

September 18, 2026

VIA EMAIL

Arbitration Place

Email: production@arbitrationplace.com

Attention: Production Department

Dear Arbitration Place Production Department;

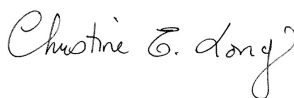
RE: OEB File No. EB-2025-0252, Alectra Utilities Corporation (“Alectra Utilities”) 2027-2031 Custom Rate Application for Electricity Distribution Rates and Charges (the “Application”) – Settlement Presentation Day Transcript Corrections

Alectra Utilities has reviewed the transcript from the Settlement Proposal Presentation on Tuesday, September 15, 2026 and requests that the transcript be corrected for the following errors. Please note that the page and line numbers mentioned are in reference to the top-right page numbers of the transcript, and not the PDF page numbers.

- **Throughout Transcript:** Panelist name “M. Villet” or “Mark Vetsis” or “Mr. Villet” and “Mark Villet” should read “M. Villett” or “Marc Villett” or “Mr. Villett” and “Marc Villett”
- **Page 13, line 4:** “Unreliability” should read “On reliability”
- **Page 50, line 17:** “rationcar” should read “rationale”

Should you have any questions, please do not hesitate to contact the undersigned.

Sincerely,



Digitally signed by Christine E.
Long
Date: 2026.09.18 15:36:03 -04'00'

Christine E. Long

Senior Vice-President Regulatory Affairs and Privacy Officer

Christine.Long@alecrautilities.com

cc: All parties

Natalie Yeates, Alectra Utilities

Charles Keizer, Daliana Coban, and Jonathan Myers, Torys LLP



ONTARIO ENERGY BOARD

FILE NO.	EB-2025-0252	Alectra Utilities Corporation
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DATE:	September 15, 2026
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BEFORE:	Patrick Moran	Presiding Commissioner
	David Sword	Commissioner
	Shadrzad Rahbar	Commissioner

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	Board Staff
ASTRIT SHYTI	
PAULINE SHEN	
PETAR PRAZIC	
ABDULLA HUSAIN	
DALIANA COBAN	Alectra Utilities Corporation
JONATHAN MYERS	
CHRISTINE LONG	
TOM WASIK	
NATALIE YEATES	
MARCK ~~VILLETT~~ <u>TSIS</u>	
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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1 Toronto, Ontario

2 --- Upon commencing on Tuesday, September 15,
3 2026, at 10:03 a.m.

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

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

17 **LAND ACKNOWLEDGMENT**

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

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

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

19 **APPEARANCES**

20 J. MYERS: Thank you and good morning. My name
 21 is Jonathan Myers. I am counsel to Alectra. With me
 22 here today is my co-counsel Daliana Coban. And from
 23 Alectra we have, to my right, is Christine Long,
 24 senior vice president of regulatory. Over on our
 25 panel today, on the left, we have Tom Wasik, senior
 26 vice president asset management. In the middle,
 27 Natalie Yeates, vice president regulatory, and Marc~~ck~~
 28 ~~Villette~~~~tsist~~, senior vice president finance. And

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

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

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

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

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

13 PRESIDING COMMISSIONER MORAN: Are there other
14 appearances?

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

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

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

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

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

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

1 in Ontario.

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

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

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

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

18 T. WASIK: Good morning. Tom Wasik.

19 N. YEATES: Natalie Yeates.

20 M. VILLETT: Marc* Villettt.

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

25 T. WASIK: I do.

26 N. YEATES: I do.

27 M. VILLETT: I do.

28 COMMISSIONER RAHBAR: Thank you. Second

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

3 T. WASIK: I do.

4 N. YEATES: I do.

5 M. VILLET^T: I do.

6 COMMISSIONER RAHBAR: Thank you. Appreciate
7 that.

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

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

13 **PRESENTATION BY N. YEATES:**

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

22 Alectra has been asked to present a summary of
23 the settlement proposal reached in EB-2025-0252, our
24 2027 to 2031 custom IR application. The settlement
25 proposal was originally filed on July 30th, an
26 updated version of the settlement proposal, and this
27 presentation was filed on September 11th. Before we
28 begin, we want to acknowledge the work of the

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

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

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

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

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

11 Next slide, please. Turning to the framework
12 itself, the parties have agreed to a custom incentive
13 rate framework built off a full cost of service
14 rebasing in 2027 followed by a formulaic approach for
15 2028 through 2031. In 2027, there is a complete
16 review of the service revenue requirement and other
17 revenue, which yields the base revenue requirement
18 used to set distribution rates. That is a
19 conventional rebasing year and it anchors everything
20 that follows. For 2028 to 2031, rates escalate by a
21 custom price cap index, which is inflation plus a
22 revenue growth factor. Inflation is the OEB's
23 annually published inflation factor for electricity
24 distributors, so it updates each year with the
25 Board's own published figure.

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

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

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

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

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

9 2027 begins with the 2026 OEB-approved rates in
10 each rate zone, plus the cost of service component,
11 plus one-fifth of the harmonization component. From
12 2028 onward, the prior year's rate is escalated by
13 the custom price cap index and then the next one-
14 fifth of the harmonization component is added, which
15 is also escalated by the index. By 2031, all five
16 rate zones arrive at the same harmonized end-state
17 rate. The reason for the five-year phase-in is
18 customer impact mitigation, and spreading it over
19 five equal tranches keeps the annual movement gradual
20 and predictable.

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

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

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

5 The system itself comprises 149 municipal
6 stations, over 128,000 distribution transformers,
7 roughly 23,700 kilometres of underground cable and
8 18,500 kilometres of overhead wire, more than 134,000
9 poles and over 6,600 primary switches.

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

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

28 On a capital expenditure, the settled five-year

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

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

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

28 How do we manage a reduction of this magnitude?

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

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

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

18 Next slide, please.

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

1 The scorecard commits Alectra to measurable
2 targets across five reporting categories:
3 Reliability, cost control, infrastructure renewal,
4 automation, and meeting capacity needs. On
5 ~~Un~~reliability, the settled SAIDI target by 2031 is
6 0.878 hours, excluding major event days and loss of
7 supply. I would note that the settled target equals
8 the OEB's own reliability performance improvement
9 target, so are being held to the Board standard. The
10 failed equipment customer hours interrupted target
11 settled at 434,239 hours.

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

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

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

23 On automation, the settled annual targets are
24 85, 55, 75, 90, and 90 devices across 2027 to 2031,
25 and on capacity, 625 MVA of added station capacity.

26 I will now pass on to Marc Villette.

27 M. VILLETT: Thank you. Next slide.

28 So overall, the settlement agreement reduces our

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

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

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

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

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

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

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

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

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

10 The Group 2 balances for the Enersource, Horizon
11 and Powerstream rate zones are disposed of over the
12 2027 to '31 period. For the Brampton rate zone over
13 the 2028 to '31 period, and for the Guelph rate zone
14 over the 2029 to '31 period, in order to mitigate the
15 2029 rate impact resulting from the expiry of the
16 Guelph rate zone specific price cap adjustment rate
17 riders.

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

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

26 Next slide, please.

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

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

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

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

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

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

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

28 Based on the settlement proposal, the five-year

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

11 Next slide please.

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

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

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

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

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

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

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

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

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

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

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

1 you.

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

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

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

24 That concludes our presentation.

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

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

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

8 Thank you.

9 PRESIDING COMMISSIONER MORAN: Thank you,
10 witnesses.

11 Commissioner Sword, you have some questions?

12 COMMISSIONER SWORD: Thank you.

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

15 H. LIM: I do.

16 COMMISSIONER SWORD: Would you mind turning to -
17 - it was part of the application, October 14th, 2025,
18 the original application. I have it as page 305 of
19 1738. And what you will see is a map of the service
20 area.

21 H. LIM: One moment.

22 COMMISSIONER SWORD: Sure.

23 H. LIM: Sorry, 1738?

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

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

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

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

6 COMMISSIONER SWORD: Sure. That's fine.

7 J. MYERS: So slide 5 from the presentation.

8 H. LIM: I will share the screen.

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

14 N. YEATES: That is correct.

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

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

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

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

10 N. YEATES: Correct.

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

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

28 COMMISSIONER SWORD: Okay. And were there any

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

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

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

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

22 COMMISSIONER SWORD: With shareholders
23 shouldering accountability for that cost?

24 N. YEATES: Correct.

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

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

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

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

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

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

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

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

28 COMMISSIONER SWORD: Okay. Brampton seemed to

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

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

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

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

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

26 N. YEATES: That is correct.

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

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

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

7 COMMISSIONER SWORD: Okay.

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

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

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

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

20 J. MYERS: Okay. Thank you.

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

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

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

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

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

28 COMMISSIONER SWORD: Sure, okay. I am aware

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

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

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

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

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

23 COMMISSIONER SWORD: Thank you. All right.

24 Commissioner Moran?

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

27 R. DHILLON: I will mark that as undertaking JP-
28 1.1.

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

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

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

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

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

17 COMMISSIONER SWORD: Yes, which gave rise to it.

18 J. MYERS: Okay.

19 COMMISSIONER SWORD: Thank you.

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

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

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

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

1 structures to serve?

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

16 COMMISSIONER RAHBAR: Thank you. That's
17 helpful.

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

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

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

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

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

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

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

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

21 COMMISSIONER RAHBAR: Thank you.

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

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

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

7 So did I understand your answer correctly?

8 N. YEATES: What we were able to do is when we
9 developed the 2027 distribution rates, it flowed from
10 our 2027 revenue requirement. And then what we were
11 able to do as an additional step is to compare the
12 2026 OEB-approved rates to the 2027 rate, and what
13 was important for us is to identify that increase, to
14 identify the drivers for that increase. And we knew
15 that there were two. One was the impact of
16 harmonization across the rate zone and then, two, the
17 impact of cost of service.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

23 N. YEATES: Correct.

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

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

6 N. YEATES: Yes.

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

10 N. YEATES: Correct.

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

16 N. YEATES: That's correct.

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

19 All right.

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

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

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

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

28 And so, the OEB has prescribed a BCA framework

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

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

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

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

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

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

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

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

17 PRESIDING COMMISSIONER MORAN: Okay, thank you.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

20 M. VILLET: All right. I understand the
21 principle of what you're saying, but you're also --
22 yeah, I understand the principle, what you're getting
23 at.

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

1 N. YEATES: I just wanted to add, one of the
2 reasons why we are proposing to refund customers
3 these impacts through the rate riders is because in
4 2025 and 2026, those two years in which we
5 implemented the change in our fixed asset subledger,
6 the underlying rates -- the rates that customers are
7 paying in those two years are essentially higher than
8 what they otherwise would be. So therefore, in those
9 -- what we are doing here is trying to ensure that
10 customers remain whole and are refunded in 2027 the
11 impact of those changes in 2025 and 2026.

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

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

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

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

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

12 M. VILLET: Yes, that's correct.

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

21 M. VILLET: Yes.

22 PRESIDING COMMISSIONER MORAN: Okay. That
23 amount that's going to be rebated, are you proposing
24 --

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9 And from an Alectra perspective, I think what we
10 tried to do, there can be a -- I think there is a bit
11 of a timing difference between the requirements under
12 IFRS and the length of a custom application like
13 this. So once we completed the depreciation study
14 and the useful life study, those were completed in
15 2025, we were requiring IFRS to update our financial
16 statements. We started those studies in 2024, they
17 were completed in 2025, they were -- we then updated
18 our financial plan, which was approved in May of
19 2025, we filed our application in October 2025, and
20 we've -- since then we have been going through the
21 regulatory process.

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

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

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

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

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

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

16 N. YEATES: Correct.

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

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

1 between our financial and regulatory accounting, and
2 ensuring that, you know, we don't create this
3 permanent disconnect when filing annual RRR
4 reporting, filing our fixed asset continuity
5 schedules, because those differences will persist for
6 50, 60 years.

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

10 N. YEATES: No, it will not.

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

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

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

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

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

28 PRESIDING COMMISSIONER MORAN: And I assume that

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

4 M. VILLET^T: All things being equal, the
5 depreciation would be lower after we have implemented
6 the study versus the rates that were previously --
7 the depreciation rates that were embedded in, prior
8 to implementing the study.

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

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

17 PRESIDING COMMISSIONER MORAN: Sure. It's
18 11:30. Why don't we adjourn for 15 minutes and leave
19 it at that. Thanks.

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

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

22 PRESIDING COMMISSIONER MORAN: Thank you.
23 Please be seated.

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

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

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

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

9 As a result, LDCs paid their proportional share
10 of the incurred Energy East pipeline project
11 consultation cost. So the deferral account that we
12 have tracks the consultation costs allocated by the
13 OEB to regulated distributors. So it's under
14 \$200,000, across the three of our five rate zones.
15 And that's the genesis of the balances in that
16 account. Thanks.

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

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

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

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

10 J. MYERS: Nothing further. Thank you.

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

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

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