in 2025 and 2026.

PRESIDING COMMISSIONER MORAN: Okay. I think I understand that and I want to get back to that in a minute. But I want to finish getting an answer to my question, the total cost --

M. VILLETT: I think you are going to earn a return over a longer period, but I think you'd also have to consider, you know, time value of money as well and the fact we are proposing to give a refund back to customers of, you know, $50.6 million between the useful life and DLC accounts. So again, I don't know if I can do those calculation on the fly in terms of the time value of money I think you would have to consider that as well if you are extending the rate base.

PRESIDING COMMISSIONER MORAN: Right. Well, the time value of money would apply equally to my mortgage being amortized over a longer period of

time, as well, so apples to apples is still there.

So if the total cost is going, goes up as a result of opening rate base for 2027 being higher, let me just sort of back up, as a result of the accounting change that you made in 2025, the impact of applying that accounting change in 2025 and 2026 was the result would be that the opening rate base would be higher than it otherwise would have been if the rate base had been continued to be depreciated at the rate that it had originally been depreciated, that's correct; right?

M. VILLETT: Yes, that's correct.

PRESIDING COMMISSIONER MORAN: And with respect to the rebate that you're talking about, it only refunds the difference between the two depreciation schedules that resulted from that change; right? It doesn't rebate the overall impact of a higher opening rate base over the life of those assets, it's just limited to the two years with respect to the change in the depreciation amount; right?

M. VILLETT: Yes.

PRESIDING COMMISSIONER MORAN: Okay. That amount that's going to be rebated, are you proposing --

J. MYERS: Sorry, Commissioner Moran. Ms. Long has something to contribute to this.

MS. LONG: I am just wondering, Commissioner Moran, if perhaps Mr. Wasik could speak to when we

talk about the prolonged life of the asset, what that actually means for replacing that asset? And I think that's a consideration that, perhaps we are across people on the panel, that maybe you have something you would like to add for the panel to understand what that means.

T. WASIK: That's correct. So through a longer useful life of the asset what we do is we will maintain and keep it in operations and extract more value over the life of the asset itself, therefore reducing the need to fund its replacement and therefore providing benefit that way, as well. So there are secondary impacts in terms of valuing assets over a longer useful life and extracting value for the ratepayers from those assets, and we think that's appropriate.

PRESIDING COMMISSIONER MORAN: Fair enough, Mr. Wasik. Thank you for that. And presumably that would be the case regardless of what the depreciation schedule is for any asset, that's how you would normally be expected to manage your assets; right?

T. WASIK: In some regards when we think about setting standards and specifications on equipment and trying to extract a longer useful life of those assets, that's a consideration that we have up front as well. And so, for us it's sort of looking at ensuring that when we procure and construct and implement these long life assets we extract the

maximum value at the time, which I think is of greater value to our ratepayers.

PRESIDING COMMISSIONER MORAN: Right. And, as I indicated, that would be the case regardless of whether the asset in question, based on an asset life study, said it's 50 years and then a subsequent said, no, actually 60 years is a better life. You would still be doing that regardless; right?

T. WASIK: Well, my position on that is that the specific calculations, and the quality of materials, and the construction materiality and how you construct it do inform the useful life, and so it works the other way, is that we are informed by how we build it and how long we expect it to operate and our experience of paying, perhaps a premium for better materials because we are going to get longer life, is all part of that rationale of determining the useful life.

PRESIDING COMMISSIONER MORAN: Understood, understood. With respect to the opening rate base question then, I think you have indicated that, yes, the opening rate base would be higher than it otherwise would have been. But for the change in the depreciation schedule, can we just get back on track there.

M. VILLETT: Yes, that's correct. Because the useful lives have been extended -- in general have been extended.

PRESIDING COMMISSIONER MORAN: Okay. So I guess the question I have for you is, I get the accounting side of it. IFRS says you have got to start implementing whatever the result is from your study. How does that work in a PBR context where rates get set, you have an envelope for OM&A, you have got an envelope for capital and the rates are set on the basis of an existing depreciation schedule, asset life study and all of that? On what basis, ultimately, can PBR work effectively if, during the course of that PBR term, you can do a study on cost allocation and say I am reallocating my costs; it's kind of changing everything internally, so from an accounting point of view I am just going to change that, but wait a minute, I am still in a PBR term. Maybe I will get a deferral account to retroactively change my rates to reflect that, or I do another life of asset study and it changes again. How does that fit if it's going to be subject to change during the course of a PBR term? I am trying to understand how -- I mean, IFRS works on annual basis; PBR works on a five-year basis. How do you kind of make sure that you're not changing, in effect, having a retrospective impact on rates as a result of that?

M. VILLETT: I think we partially addressed some of this question in the response to 2-Staff-153, and there we referenced, again, the accounting procedures handbook and it states that the Board is mindful that

change in useful life depreciation methods could occur annually, regardless of whether the Board has approved such changes. However the board's position is to encourage, to the extent possible, symmetry between the regulatory reporting for capital assets in order to have more regulatory -- to have more readily available and verifiable information to assist in rate base through the financial statements.

And from an Alectra perspective, I think what we tried to do, there can be a -- I think there is a bit of a timing difference between the requirements under IFRS and the length of a custom application like this. So once we completed the depreciation study and the useful life study, those were completed in 2025, we were requiring IFRS to update our financial statements. We started those studies in 2024, they were completed in 2025, they were -- we then updated our financial plan, which was approved in May of 2025, we filed our application in October 2025, and we've -- since then we have been going through the regulatory process.

So I think, you know, we did our best to basically prepare these studies as late as possible in the process, but given the length of a custom application, it extends more than 12 months, there is going to be some types of disconnects. And I think the OEB, in the accounting procedures handbook, has recognized this in some of the quotes that I have

mentioned and they have encouraged the symmetry. But just with the length of the process, I think, you know, naturally there could be some differences.

PRESIDING COMMISSIONER MORAN: Okay. So I am almost done with this line of questioning. The -- in the context of setting just and reasonable rates, base rates are set with an assumed depreciation schedule, and during the IRM period, the ratepayers presumably have some expectation that that rate base is being depreciated at the rate at which those rates were set on. And so, if you change that in midstream, with the result that the opening rate base for the next term is higher than it would otherwise be, how do you justify that to the ratepayers to say, you know, yes, you were paying rates assuming that these assets would be depreciated at this level, but now we are going to depreciate them more slowly because we have discovered that these assets last longer? How do you justify to ratepayers that, you know, the outcome which is that instead of an opening rate base being, you know, showing the result of depreciation as originally provided for in the base, in the original base rates being higher than that? Isn't that sort of like the bank saying, oh, you want to amortize longer, but the principal is going to go up. That seems kind of a problem, isn't it? For the customer here, I mean, I get the idea that as much as possible symmetry between the two sets of books is an

objective, but leaving that aside, there is the more basic principle about, you know, ratepayers expecting to pay at a certain rate and now they are looking like their principal suddenly increased as a result of the study and they are going to pay much longer.

N. YEATES: So to address that, you know, for that reason, that is why our proposal is to refund customers these impacts in the deferral and variance accounts, right? For that exact reason, it is to our proposal in the application and as settled with the parties is to provide customers with a refund across all our rate zones for these impacts to the change in the financial useful lives of the assets.

PRESIDING COMMISSIONER MORAN: And that's going to be done through a rate rider?

N. YEATES: Correct.

PRESIDING COMMISSIONER MORAN: Right. So why wouldn't that rate rider just continue right through the whole term then, because that impact doesn't stop at rebasing. I mean, it continues through, right? You said you base up here; why wouldn't you continue that rate rider for the five years of the term as well, too, because that impact continues.

N. YEATES: Addressing the impact through the rate rider allows us to achieve two objectives: Ensuring that the customers are refunded the impact of the change in '25 and '26, but also ensuring that other important principle, which is that symmetry

between our financial and regulatory accounting, and ensuring that, you know, we don't create this permanent disconnect when filing annual RRR reporting, filing our fixed asset continuity schedules, because those differences will persist for 50, 60 years.

PRESIDING COMMISSIONER MORAN: So the rate rider we are talking about for the two years doesn't cause that disconnect, does it?

N. YEATES: No, it will not.

PRESIDING COMMISSIONER MORAN: So if you extended it for the five-year term, I mean, presumably it is not the same term, so there is no disconnect, right?

N. YEATES: But the rider calculates the impact to customers in 2025 and 2026, from that change.

PRESIDING COMMISSIONER MORAN: Right. So you have got the methodology that tells you what it was in '25 and '26, and you can continue that methodology for '27 through '31, right?

J. MYERS: Perhaps, Ms. Yeates, you can speak to the depreciation expense impact going forward.

M. VILLETT: Well, as a result of the new depreciation study that was filed in the application, the asset lives have in general been extended, so the annual depreciation impacts would be lower on a per year basis.

PRESIDING COMMISSIONER MORAN: And I assume that

would be the case when you compare 2025 to 2026; it will be a bit lower in '26 as well, based on your methodology?

M. VILLETT: All things being equal, the depreciation would be lower after we have implemented the study versus the rates that were previously -- the depreciation rates that were embedded in, prior to implementing the study.

PRESIDING COMMISSIONER MORAN: Okay. I think those are all my questions on this point. And I am just wondering if there is any input from any of the intervenors who want to add anything at this point? Don't feel like you have to.

M. RUBENSTEIN: No, but maybe it would be best to just take a quick break, if we can reconvene, just for a moment?

PRESIDING COMMISSIONER MORAN: Sure. It's 11:30. Why don't we adjourn for 15 minutes and leave it at that. Thanks.

--- Upon recessing at 11:29 a.m.

--- Upon resuming at 11:47 a.m.

PRESIDING COMMISSIONER MORAN: Thank you. Please be seated.

All right. Mr. Myers, do you have any questions you want to pose to your witnesses before we wrap up?

J. MYERS: No questions for me, but just two follow-ups from our panel. So I will turn it over to Ms. Yeates.

N. YEATES: Thank you. The first is to address Commissioner Sword's question regarding the Energy East consultation cost. So I do have an answer for you.

So in 2014, when the account was established, the Board advised various stakeholders that they would share the cost of these proceedings, similar to OEB assessment costs.

As a result, LDCs paid their proportional share of the incurred Energy East pipeline project consultation cost. So the deferral account that we have tracks the consultation costs allocated by the OEB to regulated distributors. So it's under $200,000, across the three of our five rate zones. And that's the genesis of the balances in that account. Thanks.

And on the second item, it is related to the useful life and DLC impacts. And the approach that we took when we calculated these balances, and the proposed refund through rate riders for customers is the same approach that was taken by LDCs on the transition to IFRS.

So at that time the board required distributors to track the impact of those changes, in most cases the change to the useful lives, in Account 1576. And part of that calculation includes a rate-of-return component that's applied to the balance to be refunded to customers.

So in our case -- and in that case, on the transition to IFRS, it happened during the IRM term for most utilities. And in our case, and in calculating the balance that we propose to refund to customers, we used the exact same approach as we did upon that transition to IFRS, and specifically the accounting approach for Account 1576.

PRESIDING COMMISSIONER MORAN: Thank you. Mr. Myers, any other matters that you want to raise?

J. MYERS: Nothing further. Thank you.

PRESIDING COMMISSIONER MORAN: Anything from anybody else? Okay. Hearing none.

So thank you very much for your presentation and your responses to our questions. It's been very helpful. We are getting our heads around the proposal, and as I am sure you can tell, we have a couple of questions in our heads around aspects of it, but we do appreciate the time and effort that everybody put in to producing the settlement proposal, along with assisting us here today. So thank you very much. And we are adjourned.

--- Whereupon the proceeding concluded at 11:50 a.m.