ERTH

Defining Influence

BY E-MAIL

July 29, 2026

Ritchie Murray
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ritchie Murray:

Re: Response to Interrogatories

Application by ERTH (Westario) Acquisition Inc. under section 86(2)(a) and 86(1)(c) of the *Ontario Energy Board Act, 1998* to acquire 100% of the shares of Westario Power Inc. and to subsequently amalgamate Westario Power Inc. and ERTH (Westario) Acquisition Inc. to create a new company operating under the name Westario Power Inc.

-and-

Application by ERTH Corporation under section 86(2)(a) of the *Ontario Energy Board Act, 1998* to acquire 100% of the shares of Tillsonburg Hydro Inc.

Ontario Energy Board File Numbers: EB-2026-0137 and EB-2026-0145

In accordance with Procedural Order No. 1, please find attached the Applicants' Responses to Interrogatories in the above noted proceedings. The Applicants and all intervenors have been copied on this filing.

Any questions relating to this letter should be directed to Tyler Moore at tyler.moore@erthcorp.com or at 226-926-8654.

Yours truly,

Tyler Moore

cc: Chris White, ERTH Corporation
Kyle Pratt, Tillsonburg Hydro Inc.
Wally Malcolm, Westario Power Inc.
Lizzie Zhang, OEB
Tom Ladanyi, Energy Probe
Michael Brophy, Pollution Probe
John Vellone/Scott Pollack, BLG LLP

Responses to Interrogatories

ERTH (Westario) Acquisition Inc. / Westario Power Inc. [EB-2026-0137]

and

ERTH Corporation / Tillsonburg Hydro Inc. [EB-2026-0145]

This Responses to Interrogatories document is divided into the following three sections:

1) Section 1: Responses solely to interrogatories in the EWAI/Westario (EB-2026-0137) including:
    a) Pollution Probe
    b) OEB Staff

2) Section 2: Responses solely to interrogatories in the ERTH/Tillsonburg proceeding (EB-2026-0145) including:
    a) Energy Probe
    b) Pollution Probe
    c) OEB Staff

3) Section 3: Reponses to combined interrogatories applicable to both proceedings including:
    a) Pollution Probe
    b) OEB Staff

To promote clarity and efficiency, the Applicants will use the following terms in this Responses to Interrogatories document:

Glossary of Key Items for Response to Interrogatories	
Definition	**Acronym / Label Used**
EB-2026-0137 Application by ERTH (Westario) Acquisition Inc. to acquire all shares of and subsequently amalgamate with Westario Power Inc.	WPI Application
EB-2026-0145 Application by ERTH Corporation to acquire all shares of Tillsonburg Hydro Inc.	THI Application
ERTH (Westario) Acquisition Inc.	The Applicant
OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* (July 11, 2024)	MAADs Handbook
Tillsonburg Hydro Inc.	THI
Westario Power Inc.	WPI
ERTH Corporation	The Applicant or ERTH Corporation or ERTH
ERTH Power Corporation	ERTH Power Corporation, ERTH Power, or EPC

SECTION 1: EWAI/Westario Interrogatories

Section 1(a) – Pollution Probe

WPI-PP-16

Reference

None.

Question

(a) Please explain why Westario Power Inc. is being acquired via ERTH (Westario) Acquisition Inc., when THI is being acquired directly by ERTH Corporation. What is the purpose of the additional corporate structure and does this get removed following Phase 2?

Response

(a) The Applicant respectfully submits that this is not relevant to the WPI proceeding. As set out in the Decision and Order in EB-2005-0234/0254/0257[1] and reiterated in the MAADs Handbook[2], the Board's role in this proceeding is not to determine whether another transaction, whether real or potential, can have a more positive effect than the one that has been negotiated to completion by the parties.

WPI-PP-17

Reference

None.

Question

(a) Was there any public consultation conducted to engage the community and ratepayers during this process? If not, why not. If yes, please provide copies of the materials used and copies of the feedback collected.

Response

(a) The Applicant respectfully submits that this is not relevant to the WPI proceeding. Pursuant to the MAADs Handbook[3], the OEB will not consider issues relating to the

[1] EB-2005-0234/0254/0257, Decision and Order, page 6.
[2] MAADs Handbook, Section 4.3, page 14-15.
[3] MAADs Handbook, Section 4.3, page 14-15.

extent of the due diligence or public consultation and applicants are directed not file details of public consultation prior to the filing of the application.

WPI-PP-18

Reference

None.

Question

(a) Please provide responses (if any) to community and ratepayer input/comments, including (but not limited to) those filed with the OEB.

Response

(a) The Applicant respectfully submits that this is not relevant to the WPI proceeding on the grounds described in response to WPI-PP-17 above.

WPI-PP-19

Reference

None.

Question

(a) Please provide a copy of any business case, presentations or similar documents provided to the WPI and/or EPC Board of Directors and/or their direct or indirect shareholders with respect to the approval transaction (either preliminary or final approval).

Response

(a) The documents described in WPI-PP-19 contain details regarding (i) negotiations leading to the proposed WPI transaction, (ii) alternative transactions that may have been considered, (iii) the due diligence process, (iv) the results of public consultations conducted before filing the Application, (v) the contents of draft purchase agreements and confidential negotiating documents, and (vi) discussions regarding negotiating strategies. Accordingly, pursuant to the MAADs Handbook[4], the Applicant respectfully submits that this is not relevant to the WPI proceeding.

[4] MAADs Handbook, Section 4.3, pages 14-15.

WPI-PP-20

Reference

None.

Questions

(a) Please describe how local planning and delivery (including municipal energy and emissions planning and support aligned with the Distribution System Plan) will be impacted if the acquisition is approved. If incremental benefits will result to enhance energy and emissions planning, alignment and activities in the municipality, please provide details.
(b) Please describe what utility activities (including eDSM promotion and delivery) the acquisition will maintain or enhance to support ratepayer programs and regulated energy and emissions reporting and reductions requirements under Ontario requirements for municipalities and all broader public sector buildings served.

Responses

(a) The Applicant respectfully submits that that the degree to which the proposed transaction impacts local planning and delivery of municipal energy and emissions planning and support is not relevant to the WPI proceeding as the requested information is not relevant to the OEB's statutory objectives as set out in section 1 of the *Ontario Energy Board Act, 1998,* as assessed pursuant to the MAADs Handbook.[5]

(b) The Applicant respectfully submits that this is not relevant to the WPI proceeding. Pursuant to the MAADs Handbook[6], the OEB has identified that evidence relating to conservation is not relevant to the MAADs approval proceeding

WPI-PP-21

Reference

The Applicant intends to maintain a local physical presence no different than what Westario's customers experience today. WPI's existing service center will continue to operate in Walkerton and front-line operations staff that currently respond to outages and power quality issues are expected to continue to serve the same communities. [Page 26]

Questions

[5] MAADs Handbook, Sections 3 and 4, pages 6-15.
[6] MAADs Handbook, Sections .4.2 and 4. 3, pages 9 and 15.

(a) Please explain any expected decrease in functions at the WPI office in Walkerton following Phase 1 and/or Phase 2 transactions. Please explain where those functions will move to and the expected decrease in WPI office space. If annual savings estimates are available, please also provide them.
(b) Please provide the most recent three years of (OM&A and Capital) costs related to the WPI office in Walkerton.
(c) Does WPI or ERTH have an estimate of costs and/or benefits (OM&A and Capital) if the WPI office is downsized or closed. If yes, please provide them.

Responses

(a) There will be no expected decrease in functions at the WPI office in Walkerton following the Phase 1 transaction, which is the subject of this Application. Any changes to the functions at the WPI office in Walkerton following the merger of WPI, EPC, and THI will be dealt with in the Phase 2 application.

(b) The most recent three years of (OM&A and Capital) costs related to the WPI office in Walkerton are set out below:

Administration Building Costs

		2023 YTD	2024 YTD	2025 YTD	upto Jun 2026 YTD	2026 Budget
567500	Maintenance of General Plant	50,987.3	46,744.9	36,840.6	27,819.6	41,710.0
567510	Office Cleaning and Cleaning Supplies	35,797.1	35,066.4	41,414.9	20,142.5	51,162.0
567520	Snow Removal & Lawn Care	26,869.6	37,712.8	75,428.4	55,721.8	28,392.0
567530	Office Utilities	28,427.2	29,877.9	31,116.3	16,794.5	33,070.0
	Total Maintenance & Expenses	142,081.2	149,402.0	184,800.2	120,478.4	154,334.0

Capital Expenditures		2023 YTD	2024 YTD	2025 YTD	2026 YTD	2026 Budget
	Roof	155,980				
	Lighting	10,411				
	Heat Pump	6,044				
	Other	0	0	0	5,627	20,000
180800	Buildings and Fixtures	172,435	0	0	5,627	20,000
191000	Leasehold Improvements	0	0	0	0	0
	Total Capital Expenditures	172,435	0	0	5,627	20,000

(c) Please see the response to THI-PP-21(b) above

WPI-PP-22

Reference

For purposes of this Application, it is critical to note that Westario's existing cost structures have recently been approved by the OEB as necessary to maintain ongoing financial and operational viability. It can reasonably be assumed that maintaining Westario's existing expenditure levels is sustainable from an operational and financial perspective over the rebasing period proposed in this Application. [Page 26]

Questions

(a) Please provide a table of the OEB approved budgets by major category for the current approved rate term and add columns to extrapolate those out to the end of the 9 year rates deferral term requested.
(b) Please provide a copy of the table requested in part a, removing the proposed synergies, by year.
(c) Please provide the total OM&A and Capital funding difference between the responses for part a and b, above.

Responses

(a) A table of the OEB approved rate term budgets by major category (2024-2028) is set out below:

CATEGORY	Forecast Period (planned)				
	2024	2025	2026	2027	2028
	$ '000				
System Access	1,794	1,862	1,891	1,947	2,003
System Renewal	4,535	5,193	5,269	5,411	5,433
System Service	353	373	377	391	406
General Plant	490	582	745	709	608
TOTAL EXPENDITURE	7,172	8,010	8,282	8,458	8,450
Capital Contributions	- 881	- 908	- 925	- 944	- 963
NET CAPITAL EXPENDITURES	6,291	7,102	7,357	7,514	7,487
System O&M	$ 2,585	$ 2,650	$ 2,716	$ 2,784	$ 2,853

Please note that the table above only includes capital expenses as WPI does not provide OM&A expenses by year beyond the 2024 test year.

Table of the OEB approved rate term budgets by major category post 2028 will be included in the Phase 2 application.

(b) The table set out in response to WPI-PP-22(a) does not include synergies.

(c) Not applicable, as described above.

WPI-PP-23

Reference

The transition begins with the Phase 1 Transaction, which is the subject matter of this Application. Phase 1 is expected to produce moderate synergies. These modest cost savings are possible

related to the elimination of costs related to the WPI President & CEO role discussed below and a reduction in various redundant expenses (e.g. board remuneration, industry associations, etc.), which will be largely offset by cost of the shared corporate services provided by ERTH. ERTH intends to expand its corporate resources and reallocate corporate resources from its competitive businesses to provide oversight and management of WPI. [Page 22] and Table 5: Forecasted Revenue Requirements – Status Quo vs. Post Transaction

Questions

(a) Please provide the costs related to the individual management role and the various redundant expenses expected to be reduced.
(b) Please provide the details of the annual synergies in Table 5 - Forecasted Revenue Requirements – Status Quo vs. Post Transaction. If an excel sheet is available for the synergy details, please provide a copy.
(c) Please explain the impact of the OEB approving Phase 1, but rejecting Phase 2. If there is an impact to proposed synergies, please provide an update to Table 5 based on only approval of Phase 1.
(d) Please reconcile and explain the differences in WPI Synergies in Table 5 with the WPI Synergies by year identified in Table 5 of the ERTH-Tillsonburg Application (EB-2026-0145), which also includes WPI synergies.

Responses

(a) Please see response to WPI-PP-23(b) below.

(b) The details of the annual synergies in Table 5 - Forecasted Revenue Requirements – Status Quo vs. Post Transaction are set out below:

WDI Operating Synergies	2026 1/2 yr	2027	2028	2029	2030	2031	2032	2033	2034	2035
CEO	172,500	355,350	366,011	376,991	388,301	399,950	411,948	424,306	437,036	450,147
Board Expenses		80,000	82,400	123,600	127,308	131,127	135,061	139,113	143,286	147,585
Board D&O insurance	-			9,000	9,270	9,548	9,835	10,130	10,433	10,746
Membership Fees				72,000	74,160	76,385	78,676	81,037	83,468	85,972
COS Regulatory Costs				75,000	75,000	75,000	75,000	75,000	75,000	75,000
ERTH Corp Allocations	(152,864)	(314,899)	(324,346)	(334,076)	(344,099)	(354,422)	(365,054)	(376,006)	(387,286)	(398,905)
Vehicle branding & Lic	-	(40,000)	(40,000)							
New ERP - RFP costs	-	(30,000)	(30,000)							
IT Contingency (SCADA, SAP)				(275,000)	(275,000)					
Total	**19,636**	**50,451**	**54,065**	**47,514**	**54,940**	**337,588**	**345,466**	**353,580**	**361,937**	**370,545**

(c) The additional synergies identified anticipated to commence in 2029 (as noted in the table included in response to WPI-PP-23(b) above) will be eliminated if Phase 2 is not approved. Otherwise, there will be no impact on the Phase 1 (2026-2028) synergies in the above table if Phase 2 is not approved.

(d) The only differences between the WPI synergies presented in Table 5 of the WPI MAAD Application and the WPI synergies presented in Table 5 of the THI MAAD

Application are: (i) a minor rounding difference in 2032; and (ii) the omission of WPI synergies for the 2026 to 2028 period in the THI MAAD Application. The THI MAAD Application intentionally presents WPI synergies only from Phase 2 onward, as the Phase 1 transaction involving WPI was addressed in a separate application.

WPI-PP-24

Reference

Accordingly, the proposed transaction is forecasted to positively impact the customers of WPI with respect to adequacy, reliability, and quality of electricity service due to the efficiencies expected to be generated from the transaction. [Page 27]

Questions

(a) Please provide the estimated improvements expected with respect to WPI adequacy, reliability, and quality of electricity service due to the efficiencies expected to be generated from the transaction. Please also explain how these will be tracked and reported to the OEB in comparison to historical results in Table 8.
(b) Would a single set of results for the merged utility be reported following Phase 2? If yes, please explain how that will enable comparison to the historical WPI results.

Responses

(a) The Applicant respectfully submits that it is premature to do a quantitative analysis of the estimated improvements expected with respect to WPI adequacy, reliability, and quality of electricity service but a general description of the improvements we expect to see are set out in Section 4.1 of the WPI Application. Any estimated improvements with respect to WPI adequacy, reliability, and quality of electricity service due to the efficiencies expected to be generated from the proposed transaction will be evidenced by comparisons to WPI's adequacy, reliability, and quality of electricity service pre-transaction.

(b) The Applicant respectfully submits that this is not relevant to the current WPI proceeding requesting approval of Phase 1. The way the merged utility reports its results will be addressed in the Phase 2 application.

WPI-PP-25

Reference

There will be a large benefit to Westario customers through all future phases of the transaction in

the form of technology enhancements in the Westario service territory that would otherwise not be economical or practical to implement. The proposed transaction incorporates the benefits to be realized through voluntary consolidation; it will deliver cost synergies and economy of scale benefits and will promote the Board's objectives. [Page 27-28, including list of examples]

Questions

(a) Please provide annual OM&A and Capital savings expected from the cost synergies and economy of scale benefits noted.
(b) Please indicate how these cost synergies and economy of scale benefits will be tracked for WPI over the deferred rates period and reported to the OEB at the time of rebasing.
(c) Please explain any incremental distribution energy resource or non-wire solutions opportunities that the enhanced technology and capacity would enable.
(d) What specific incremental results and benefits are expected for WPI as a result of access to ERTH's enhanced environmental, social and governance (ESG) functions.

Responses

(a) The minimal annual OM&A and Capital savings expected from the cost synergies and economy of scale benefits associated with Phase 1 are set out in Table 5 included with the WPI Application. A detailed description of the annual OM&A and Capital savings expected from the cost synergies and economy of scale benefits associated with Phase 2 will be set out in in the Phase 2 Application

(b) Please see response to Staff-25.

(c) The enhanced technology and capacity described in the WPI Application are expected to provide a number of incremental distribution energy resource ("DER") or non-wire solutions opportunities including, for example, optimizing WPI's localized DER dispatch and improving real-time grid visibility for non-wires alternatives (NWAs).

(d) Access to ERTH's enhanced ESG function is predicted to enable WPI to improve organizational performance by embedding sustainability, stakeholder considerations, and strong governance into strategic planning, operations, and decision-making. The resulting benefits may include reduced operating costs and environmental impacts through improved energy efficiency, emissions reduction, and climate resilience; enhanced employee engagement, safety, diversity, and retention; increased customer satisfaction and participation in energy efficiency and electrification programs; stronger community and municipal relationships; improved regulatory compliance and enterprise risk management; more transparent and accountable governance; and better access to financing and strategic partnerships. Ultimately, a mature ESG

function is intended to strengthen WPI's long-term resilience, supports the energy transition, enhances public trust, and creates measurable value for customers, municipal shareholders, employees, regulators, and the communities it serves.

WPI-PP-26

Reference

WPI will have access to ERTH's customer service practices which recently resulted in an increase in its OEB regulated Customer Satisfaction Survey results from 76% in 2023 to 94% in 2025. [Page 28]

Questions

(a) Please update Table 9 including 2025 results for all WPI and EPC Customer Focus Statistics.
(b) WPI Customer Satisfaction Survey results appear to be consistently higher than ERTH's. Please explain how leveraging ERTH's customer service practices will improve WPI customer results.

Responses

(a) Please see an update to Table 9 below setting out the 2025 results for all WPI and EPC Customer Focus Statistics:

Year	Commercial Services connected On-Time (Target:90%)		Scheduled Appointments met On-Time (Target: 90%)		Telephone Calls Answered On-Time (Target :65%)		First Contact Resolution		Billing Accuracy (Target:98%)		Customer Satisfaction Survey	
	EPC	WPI	EPC	WPI	EPC	WPI	EPC	WPI	EPC	WPI	EPC	WPI
2025	95.37%	100.00%	99.55%	99.73%	88.03%	86.84%	100.00%	99.07%	98.30%	99.72%	94.00%	93.00%

(b) The Applicant's goal is to ensure that any customer services best practices employed by EPC will ultimately be deployed at WPI, and vice-versa, following the closing of the proposed WPI transaction. For example, EPC may recommend or share improved customer service practices and technologies that will improve WPI's Telephone Calls Answered On-Time and First Contact Resolution results, which were lower than EPC's results in these areas in 2025.

WPI-PP-27

Reference

None.

Question

(a) Please explain if there are any issues should the OEB approve a WPI deferred rates period of up to 9 years approved on an interim basis and subject to the Phase 2 application review within 5 years. If the Phase 2 application is not filed within 5 years, then deferred rates period becomes 5 years for WPI. If this impacts the business case or benefits flowing to ratepayers, please identify what would specifically change.

Response

(a) Please see responses to Staff-5 and Staff-49.

WPI-PP-28

Reference

The integration costs will be financed through the anticipated productivity savings expected from the transaction during the period after the Phase 2 transaction. As always, there will be timing differences between expense outlays and their recovery. [Page 31]

Questions

(a) Please identify the integration costs from Phase 1, but before Phase 2.
(b) How will Phase 1 productivity costs be funded?
(c) Please explain how the relevance of Phase 2 anticipated productivity savings for OEB consideration in this Phase 1 application?
(d) How would this be treated if Phase 2 is not approved.

Responses

(a) Please see responses to Staff-16.

(b) Please see responses to Staff-16.

(c) The anticipated Phase 2 productivity savings are relevant in so far as without approval of the Phase 1 transaction, none of the Phase 1 or Phase 2 synergies will be possible.

(d) If Phase 2 is not approved, the Phase 1 transaction and integration costs will continue to be funded in accordance with response to Staff-16.

WPI-PP-29

Reference

Accordingly, the Applicants propose the WPI ESM to be effective years six to nine of the rebasing

deferral period proposed in this Application with the following structure: [Page 34]

- *The ESM will apply to actual achieved return on equity (ROE) of WPI relative to the OEB-approved ROE for WPI for the applicable rate year.*
- *The ESM will be triggered when WPI's achieved ROE exceeds the OEB-approved ROE by more than 300 basis points.*
- *For earnings in excess of this threshold, the Applicants propose a 50/50 sharing between customers and shareholders of WPI, consistent with the OEB's standard ESM design for consolidated utilities.*
- *The ESM will apply annually and will be calculated and reported as part of WPI's annual RRR filings and any subsequent OEB review processes.*

Questions

(a) Please explain how the WPI actual results can be used for ESM in years six through nine, if WPI no longer exists as a separate regulated utility following Phase 2 (e.g. prior to year six).
(b) Please explain how ESM would be calculated for the merged utility.

Responses

(a) Please see the response to Staff-25.

(b) The Applicant will submit an ESM proposal as part of its Phase 2 application.

WPI-PP-30

Reference

Rate harmonization may be addressed as part of the Phase 2 Transaction. [Page 34]

Questions

(a) Please explain what factors would lead to rate harmonization not being included as part of the Phase 2 application.
(b) Could the Phase 2 rate deferral period be a term different than the residual of the 9 year rate deferral period from the WPI Phase 1 proceeding? If yes, please explain how this would align with the Phase 1 decision requested.

Responses

(a) The Applicant respectfully submits that this question is too speculative to answer. The Phase 2 application has not yet been filed, and the circumstances that may exist at the time of that application cannot be determined with certainty at this time. The decision

regarding whether rate harmonization will form part of the Phase 2 application will be based on a number of factors that will be assessed closer to the time of filing, including the regulatory environment, operational considerations, customer impacts, integration progress, and any applicable OEB guidance or requirements in effect at that time.

The Applicant reiterates, however, that any subsequent deferred rebasing period will be less than 10 years after the OEB approval of this Application.

(b) Please see response to Staff-5 and Staff-49.

Section 1(b) – OEB Staff

Staff-1

Reference

Share Purchase Agreement
Ref: WPI MAADs Application, Appendix C - Share Purchase Agreement

Preamble:
There are various references throughout the Share Purchase Agreement to a "Disclosure Schedule". For example, page 16 of the Share Purchase Agreement notes that "[t]he Disclosure Schedule contains a complete and accurate list of the Owned Lands, including complete legal descriptions, and the particulars of the Leased Premises and Real Property Leases."
OEB staff has been unable to locate the "Disclosure Schedule".

Questions

(a) Please confirm where the "Disclosure Schedule" can be found in the WPI MAADs Application.
    i. If it is not in the current WPI MAADs Application, please provide it.
(b) Please confirm all other applicable appendices, schedules, etc., that make up the Share Purchase Agreement are included in the application.

Responses

(a) The purpose of the Disclosure Schedule referenced in the WPI Share Purchase Agreement ("SPA") is to qualify the standard representations and warranties made regarding WPI as a stand-alone utility as of the date that the SPA was executed. The contents of the Disclosure Schedule will be updated on the closing of the WPI transaction, if approved, via a bring-down certificate in which the representations and warranties made regarding WPI as a stand-alone utility will be updated. Given that the contents of the Disclosure Schedule exist for WPI whether the proposed WPI transaction proceeds or not, the Applicant concluded and respectfully submits that the contents of the Disclosure Schedule are not relevant to the WPI proceeding.

Notwithstanding the above, the Applicant submits that there are no items identified in the Disclosure Schedule that will affect the WPI's ability to provide safe, reliable service or materially alter the economics underlying the Application, including any concerns regarding WPI's financial viability. In the event there were any items in the Disclosure Schedule that identify a material matter that could affect the "no harm" analysis, the Applicant respectfully submits that these items would be

described directly in the Application.

(b) Confirmed.

Staff-2

Reference

Municipal Resolutions
Ref: WPI MAADs Application, Appendix C - Share Purchase Agreement, Resolutions, PDF p. 238-239

Question

(a) Please confirm that the municipal resolution noted in the reference is for the Township of North Huron.

Response

(a) Confirmed.

Staff-3

Reference

Regulatory Approval
Ref: WPI MAADs Application, Appendix C – Share Purchase Agreement, Section 12(a)(ii), p. 44 [PDF page 94 of 353]

Preamble:
A portion of reference 1 states the following: "Each of Buyer and Sellers will use its best efforts (which shall not be less than commercially reasonable efforts) to co-operate and assist the other, so that the OEB Approval can be obtained on or prior to May 30, 2026."

Questions

(a) Please describe any impacts due to the difference in the date of OEB approval per the Share Purchase Agreement to the proposed WPI transaction.
(b) With respect to the WPI MAADs Application, if approved by the OEB, please advise on the expected transaction closing date.

Responses

(a) The date set out in Section 12(a)(ii) of the Share Purchase Agreement (May 30, 2026)

was included simply as a target date to ensure the parties used the appropriate efforts to obtain OEB approval of the proposed WPI transaction. Accordingly, there are no impacts on the proposed WPI transaction due to a change in the actual OEB approval date.

(b) Pursuant to the definition of "Closing Date" in Appendix 1 of the Share Purchase Agreement, if approved by the OEB, the expected transaction closing date will be within thirty (30) days after the date on which the OEB issues the OEB Approval.

Staff-4

Reference

WPI Prior Commitments / Directives
Ref 1: WPI MAADs Application, p. 7
Ref 2: EB-2023-0058, Decision and Rate Order, April 30, 2024
Ref 3: EB-2024-0060 WPI 2025 IRM Application
Ref 4: EB-2025-0002 WPI 2026 IRM Application

Preamble:
The Application states that WPI last rebased for rates effective January 1, 2024 (EB- 2023-0058). Further, as part of Phase 1 of the transaction, WPI will remain a distinct legal entity operating under a separate licence with common corporate and financial oversight from ERTH Corporation.
OEB staff notes that in EB-2023-0058, the parties to that proceeding reached a complete settlement on all issues on the approved issues list. The OEB approved the settlement agreement.

Questions

(a) Please outline any commitments between parties resulting from the 2024 cost of service settlement agreement in EB-2023-0058 and/or any directives from the OEB in its decision.
(b) Please confirm that WPI, owned by ERTH Corporation, will implement and/or address the matters outlined pursuant to the 2024 cost of service settlement agreement and/or OEB decision in EB-2023-0058.
    i. For each commitment or directive, please specifically indicate in which future application they will be addressed.
(c) Please confirm if there are any OEB directives stemming from the decisions in references 3 and/or 4. If yes, please describe and identify if they have been or when they will be addressed.

Responses

(a) There are no commitments between parties resulting from the 2024 cost of service settlement agreement in EB-2023-0058 and/or any directives from the OEB in its

decision.

(b) Not applicable.

i. Not applicable.

(c) There was one Directive from WPI's 2024 Cost of Service Settlement Agreement in EB-2023-0058, as detailed below from the OEB in its decision.

> The OEB notes that the corrected balances proposed for disposition no longer reconcile with the 2023 amounts reported by Westario Power in April 2024 pursuant to the OEB's *Electricity Reporting and Record-Keeping Requirements* (RRR)[19]. The OEB expects that Westario Power will take the necessary steps to correct its RRR filing. The discrepancies are summarized in Table 7.2.

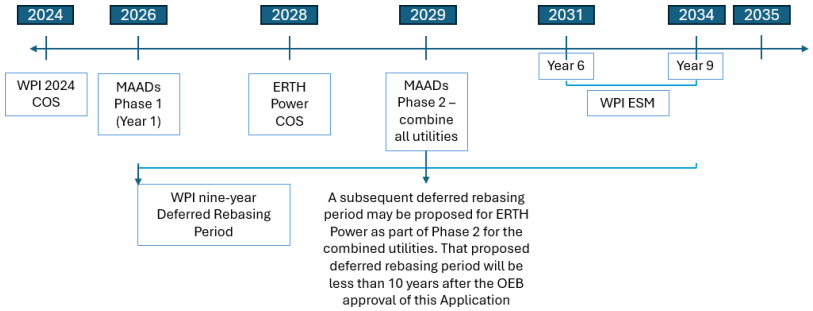
This Directive has already been fulfilled as part of WPI's recent IRM case.

Staff-5

Reference

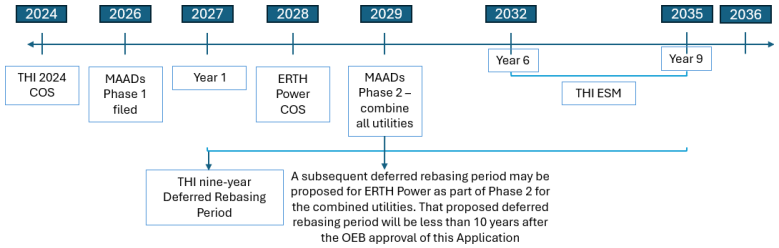
Timelines
Ref 1: WPI MAADs Application, pp. 7-8, 20-21, 24, 33
Ref 2: THI MAADs Application, pp. 7-8, 19-20, 23, 31

Preamble:
Based on the information provided in the WPI MAADs Application, OEB staff has developed the timeline below.



Based on the information provided in the THI MAADs Application, OEB staff has developed the timeline below.

OEB staff also note that:



- *Page 21 of reference 1 states, "It is the Applicant's intent at this point that a Phase 2 MAADs application would be filed in 2029". Page 19 of reference 2 states that the intent is that a Phase 2 MAADs application would be filed in 2029, while page 20 states the Phase 2 application will be submitted to the OEB in 2028.*

Questions

(a) Please confirm or correct OEB staff's assessment above based on the information provided in the respective applications.

(b) Please explain why the WPI MAADs Application portrays 2026 as Year 1, with consideration given to the filing date of the application, the OEB's performance standards for processing MAADs applications, and the potential time required for the transaction to close. OEB staff note that the THI MAADs Application portrays 2027 as Year 1.

i. Please provide a timeline or table clarifying the specific years for the following:
   - WPI Year 1
   - WPI Year 1 to Year 9 of the deferred rebasing period
   - The year that the Phase 2 application is expected to be submitted to the OEB.

Responses

(a) Confirmed.

(b) The WPI Application should have portrayed 2026 as Year 0 and 2027 as Year 1, as reflected in the THI application. When the WPI Application was being prepared it was anticipated that the filing would be submitted sooner than what was achieved. The timeline provided in the THI application is the appropriate timeline.

i. Please see the response to Board Staff-11 with respect to revenue requirement which details
   - 2026 – WPI Year 0
   - 2027 to 2035 – WPI Year 1 to Year 9 of the deferred rebasing period
   - 2029 – The year that the Phase 2 application is expected to be submitted to the OEB.

Staff-6

Reference

ERTH Power Corporation Rebasing
Ref: WPI MAADs Application, p. 7

Preamble:
Following the completion of Phase 1 transaction, ERTH Power Corporation will file its cost of service application for rates effective May 1, 2028.

Questions

(a) Please confirm that ERTH Power Corporation is to file its cost of service for May 1, 2028 rates by August 2027.
(b) Please provide thoughts of whether and how the rebasing application for ERTH Power Corporation following Phase 1 will account for the savings anticipated as part of Phase 2.

Responses

(a) Confirmed.

(b) The rebasing application for EPC following Phase 1 will not account for any savings anticipated as part of Phase 2. EPC is required to rebase in 2028 as per its previous acquisition of West Coast Huron Energy Inc. (EB-2018-0082). ERTH proposed a two-phase approach to facilitate this requirement and maintain the appropriate deferral period between Phase 1 and a rate harmonizing application.

Staff-7

Reference

WPI Employees
Ref 1: MAADs Application, Appendix C – Share Purchase Agreement, Section 8(e)(ii)
Ref 2: WPI MAADs Application, p. 21

Preamble:
A portion of reference 1 states that "Buyer shall retain all Employees employed with the Corporation immediately prior to the Closing Date and shall ensure that each such Employee shall remain employed on substantially the same terms and conditions and at the same location for a minimum duration of three (3) years following the Closing Date."
The Application seeks a nine-year deferred rebasing period for WPI. It is the Applicant's intent at this point that a Phase 2 application would be filed in 2029, following the conclusion of ERTH Power Corporation's cost of service application.

Questions

(a) Is it correct to infer from the above that following the Phase 1 transaction, all employees of WPI will, at a minimum, continue employment at WPI "on substantially the same terms and conditions and at the same location" until the Phase 2 application is filed?
(b) Will the Phase 2 application outline the plans for employees of the amalgamating LDCs?
(c) Please further explain the extent to which the Applicant foresees the Phase 1 transaction will impact the roles and functions of the existing WPI and ERTH Power Corporation staff, and in particular, all of the positions directly responsible for the maintenance of service quality and reliability of the distribution system.

Responses

(a) Yes (excluding the WPI President & CEO position which will be eliminated.)

(b) Yes. Although the Applicant cannot be specific about individual employees' positions being made redundant at this point, the Applicant intends to outline the plans for employees of the amalgamating LDCs at a high level in the Phase 2 application.

(c) The Applicant does not anticipate that the Phase 1 transaction will result in any material changes to the roles and responsibilities of existing WPI or EPC staff, particularly those positions directly responsible for the safe operation, maintenance, service quality and reliability of the distribution systems.

Following completion of Phase 1, WPI and EPC will continue to operate as separate licensed electricity distributors with separate distribution systems, operating centres, control room functions, field operations, engineering, maintenance, asset management, customer service and regulatory obligations.

The Applicant's intent during Phase 1 is to maintain "business as usual" operations while establishing common corporate ownership and governance. Accordingly:

- Existing operational and field staff at both WPI and EPC will continue to perform their current roles and responsibilities, while sharing best operating practices.
- Staff responsible for distribution system operations, maintenance, outage response, vegetation management, engineering, system planning, asset management and reliability will remain in place and continue to support their respective service territories.
- Existing operational procedures, emergency response practices, reliability

programs and maintenance activities will continue, with a view to exchanging best practices between the two utilities.
- Customers will continue to receive service from their existing utility under its existing distribution licence, with no changes to day-to-day utility operations resulting from Phase 1.

Staff-8

Reference

Financial Statements
Ref 1: WPI MAADs Application, p. 33 Ref 2:
WPI MAADs Application, p. 32

Preamble:
Audited financial statements for 2025 were not available for ERTH Power Corporation and WPI at the time of filing the Application.
Reference 2 states "CIBC will be preparing an annual covenant waiver for WPI's auditors with respect to the preparation of its audited 2025 financial statements. This waiver will be filed with the Board once it is received."

Questions

(a) Please file the 2025 audited financial statements for each utility.
(b) Please file the waiver noted in reference 2.

Responses

(a) Please see Exhibit Staff-8(a).

(b) Please see Exhibit Staff-8(b).

Staff-9

Reference

Affiliate Matters
Ref 1: WPI MAADs Application, p. 23
Ref 2: WPI MAADs Application, pp. 10-11 Ref 3:
WPI MAADs Application, p. 30

Preamble:
Reference 1 states that if this Application is approved, all utilities owned by ERTH Corporation, including ERTH Power Corporation and WPI, receive shared common corporate and financial oversight from ERTH Corporation pursuant to Affiliate Relationships Code

compliant services agreements.
Reference 2 identifies the business of the Applicant's affiliates.
Reference 3 states that the core strengths of ERTH Power Corporation and ERTH Corporation in community building, reliability, safety, operations, customer service, and solid financial performance will be leveraged by WPI through one integrated management team and board of directors. The anticipated savings will be passed on to customers through lower OM&A costs after Phase 2 of the transaction.

Questions

(a) Please fully describe the extent to which EWAI foresees the new Westario Power utilizing the services of the affiliates identified in the Application post Phase 1. As part of the response, please populate the following tables to depict the expected future services received / provided.
(b) Given the excerpt noted in the preamble from reference 3, please specifically explain how compliance with 2.1.2 of the *Affiliate Relationships Code*, which requires that a utility ensure that at least one-third of its Board of Directors is independent from any affiliate, will be achieved.
(c) Please explain how ERTH Corporation will ensure there is no cross-subsidization between customers of WPI, ERTH Power Corporation, and THI.

Responses

(a) Following Phase 1, the new WPI will utilize the shared corporate services that ERTH Corporation and ERTH (Holdings) Inc. currently provides EPC, which is reflected in the table below.

Shared Services

Name of Company		Service Offered
From	To	
ERTH (Holdings) Inc.	Westario Power Inc.	Information management services, information technology services.

Corporate Cost Allocation

Name of Company		Service Offered
From	To	
ERTH Corporation	Westario Power Inc.	Strategic management and policy support, legal services, building support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, public affairs.

(b) The reference above to one integrated management team and board of directors

relates to the management team and board of directors at ERTH Corporation. During Phase 1, EPC, WPI and THI will each maintain separate boards of directors which will each maintain a minimum level of at least one-third board independence. EPC's board of directors currently consists of fifty percent (50%) independent directors, and the Applicant intends to employ the same approach for WPI and THI to ensure compliance with section 2.1.2 of the *Affiliate Relationships Code*.

(c) EPC, WPI and THI will be operated as separate stand-alone entities following the Phase 1 transaction and, accordingly, there will be no cross-subsidization between the three utilities. The relationship between the utilities will be closely monitored, however, and if one utility provides services or goods to another utility, the appropriate pricing, tendering, and other requirements in the ARC will be satisfied.

Staff-10

Reference

Cost Savings
Ref 1: WPI MAADs Application, pp. 23-24 Ref 2:
WPI MAADs Application, Table 5

Preamble:
The Application states that although the Phase 1 transaction will result in moderate transaction and transition costs, as well as management fees payable to ERTH Corporation, these additional WPI costs will be offset by the modest cost savings for WPI described.

Question

(a) Please confirm if the WPI synergies included in Table 5 are net of transaction and transition fees, as well as management fees payable to ERTH Corporation (pp. 23-24). If not, please explain and confirm if net synergies are still anticipated once all noted costs are considered.

Response

(a) Confirmed.

Staff-11

Reference

Comparative Forecasted Revenue Requirement Analysis Ref 1: WPI MAADs Application, pp. 23-25, Tables 5 and 6 Ref 2: WPI MAADs Application, p. 21

Preamble:

Table 5 of the Application provides the forecasted revenue requirements for each of WPI and ERTH Power Corporation for each year between 2026 and 2035 under post- consolidation and status quo scenarios. Table 6 outlines the assumptions regarding inflation, growth and productivity included in the analysis.

At reference 2, the Applicant requests that following Phase 1, WPI and ERTH Power be permitted to continue to operate as independent utilities until the Phase 2 application is filed.

Questions

(a) Please explain why the difference in revenue requirement in the "post transaction" scenario is greater than the synergies achieved beginning in 2029.
(b) Please explain why the "no transaction" scenario in Table 5 does not include a rebasing application post 2029 for WPI, and post 2028 for ERTH Power Corporation.
(c) Please confirm if Table 5 needs to be updated to reflect EWAI's response to OEB Staff-5 seeking clarification of various timelines.
(d) Please confirm OEB staff's understanding that the synergies listed in Table 5 are solely OM&A-related.
    i. If yes, please describe any capital savings that are anticipated following the Phase 1 transaction. If none are expected as part of Phase 1, please explain why not.
    ii. Are there capital-related synergies anticipated as part of the Phase 2 transaction? If yes, please describe. If not, please explain why not.
(e) Please confirm if, for each year under the Phase 1 transaction in both the "no transaction" and "transaction" scenarios, the utility specific stretch factor for each of WPI and ERTH Power Corporation was utilized. OEB staff observes that in Table 6 there is a combined stretch factor listed for these years (in addition to utility specific stretch factors for WPI and ERTH Power Corporation), but it is unclear what stretch factor is utilized in the analysis.
    i. If a combined stretch factor was used for any of the years under Phase 1, please explain why given the proposal in reference 2 (i.e., that WPI and ERTH Power be permitted to continue to operate as independent utilities until Phase 2). OEB staff notes that as per the PEG Report to the OEB[3], WPI is in Group 2, and ERTH Power Corporation is in Group 3.
(f) Please re-file Tables 5 and/or 6 based on the responses to the above questions, if required. Please also include any updated commentary, if required, regarding updated figures / results in the status quo and post-consolidation scenarios.

Responses

(a) The apparent variance between the revenue requirement in the "post-transaction" scenario and the synergies realized beginning in 2029 is attributable to the differing rebasing assumptions in the two scenarios. Under the "no transaction" scenario, WPI rebases its rates in 2029, resulting in an increase in its revenue requirement. Under

the "post-transaction" scenario, however, WPI does not rebase in 2029 because its rates remain subject to the proposed deferred rebasing period following the transaction. Consequently, beginning in 2029, the revenue requirement in the "post-transaction" scenario exceeds the annual synergies realized, notwithstanding the continued achievement of merger-related efficiencies.

(b) The "no transaction" scenario in Table 5 does not include a rebasing application post 2029 for WPI, and post 2028 for ERTH Power Corporation due to an oversight. An updated Table 5 is set out in response to Staff-11(f) below.

(c) Confirmed. Please see response to Staff-11(f) below.

(d) Confirmed.

i. No capital savings are anticipated following the Phase 1 transaction. WPI recently filed an approved Distribution System Plan ("DSP") as part of its 2024 COS application and, as a condition of the proposed transaction, the Applicant has agreed to continue to invest in the WPI system pursuant to the approved DSP. The approved DSP runs through 2028 and, as such, there are no synergies as part of Phase 1 related to capital expenditures.

ii. Yes, there are capital-related synergies anticipated as part of the Phase 2 transaction. The extent of these synergies has not been identified and will be detailed in the Phase 2 application.

(e) The utility specific stretch factor for each of WPI and EPC was utilized for each year under the Phase 1 transaction in both the "no transaction" and "post-transaction" scenarios. However, there was a cell reference error for EPC in Table 5 included with the original WPI application.

i. A combined stretch factor was not utilized.

(f) An updated Table 5 is set out below.

Revenue Requirement - No Transaction										
(dollars in thousands)	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	IRM	COS	IRM	IRM	IRM	IRM	COS	IRM
WPI	$ 14,568	$ 15,284	$ 15,486	$ 18,583	$ 19,650	$ 19,910	$ 20,174	$ 20,442	$ 23,509	$ 24,534
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	COS	IRM	IRM	IRM	IRM	COS	IRM	IRM
EPC	$ 17,766	$ 18,388	$ 23,132	$ 24,105	$ 24,460	$ 24,784	$ 25,113	$ 28,879	$ 30,138	$ 30,537
ICM	$ 2,317	$ 2,317								
No Transaction Total	**$ 34,651**	**$ 35,989**	**$ 38,618**	**$ 42,688**	**$ 44,109**	**$ 44,694**	**$ 45,287**	**$ 49,322**	**$ 53,647**	**$ 55,071**

Revenue Requirement - Phase 1 and Phase 2 Transactions	Yr Phase 1 MAADs			Yr 4 Phase 2 MAADs						
(dollars in thousands)	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM
WPI	$ 14,568	$ 15,284	$ 15,486	$ 15,608	$ 15,815	$ 16,025	$ 16,238	$ 16,455	$ 16,675	$ 16,898
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	COS	IRM	IRM	IRM	IRM	IRM	IRM	IRM
EPC	$ 17,766	$ 18,388	$ 23,132	$ 24,105	$ 24,460	$ 24,784	$ 25,113	$ 28,879	$ 30,138	$ 30,537
ICM	$ 2,317	$ 2,317								
Synergies	-$ 20	-$ 50	-$ 54	-$ 48	-$ 55	-$ 338	-$ 346	-$ 354	-$ 362	-$ 371
Transaction Total	**$ 34,631**	**$ 35,938**	**$ 38,564**	**$ 39,665**	**$ 40,220**	**$ 40,471**	**$ 41,005**	**$ 44,981**	**$ 46,451**	**$ 47,064**

Staff-12

Responses

Comparative Forecasted Revenue Requirement Analysis
Ref 1: MAADs Handbook, Schedule 2 Filing Requirements, pp. 9-10 Ref 2: WPI MAADs Application, pp. 23-25

Preamble:

The Filing Requirements state:

Provide a statement confirming that at the time of the post consolidation rebasing application, the consolidated entity will produce an updated analysis comparing the revenue requirement (under both the consolidated scenario and the status quo) but based on information available on a reasonable efforts basis. Further, provide a statement confirming that this will be supplemented with a comparison and discussion of the consolidation application forecasts versus those filed in the post-consolidation rebasing application.

Question

(a) Please confirm that at the time of the post consolidation rebasing application, the consolidated entity will produce an updated revenue requirement analysis which will be supplemented with a comparison and discussion of the consolidation application forecasts versus those filed in the post-consolidation rebasing application.

Response

(a) Confirmed.

Staff-13

Reference

OM&A Savings and Analysis
Ref: WPI MAADs Application, Table 7, p. 25

Preamble:
OEB staff has reproduced Table 7 below.

OM&A Costs (dollars in thousands)	Phase 1			Phase 2	Post Consolidation Period					
	Yr 1 - 2026	Yr 2 - 2027	Yr 3 - 2028 EPC Test Year	Yr 4 2029 MAADs Application	Yr 5 - 2030	Yr 6 - 2031	Yr 7 - 2032	Yr 8 - 2033	Yr 9 - 2034	Yr 10 - 2035
EPC	$ 11,103	$ 11,252	$ 11,388	$ 11,728	$ 12,052	$ 12,413	$ 12,786	$ 13,169	$ 13,564	$ 13,971
WPI	$ 8,381	$ 8,591	$ 8,806	$ 9,026	$ 9,251	$ 9,483	$ 9,720	$ 9,963	$ 10,212	$ 10,467
EPC + WPI	$ 19,484	$ 19,842	$ 20,193	$ 20,753	$ 21,303	$ 21,896	$ 22,506	$ 23,132	$ 23,776	$ 24,438
WPI Synergies	-$ 20	-$ 50	-$ 54	-$ 48	-$ 55	-$ 338	-$ 346	-$ 354	-$ 362	-$ 371
Forecasted OM&A	$ 19,464	$ 19,792	$ 20,139	$ 20,706	$ 21,248	$ 21,558	$ 22,160	$ 22,778	$ 23,414	$ 24,068
OM&A / Customer										
EPC	$ 444.85	$ 441.98	$ 447.33	$ 460.69	$ 418.42	$ 424.52	$ 436.37	$ 448.55	$ 461.07	$ 473.94
WPI	$ 337.56	$ 346.00	$ 354.65	$ 363.51						

Questions

(a) Please provide 2025 actual OM&A costs per customer for each of ERTH Power Corporation and WPI.
(b) Please provide an explanation as to how the Applicant forecasted the OM&A for each utility on a standalone basis for year 1 and the growth for each subsequent year.
(c) Please explain all material assumptions made with respect to the forecasted OM&A cost savings.
(d) Please provide a breakdown of the OM&A cost savings indicating which are attributable to the following categories: administrative, governance, information technology, regulatory, finance, legal or other (please specify).

Responses

(a) The 2025 actual OM&A costs per customer for each of EPC and WPI are set out below:

OM&A Costs (dollars in thousands)	2025
EPC	$ 9,548
WPI	$ 9,143
EPC + WPI	$ 18,691
Synergies	
Forecasted OM&A	$ 18,691
OM&A / Customer	
EPC	$ 377.56
WPI	$ 365.84

(b) The Applicant forecasted OM&A expenses for each utility on a stand-alone basis using each utility's approved Year 1 budget. For subsequent years, WPI's OM&A was escalated by an annual growth factor of 2.5%, while EPC's approved five-year budget forecast was applied through 2030, after which an annual growth factor of

3.0% was applied

(c) The Applicant projected cost savings based on the applicable 2026 budgeted costs associated with the identified synergy initiatives. Those costs were escalated by an annual inflation factor of 3.0% in each subsequent year of the analysis.

(d) A detailed description of the identified synergies is provided in the Applicant's response to WPI-PP-23. The identified synergies are limited in number and value and, accordingly, the Applicant has not broken out the identified synergies into the itemized detail requested in Staff-13(d) and the requested information is not available.

Staff-14

Reference

Service / Operations Centre
Ref 1: WPI MAADs Application, p. 29 Ref 2:
WPI MAADs Application, p. 18

Preamble:

At reference 1, it is noted that the current operation centres will be maintained in the WPI and ERTH Power Corporation territories throughout the duration of the Phase 1 transaction. During Phase 2 and beyond, the main headquarters are expected to be ERTH Power Corporation's new office and operations centre in Ingersoll approved by the OEB in EB-2024-0021. Functions such as engineering, procurement, human resources, finance, legal, regulatory, information technology, and customer service will be administered and delivered from the Ingersoll location, with each location having operations staffing similar to current resourcing levels.

Reference 2 states that the parties to the proposed transaction have agreed to a number of post closing covenants. One of the items is an obligation to maintain Westario Power's administration and operations facility for 10 years.

Questions

(a) Please explain how successful coordination between the administration/operations centre of WPI and ERTH Power Corporation will be ensured, both post Phase 1 and post Phase 2 (if approved by the OEB), given that the service area boundaries of each utility are not contiguous.

(b) A portion of reference 1 indicates that during Phase 2 and beyond, customer service will be administered and delivered from ERTH Power's Ingersoll location. Please further clarify if and how any customer service functions that are currently administered at WPI's current location will change post Phase 1 vs. post Phase 2.

i. Will there be any effect on the availability of services provided to WPI

customers in the physical WPI service area?

Responses

(a) The Applicant and EPC have a successful 26-year history of managing non-contiguous service territories with multiple administration/operations centres. For example, EPC continues to successfully coordinate with an operations centre in the Town of Goderich, among others, following the acquisition of West Coast Huron Energy Inc. and its subsequent merger with EPC (EB-2018-0082). The Applicant proposes to deploy the same steps to ensure that successful coordination with the administration/operations centre in the Town of Walkerton.

(b) The customer service functions that are currently administered at WPI's current location will not change post Phase 1. The details regarding which customer service functions may be moved to ERTH Power's Ingersoll location post Phase 2 have not been finalized and they will be addressed in the Phase 2 application.

i. There will be no change in the availability of services provided to WPI customers in the physical WPI service area.

Staff-15

Reference

Service Quality Statistics
Ref 1: WPI MAADs Application, p. 26
Ref 2: WPI MAADs Application, Appendix E, Scorecards of WPI and EPC [PDF p. 249]

Preamble:
Reference 1 states "Throughout both phases of this transaction, it is the intention of the Applicant to maintain the service levels of WPI through the merging of technologies, system control, adoption of best work practices, etc."
Based on the 2024 OEB Scorecards provided in the Application at reference 2, OEB staff has summarized the Customer Focus metrics for WPI and ERTH Power Corporation. OEB staff has highlighted certain results where WPI has achieved results slightly higher than ERTH Power Corporation.

		2020		2021		2022		2023		2024	
		Westario Power	ERTH Power	Westario Power	ERTH Power	Westario Power	ERTH Power	Westario Power	ERTH Power	Westario Power	ERTH Power
	New Residential/Small Business Services Connected on Time	95.43%	98.59%	96.24%	95.84%	100.00%	97.05%	100.00%	95.76%	100.00%	95.11%

Service Quality	Scheduled Appointments Met on Time	97.33%	100.00%	99.52%	99.06%	99.89%	100.00%	99.89%	99.18%	99.58%	99.53%
	Telephone Calls Anwered on Tine	86.73%	95.92%	88.45%	95.02%	86.03%	92.54%	87.42%	93.49%	86.84%	86.49%
Customer Satisfaction	First Contact Resolution	98.19%	99.58%	98.83%	99.26%	99.01%	99.43%	99.01%	99.66%	99.04%	99.91%
	Billing Accuracy	99.61%	99.75%	99.78%	99.85%	99.81%	99.62%	99.54%	99.69%	99.81%	97.01%
	Customer Satisfaction Survey Results	94.00%	77.00%	94.00%	77.00%	94.00%	76.00%	93.00%	76.00%	93.00%	76.00%

Questions

(a) Please provide 2025 results for WPI and ERTH Power Corporation.
(b) Please more fully describe how, at a minimum, current service levels of WPI will be maintained. As part of the response, please provide examples as to where / how service levels will be maintained and / or improved "through the merging of technologies, system control, adoption of best work practices." As part of the response, please also specifically discuss how the two metrics highlighted by OEB staff will be, at minimum, maintained for WPI.

Responses

(a) The 2025 results for WPI and EPC are set out below:

Year	Commercial Services connected On-Time (Target:90%)		Scheduled Appointments met On-Time (Target: 90%)		Telephone Calls Answered On-Time (Target :65%)		First Contact Resolution		Billing Accuracy (Target:90%)		Customer Satisfaction Survey	
	EPC	WPI	EPC	WPI	EPC	WPI	EPC	WPI	EPC	WPI	EPC	WPI
2025	95.37%	100.00%	99.55%	99.73%	88.03%	86.84%	100.00%	99.07%	98.30%	99.72%	89.00%	93.00%

(b) The Applicant's intent during Phase 1 is to maintain "business as usual" operations while establishing common corporate ownership and governance. Accordingly, existing customer services, operational and field staff at WPI will continue to perform their current roles and responsibilities, which is expected to maintain the two metrics highlighted by OEB staff. Moreover, the Applicant is optimistic that the following examples of "the merging of technologies, system control, adoption of best work practices" may improve WPI's current services levels:

- The sharing of engineering and operational knowledge and expertise between WPI and EPC, which will lead to higher quality operations and maintenance plans that will benefit customers of both WPI and EPC;
- Access to EPC's knowledge and expertise in SCADA (Supervisory Control & Data Acquisition) systems, improving response times and troubleshooting efforts;
- Extension of the ERTH social media platforms (Twitter, Facebook, LinkedIn) to include WPI to aid in the promotion of distributor activities, engagement of

customers, and communication of outage information;

- WPI will have access to expanded ERTH corporate services; and
- Emergency storm response resources will improve as WPI will have access to ERTH's larger pool of power line maintainers, inventory and equipment (which will be shared in accordance with the *Affiliate Relationships Code*).

Staff-16

Reference

Incremental Transaction and Transition Costs Ref: WPI
MAADs Application, pp. 30-31

Preamble:
The Application states that,

- *Incremental one-time transaction and transition costs are expected to be approximately $800k and will not be funded by ratepayers.*
  - *Incremental transaction costs include but are not limited to due diligence on the part of all parties, the costs associated with negotiating the terms of the purchase, costs associated with all regulatory, legal and statutory reviews to receive necessary regulatory approvals and internal resources.*
  - *Incremental transition costs that are expected as a result of the Phase 2 transaction include information technology, legal, and professional advisory services.*
- *Integration costs will be financed through the anticipated productivity savings expected from the transaction during the period after the Phase 2 transaction. These costs are primarily related to transition planning and execution, IT costs, communication costs, workforce training (p. 31).*

Questions

(a) Please clarify if the $800k includes transaction and transition costs relating to the Phase 1 transaction, the Phase 2 transaction, or both.
   i. If any of the costs relate to both Phase 1 and Phase 2, please clarify how much relate to each transaction / provide an estimated apportionment.
   ii. If any of the costs in Phase 1 are related to Phase 2, please comment on whether it is necessary to incur those costs during Phase 1, given that the Phase 2 application will be filed at a later date.

(b) Please clarify who will pay the incremental one-time transaction and transition costs and where the money will come from.

(c) Do the $800k transaction and transition costs include the "integration costs" noted in the preamble (bullet point 3), or are these separate costs?
   i. If these are separate, please provide forecasts for all integration costs associated

with the proposed transaction broken down by category and by year in which the costs are expected.

ii. To the extent that there are any transition (integration) costs prior to Phase 2, how does the Applicant expect these costs to be financed in the interim given that "costs will be financed through the anticipated productivity savings expected from the transaction during the period after the Phase 2 Transaction."

(d) If synergies and cost efficiencies do not materialize as expected, how does the Applicant plan to address any financial viability issues that may occur?

Responses

(a) Based on the definitions in the MAADs Handbook,[7] the $800k includes incremental transaction costs relating to the Phase 1 transaction only. The Applicant interpreted transition costs incorrectly in the WPI Application and it submits that there will be no transition costs associated with Phase 1. The incremental transaction and transition costs related to the Phase 2 transaction (i.e. information technology, legal, and professional advisory services related to consolidating the three utilities) will be detailed in the Phase 2 application.

i. Not applicable.

ii. Not applicable.

(b) The Applicant will pay for the incremental one-time transaction and transition costs. Neither WPI nor EPC will pay for any incremental one-time transaction and transition costs. The $800k of Phase 1 transaction costs will be funded via ERTH Corporation's existing credit facility with its lender or retained cash.

(c) The $800k transaction do not include the "integration costs" noted in the preamble (bullet point 3).

i. The "integration costs" are detailed in the Applicant's responses to Staff-41(b) and WPI-PP-23 .

ii. To the extent that the above costs or any transition or integration costs arise prior to Phase 2, the Applicant submits that these costs will be financed in the interim via ERTH Corporation's existing credit facility with its lender or retained cash.

(d) The Applicant submits that the failure to recognize synergies and cost efficiencies

[7] MAADs Handbook, Section 4.3, page 13.

following Phase 1 transaction will have no impact on the financial viability of the stand-alone utilities (who will bear no transaction or transition costs associated with the Phase 1 transaction and will continue to operate as per usual.)

For the purposes of obtaining the financing approval to acquire WPI described in Section 4.2(iv) of the WPI Application, ERTH Corporation forecasted financial results with no synergies or cost efficiencies as a worst-case scenario. ERTH's lender (Scotiabank) is aware and supportive of a Phase 1 transaction that may not include synergies or cost efficiencies.

Accordingly, the Applicant submits that there will be no financial viability concerns if synergies and cost efficiencies do not materialize as expected.

Staff-17

Reference

Purchase Price
Ref 1: WPI MAADs Application, pp. 18-19, 31
Ref 2: WPI MAADs Application, Appendix C – Share Purchase Agreement

Preamble:

The Share Purchase Agreement notes that the aggregate purchase price is $112,529,875, which is equal to an amount obtained by multiplying 1.45 by the Estimated 2025 Rate Base, subject to the adjustments and conditions described in the Share Purchase Agreement. The "Estimated 2025 Rate Base" is $77,610,000.
The closing of the acquisition of the Purchased Shares is conditional upon the receipt of all required approvals, including the OEB's approval of this Application.

Questions

(a) Please explain "all required approvals" other than the OEB approval of this Application.
(b) Please confirm if an acquisition premium is being paid in the purchase price of the proposed transaction.
    i. If yes, please confirm the Applicant's understanding that, per the MAADs Handbook, if a premium has been paid above the historic value of assets, that purchase price premium is not recoverable through distribution rates.
(c) Please confirm that the post closing adjustments are not expected to be material and will not affect ERTH Corporation's financial liability or financing circumstances.

Responses

(a) The "required approvals" are described in the closing conditions contained in

Sections 5(c) and 6(b) of the WPI MAADs Application, Appendix C – Share Purchase Agreement.

(b) Confirmed.

i. Confirmed.

(c) Confirmed.

Staff-18

Reference

Financing
Ref: WPI MAADs Application, pp. 32-33

Preamble:
The Application states that the estimated purchase price is not expected to have a material impact on the overall financial viability of EWAI's parent company, ERTH Corporation, or any of its affiliates. If Phase 1 is completed, WPI will represent approximately 45% of the total assets of ERTH Corporation.
Further, the proposed transaction will be 100% financed by new debt issued to ERTH Corporation. Upon completion of the Phase 1 transaction, ERTH will be deploying a plan to transition the LDCs to a 70:30 debt/equity ratio.

Questions

(a) Please describe any expected impacts on the future rates of ERTH Corporation's acquired distributors caused by costs associated with the proposed transaction.
(b) Please confirm if the "45% of total assets" statistic includes the proposed acquisition of THI. If not, please provide an updated percentage.
(c) Please provide more detail on the arrangements / terms and conditions of the loan, including but not limited to, the repayment term of the loan, interest rate (fixed/variable), collateralized assets, debt covenants imposed, etc.
    i. For any debt covenants of the loan, please comment on ERTH Corporation's ability to meet those covenants, and the ramifications of violating these covenants with specific reference to the financial viability of ERTH Corporation and / or WPI.

Responses

(a) There are no expected impacts on the future rates of ERTH Corporation's acquired distributors caused by costs associated with the proposed transaction

(b) The "45% of total assets" statistic did not include the proposed acquisition of THI. With THI included, WPI will represent approximately 38% of the total assets of ERTH Corporation.

(c) The WPI transaction will be 100% financed by new debt issued to ERTH from Scotiabank, and ERTH has negotiated financial terms with Scotiabank that recognizes the financial circumstances of WPI after the Phase 1 transaction. The financing commitment letter currently being contemplated by the parties reflects the following terms:

- Variable interest rate (bank's prime lending rate from time to time, less 0.30% per annum with interest payable monthly)
- Advances are interest only and paid monthly with the outstanding balance repayable in full on or before the maturity date
- The term of the loan is 5 years
- Excluding the utilities owned by ERTH Corporation, a General Security Agreement from ERTH Corporation and its affiliates over all present and future personal property with appropriate insurance coverage, loss if any, payable to the Bank
- Pledge/assignment of 100% of the shares of ERTH's utilities
- Guarantee from ERTH's utilities limited to 25% of the utilities' equity
- Debt covenants include: (i) 75 : 25 debt-to-capital ratio, (ii) 1.20 : 1 interest coverage ratio, (iii) 1.50 : 1 EBITDA / (Interest + Current Portion of LTD + Capital Leases), and (iv) 0.70 : 1 Funded Debt + Standby L/Cs / Capitalization.

i. The Applicant has developed a five-year financial forecast that assumes no transaction-related synergies are realized. This conservative downside-case scenario has been shared with Scotiabank and the parties are confident that ERTH Corporation will comply with the anticipated financial covenants contemplated under the proposed financing arrangements throughout the forecast period. Accordingly, ERTH does not anticipate that the proposed financing arrangements will adversely affect the financial viability of either ERTH Corporation and/or WPI.

If ERTH Corporation violates these covenants, and the bank fails to grant a waiver, the ramifications typically include increased interest rates and administrative fees, refusal of further advances, accelerate the debt, or enforce the security described above. The Applicant notes that these consequences are consistent with the ramifications associated with failing to meet debt covenants

under ERTH Corporation's and WPI's current debt facilities and, accordingly, it submits that debt covenant breaches are not materially different under either the status quo or proposed transaction scenarios.

Staff-19

Reference

Post Consolidation Monitoring and Reporting Ref 1:
WPI MAADs Application, p. 35
Ref 2: MAADs Handbook, pp. 33-35

Preamble:

The Applicant states a mid-term report for WPI will be filed given that it is deferring rebasing for more than five years. The mid-term report will contain the required components as set out in the Post-Consolidation Monitoring and Reporting section of the MAADs Handbook. The Applicant also confirms that in its first rebasing application updates to the mid term report will be provided for any period not included in that report.

Questions

(a) Please confirm the year that the mid-term report will be filed.
(b) Please confirm if the mid-term report proposed as part of this Phase 1 Application will detail the required components solely as it relates to WPI. If not, please explain.
(c) If the OEB approves the Phase 1 and Phase 2 transactions, how does the Applicant intend to report on the required components as set out in the Post- Consolidation Monitoring and Reporting section of the MAADs Handbook following Phase 2 and at the time of the rebasing of the consolidated entity? Please clarify the proposal with respect to post consolidation reporting.

Responses

(a) The Applicant plans to mid-term report will be filed in 2031.

(b) Confirmed.

(c) Following Phase 2, the Applicant intends to report on the required components set out in the Post-Consolidation Monitoring and Reporting section of the MAADs Handbook together as a consolidated entity. Currently, the Applicant plans to submit a mid-term report that includes the following information, collected on a reasonable efforts basis:

- Progress to date on (i) the various activities where efficiencies were expected, (ii) the savings achieved associated with those efficiencies, and (iii) the

recovery of transaction and transition costs will be reported using the table set out below:

Activity	Expected Efficiencie	Actual Efficiencies	Realized Savings
Activity 1			
Activity 2			
Activity 3			
		Total Savings:	
		(Transaction Costs)	
		(Transition Costs)	
		NET RESULTS	

- A qualitative discussion on enhanced reliability and service quality as a consolidated distributor and on a rate zone basis.
- A discussion on potential obstacles going forward in reaching the consolidated entity's targets as set out in the consolidation application, if any.
- An updated revenue requirement analysis as provided in the consolidation application based on information known at the time of the filing of the mid-term report, and a variance analysis to explain material differences to what was filed in the consolidation application will be reported using the table set out below:

Revenue Requirement Analysis (Application)	Revenue Requirement Analysis (Updated)	Variance	Analysis
Item 1			
Item 2			
Item 3			

Staff-20

Reference

Reliability Reporting
Ref: WPI MAADs Application, pp. 21, 35

Preamble:
The Application states that WPI and ERTH Power Corporation will continue to report separately.
ERTH Corporation will file Phase 2 of the transaction for approval by OEB to allow for the amalgamation of ERTH Power Corporation, WPI, and THI.
*The Application states that **during the proposed deferred rebasing period** (emphasis added by OEB staff), WPI will continue to report system level reliability as part of its annual RRR filings to the OEB.*

Questions

(a) Please clarify whether, as part of this Application, the Applicant is proposing that WPI

continue to report system level reliability separately to the OEB for the entirety of the proposed deferred rebasing period (i.e., 9 years), or will a separate proposal be brought forth in Phase 2 regarding reliability reporting for the consolidated entity (or the legacy utilities within the consolidated entity)?

i. Please provide further supporting rationale for the proposal.

(b) Please provide further information on the anticipated post consolidation reliability reporting at the time of the Phase 2 application which will seek to combine the service areas to be served by a single merged utility. For example, will each utility continue to report system level reliability separately until the combined entity rebases as one?

Responses

(a) A separate proposal will be brought forth in the Phase 2 application regarding reliability reporting for the consolidated entity (or the legacy utilities within the consolidated entity).

i. The Applicant will continue to have the ability to separately track reliability for WPI and the other legacy utilities (based on feeder and service community) following Phase 2, and it will be prepared to report the same in Reporting and Record-keeping Requirements ("RRR") filings or otherwise.

(b) Following Phase 2 and until the combined entity rebases as one., it is not expected that the merged entity will report separate reliability reporting, however New EPC will have the ability to track and report segmented (e.g. separated by rate zones) reliability statistic in its midterm and final report as part of its harmonizing rate application.

Staff-21

Reference

SAIDI / SAIFI
Ref 1: WPI MAADs Application, Table 8, p. 27
Ref 2: WPI MAADs Application, Appendix E – 2024 Scorecards of WPI and EPC

Questions

(a) Please provide 2025 SAIDI / SAIFI results.

(b) A review of ERTH Power Corporation's 2024 Electricity Utility Scorecard indicates that ERTH Power Corporation's System Reliability metrics did notmeet the most recent OEB targets. Westario Power's System Reliability metrics exceeded OEB targets. How will ERTH Corporation ensure that the issues affecting this metric within ERTH Power Corporation's service area (and control) do not transition to the customers of Westario

Power or downgrade the reliability indices for Westario Power customers?

Responses

(a) The 2025 SAIDI / SAIFI results for WPI and EPC are set out below:

Westario	2025
SAIDI	1.00
SAIFI	0.55
ERTH	2025
SAIDI	1.67
SAIFI	0.28

(b) While, at first glance, ERTH Power's historical system reliability performance may appear to be less favourable than WPI's, this comparison does not account for the utilities' respective distributor-specific performance targets. EPC's distributor-specific targets are significantly more stringent, with SAIDI and SAIFI targets of 0.91 and 0.39, respectively, compared to WPI's targets of 1.64 and 0.57. Over the five-year period reported in their respective 2024 OEB Scorecards, EPC recorded average SAIDI and SAIFI results of 1.34 and 0.55, while WPI recorded 1.65 and 0.61.

The Applicant further submits that the proposed transactions are not expected to adversely affect system reliability. During Phase 1, WPI will continue to operate as it does today, maintaining its existing operations centre, outage response processes, and field resources. ERTH Corporation has consistently demonstrated a strong commitment to system reliability and outage response and intends to apply the same operational focus and performance culture across the combined organization.

The Applicant also notes that, based on 2024 performance, both utilities performed better than the provincial average. WPI ranked 19th among Ontario distributors for SAIFI, with a result of 0.57, while EPC ranked 25th with a result of 0.76, compared to the provincial average of 1.21. For SAIDI, WPI ranked 34th with a result of 1.19 and EPC ranked 37th with a result of 1.51, both outperforming the provincial average of 1.57. These results demonstrate that both utilities currently deliver system reliability that exceeds the average performance of Ontario electricity distributors.

Staff-22

Reference

Key Systems
Ref 1: WPI MAADs Application, section 4.1, pp. 23-25 Ref 2: WPI MAADs Application, Table 5

Preamble:
The Application states that the comments and tables in this section assumes that there is no need to replace any of the key systems identified in the WPI cost of service application during the applicable rate period (i.e. 2024-2028).

Questions

(a) Please itemize the "key systems identified" in the WPI cost of service application.
(b) If any of the key systems identified do need replacement during the applicable rate period, please explain the impact this would have on the synergies anticipated from the proposed Phase 1 transaction, and anticipated Phase 2 transaction.

Responses

(a) In the Applicant's opinion, the "key systems identified" in the WPI cost of service application include Customer Information System (CIS), billing system, AMI head-end systems, and Enterprise Resource Planning (ERP) software.

(b) The Applicant respectfully submits that this question is too speculative to answer. While an Incremental Capital Module application may be required if the applicable eligibility criteria are met, it is not possible at this time to determine, in the abstract, whether such an application would have any impact on the anticipated synergies arising from the proposed WPI transaction.

Staff-23

Reference

WPI 2026 IRM
Ref: Decision and Order, EB-2025-0002, section 7, pg. 7

Preamble:
In WPI's 2026 IRM application, OEB staff notes that the OEB approved interim disposition of the 2024 balances for Account 1588 and 1589, recognizing material settlement errors (i.e. $1,613,081) have been recorded in the 2024 balance for both accounts and the inherent inter-relationship between these two accounts. WPI stated that it is prepared to carry the balance forward and request final disposition in its next IRM application.

Questions

(a) Please clarify whether there are any cash flow impacts of the settlement errors identified in the 2026 IRM application on WPI.
   i. If so, please explain if and how the cash flow impact on WPI would impact the proposed merger in this application.

Responses

(a) Based on the settlement variances identified each month, there was a cash flow on WPI related to the impact of the settlement errors identified in the 2026 IRM application. Any outstanding amounts related to said settlement errors were fully settled with the IESO on October 7, 2025. The amounts above exclude any interest costs from additional credit line borrowings and related DVA impacts

   i. The above-described cash flow impact will have no impact on the proposed transaction in this Application.

Staff-24

Reference

Accounting treatment (WPI)

Questions

(a) Please describe any material differences in accounting policies or deferral and variance account treatment between EPC and WPI, including, but not limited to: capitalization policy, depreciation policy, and interest or carrying charge methodology of the DVAs.
   i. Please discuss any impacts on future consolidated reporting.
(b) Please confirm the regulatory accounting basis used for pension and OPEB expenses for EPC and WPI, i.e. accrual vs. cash basis.
   i. If the accounting basis differs between the two, please explain how the Applicant intends to harmonize these practices post-merger.

Responses

(a) There are no material differences in accounting policies or deferral and variance account treatment between EPC and WPI.

   i. Not Applicable.

(b) Both WPI and EPC leverage the cash basis for OPEB expenses.

   i. Not Applicable

Staff-25

Reference

ESM
Ref 1: Westario_ERTH _MAADs Application, p. 21 & 33
Ref 2: Handbook to Electricity Distributor and Transmitter Consolidations, July 11, 2024, section 5.1 & 5.6
Ref 3: Westario_ERTH _MAADs Application, Appendix H

Preamble:
*Per reference 1, the Applicant states that upon completion of the EPC CoS Application (and the acquisition of the Other LDC), ERTH will bring a second application to the Board to approve the second phase ("**Phase 2**") of the transaction to allow for the amalgamation of EPC, WPI, and the Other LDC under section 86(1)(c) of the OEB Act. The ultimate amalgamated entity will operate under the name ERTH Power Corporation ("**New EPC**").*
The Applicant requests the OEB's approval of a 9-year rate rebasing deferral period for WPI and proposes to implement earnings sharing mechanism ("ESM") for WPI (the "Westario ESM") for years six to nine of the rebasing deferral period.
OEB staff notes that the New EPC is the consolidated entity which will be established in Phase 2. It will be formed upon completion of the approved amalgamation of EPC, WPI, and the Other LDC.
Per reference 2, the OEB permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years.
Per reference 3, OEB staff also notes the ESM Deferral Account is proposed to be established under WPI instead of the New EPC.

Questions

(a) OEB staff understands that, following completion of Phase 2, EPC, WPI, and the Other LDC will amalgamate to form the New EPC.
   i. Please confirm whether the proposed nine-year deferral rebasing period is intended to apply to the amalgamated entity (New EPC).
   ii. If confirmed, please explain the rationale for applying a nine-year deferral rebasing period to WPI in Phase 1, while WPI is expected to cease to exist as a standalone distributor and become part of New EPC upon completion of Phase 2.
   iii. If this nine-year deferral rebasing period is not intended to apply to New EPC, please explain how the proposed deferral rebasing period would operate following the amalgamation of WPI into New EPC.

(b) Please confirm OEB staff's observations that the proposed ESM Deferral Account would be established for WPI rather than for New EPC.
   i. Please confirm whether the ESM Deferral Account is proposed to be established for WPI as a standalone entity.
   ii. If yes, please explain the rational for establishing the ESM Deferral Account for WPI, given that WPI is expected to amalgamate with EPC and the Other LDC to form New EPC during Phase 2.

iii. Please discuss whether establishment of the ESM Deferral Account under New EPC would be more appropriate following completion of the amalgamation. If not, please explain why not.
iv. Please comment on the appropriateness of calculating the ESM based on the weighted-average achieved ROE of the amalgamated utilities (i.e., EPC, WPI, and the Other LDC), and identify the proposed ESM effective period, including the commencement and end dates.
v. Please explain how any ESM balances would be tracked, reported, and transferred (if applicable) following the amalgamation into New EPC.

(c) Per reference 3, with respect to the disposition of ESM balances, please discuss:
i. When the Applicant proposed to calculate and report any ESM amounts during the deferral rebasing period.
ii. When and through what proceeding(s) the Applicant proposes to seek disposition of any non-zero ESM balances.

Responses

(a) The Applicant respectfully submits that the amalgamated entity ("New EPC") has not yet been established. In this application, the Applicant is seeking approval for a nine-year deferred rebasing period applicable to WPI. Upon completion of the Phase 2 amalgamation of WPI into New EPC, the Applicant intends to seek the OEB's approval for the balance of the deferred rebasing period then remaining to apply to the amalgamated entity.

i. Confirmed.

ii. The negotiated transaction involved the ratepayers of WPI receiving a nine-year rate deferral regardless of whether WPI remained as a stand-alone distributor. If the transferring the balance of the deferred rebasing period to New EPC is approved, the Applicant will establish a separate rate zone for WPI ratepayers in the same manner that it did in its acquisition and subsequent consolidation of West Coast Huron Energy Inc. (EB-2018-0082).

iii. Not applicable.

(b) The Applicant submits that the proposed ESM Deferral should be established for New EPC following Phase 2. During Phase 1, WPI will be operated separately, and New EPC will not have been established yet so there will be no merged entity to calculate the deferral account against.

i. See Staff-25(b) above.

ii. Not applicable.

iii. See Staff-25(b) above.

iv. The appropriateness of calculating the ESM based on the weighted-average achieved ROE of the amalgamated utilities and the proposed ESM effective periods will be addressed in the Phase 2 application.

v. The manner in which ESM balances will be tracked, reported, and balanced will be addressed in the Phase 2 application.

(c) Per reference 3, with respect to the disposition of ESM balances, please discuss:

i. The timing of calculating and reporting any ESM amounts during the deferral rebasing period will be addressed in the Phase 2 application.

ii. The manner in which the Applicant proposes to seek disposition of any non-zero ESM balances will be addressed in the Phase 2 application.

Staff-26

Reference

DVA
Ref 1: Westario_ERTH _MAADs Application, p. 33-36
Ref 2: Handbook to Electricity Distributor and Transmitter Consolidations, July 11, 2024, section 5.9, Tracking of Accounts

Preamble:
Per reference 1, the Applicant requests the OEB's approval of a 9-year rate rebasing deferral period for WPI during which it will operate under the OEB's Price Cap IR framework. With respect to timing of Group 2 disposition, the Applicant states that EPC will be filing its rebasing applications as scheduled and Westario has recently had its rebasing application approved. There will be no impacts to intergenerational inequity because of this Phase 1 application as EPC and Westario will be maintaining the same disposition schedule for these accounts.
The Applicant requests the OEB's approval to continue to track costs in the deferral and variance accounts currently approved by the OEB for WPI.
Per reference 2, utilities may gain efficiencies by tracking accounts on a consolidated basis, rather than a rate zone basis. Given the nature of the Group 1 accounts and the reliance on data from various systems (e.g., billing system), it is likely practical and efficient for utilities to consolidate the Group 1 accounts for new activities post-closing of the transaction. Therefore, for Group 1 accounts, the OEB encourages utilities to consolidate the accounts as soon as it is practical.

Questions

(a) Per reference 2, the OEB encourages utilities to consolidate the Group 1 accounts as soon

as it is practical, please explain the Applicant's proposed approach to the treatment of Group 1 accounts following Phase 1, including:

i. Whether and when the Applicant expects to consolidate the Group 1 accounts of WPI and EPC.
ii. If the Group 1 accounts will not be consolidated, the reasons why and how the Applicant proposes to address the OEB's expectation that Group 1 accounts be consolidated as soon as practical.

(b) For the request of approving to continue tracking costs in DVAs currently approved by the OEB, please clarify whether this request applies to:

i. Group 1 DVAs only; or
ii. Both Group 1 and Group 2 DVAs. Please provide supporting rationale.

(c) If the Applicant begins receiving a consolidated IESO invoice, please explain:

i. Whether separate Group 1 accounts balances for WPI and EPC can continue to be maintained;
ii. How any separate balances would be tracked and supported; and
iii. Whether the Applicant would consider consolidating the Group 1 accounts at that time rather than maintaining separate rate-zone-level accounts. If not, why not?

(d) Please confirm that EPC and WPI will continue to keep track and record the transactions separately for all Group 2 accounts during the post-amalgamation period, including Account 1592 sub-account CCA changes.

i. If not, please explain the proposed alternative approach.

(e) Please clarify when/which year WPI will seek disposition of Group 2 accounts.

i. If disposition is expected to occur more than five years after WPI's most recent rebasing application, please discuss the impact of intergenerational inequity and how the Applicant proposes to address them.

Responses

(a) Since EPC and WPI will continue to operate as stand-alone entities, any consolidation of Group 1 accounts will not occur until post Phase 2 as a minimum. The Applicant anticipates consolidation of Group 1 balances after Phase 2 once the utilities are operating with one distribution license and one IESO invoice.

(b) For the request of approving to continue tracking costs in DVAs currently approved by the OEB, this request applies to Group 1 and Group 2 DVAs because WPI will continue to operate separately with a separate IESO invoice which requires the Group 1 and Group 2 DVAs to be tracked independently of one another.

(c) Once the Applicant begins receiving a consolidated IESO invoice following Phase 2, Group 1 balances would be consolidated and, as such, separate balances would not be tracked or supported. The Applicant would consider consolidating the Group

1 accounts following the completion of Phase 2.

(d) Confirmed.

(e) The Applicant intends to dispose of its Group 2 Accounts prior to filing its harmonized Cost of Service application in 2035 in order to mitigate potential intergenerational inequity. The Applicant is also willing to consider any options or recommendations proposed by OEB Staff that would facilitate the timely disposition of these accounts.

Staff-27

Reference

Corporate Services
Ref 1: Westario_ERTH _MAADs Application, p. 27

Questions

(a) Please confirm whether ERTH Corporation or EPC provided any corporate services or oversight to WPI prior to the Phase 1 transaction. If so, please identify and describe all such services.

Responses

(a) Neither ERTH Corporation nor EPC provided any corporate services or oversight to WPI prior to the Phase 1 transaction.

Staff-28

Reference

Ref 1: Westario_ERTH _MAADs Application, p. 23

Preamble:
In the Reference above, the Applicant intends to eliminate the WPI President and CEO position and related costs.

Questions

(a) Please confirm whether there are any costs associated with eliminating the WPI President and CEO position.
(b) If yes, please provide the amount of these costs and confirm whether they are included in the one-time transaction or transition costs, and offset by the productivity savings.
(c) If these costs are not included in the transaction or transition costs, please indicate

who will be responsible for them.

Responses

(a) There are no costs associated with eliminating the WPI President and CEO position.

(b) Not applicable.

(c) Not applicable.

SECTION 2: ERTH/Tillsonburg Interrogatories

Section 2(a) – Energy Probe

EP-1

Reference

ERTH Corporation – Tillsonburg Hydro Inc., MAADs Application, Page 17

Preamble: "The parties have agreed to a number of post-closing covenants as set out in the Purchase and Sale Agreement, including:
a) all employees remain employed for three years …"

Questions

(a) Please confirm that Tillsonburg Hydro Inc. (THI) is a virtual utility and has no employees. All of THI's utility service work, including management, supervisions, operations, maintenance and administration is currently performed by employees of the Corporation of the Town of Tillsonburg (The Town of Tillsonburg).
(b) Is the plan to maintain arrangement described in question a above for three years or is it to transfer the individuals performing this work for THI to EARTH Power Corporation (EPC)?
(c) If the plan is to have the employees of the Town of Tillsonburg to continue to provide utility service work, will such work be provided by The Town of Tillsonburg to EPC under a services agreement? If the answer is yes, please file the services agreement if it is not already in evidence. If the answer is no, please explain why not.

Responses

(a) THI currently operates as a virtual utility. However, a process has been commenced pursuant to which all employees and assets related to THI's utility service work will be transferred from The Town of Tillsonburg to THI on or before the closing of the Phase 1 transaction.

(b) THI will operate as a stand-alone utility with its own employees, etc. and corporate and financial oversight from ERTH Corporation following the closing of the Phase 1 transaction.

(c) Not applicable.

EP-2

Reference

ERTH Corporation – Tillsonburg Hydro Inc., MAADs Application, Page 25

Preamble: "THI employees who are on call and live in or within close proximity to the Town of Tillsonburg will be permitted to take THI-owned work vehicles home allowing such employees to respond promptly to outages and other emergency situations without the need to return to an operations centre"

Questions

(a) Since THI is a virtual utility with no employees, please confirm that the sentence quoted in the preamble refers to the employees of the Town of Tillsonburg taking home vehicles owned by THI.
(b) Are the employees in question a) above allowed personal use of the vehicles? If the answer is yes, is there a services agreement between the Town of Tillsonburg and THI that allows the employees of the Town to operate THI-owned vehicles and take them home? If the answer is yes, please file the services agreement if it is not already in evidence. If the answer is no, please explain why not.

Responses

(a) Please see response to EP-1(a) above. The sentence quoted in the preamble correctly refers to THI employees.

(b) Not applicable.

EP-3

Reference

APPENDIX C Purchase and Sale Agreement dated April 27, 2026, between the Applicant and the Seller, Appendix 3, Employees

Question

(a) Please confirm that all of the individuals listed by name in Appendix 3 Employees are employees of the Town of Tillsonburg and not of THI.

Response

(a) All the individuals listed by name in Appendix 3 Employees are currently employees of the Town of Tillsonburg but, as per the response to EP-1(a) above, the individuals will be transferred to and become employees of THI on or before the closing of the Phase 1 transaction.

EP-4

Reference

Exhibit G, Customer Services Agreement

Preamble: "AND WHEREAS Seller will retain its customer service employees (the "Customer Service Employees") following completion of the transactions contemplated by the Purchase Agreement and will make such employees available to provide Customer Service Support to the Corporation in accordance with the terms and conditions hereof;"

Question

(a) Are the Customer Service Employees included in the list Appendix 3 Employees referred to in question EP-3?

Response

(a) No. The Customer Service Employees referenced in the Customer Services Agreement are employees of The Town of Tillsonburg that will continue to provide customer service support to THI for a period following the closing of Phase 1 pursuant to the terms of the Customer Services Agreement.

EP-5

Reference

SPECIAL RESOLUTION OF THE SHAREHOLDERS MERGER WITH TILLSONBURG HYDRO INC., Date: August 15, 2025, pages 2 and 3

Preamble: "(4) negotiation and execution of the necessary post-closing agreements required upon closing including, without limitation, the terms and conditions regarding the transfer of utility-related employees and related equipment from Town to the merged LDC or EPC's competitive businesses and finalized contacts and any approvals required from the County of Oxford authorizing ERTH to undertake water billing for the Town shall be a condition of closing."

Questions

(a) Who are the "utility-related employees" in the text quoted in the preamble?
(b) Are they the individuals listed in *Appendix 3 Employees* referred to in question EP-3 or are some other individuals also included?

Responses

(a) The "utility-related employees" in the text quoted in the preamble are the individuals listed in *Appendix 3 Employees* referred to in question EP-3.

(b) See response to EP-3(a) above.

EP-6

Reference

SPECIAL RESOLUTION OF THE SHAREHOLDERS MERGER WITH TILLSONBURG HYDRO INC., Date: August 15, 2025, pages 5

"Preamble: Job Guarantees – The Merged LDC would provide job guarantees to all identified Town employees engaged in the THI operations. These employees will either be transferred to the Merged LDC or one of EPC's competitive affiliates on or before the closing of the Proposed Transaction (the "Transferred Employees"). Seniority and service credits for these Transferred Employees will be maintained. For those Town employees unable or unwilling to be transferred, ERTH and EPC agree to maintain their respective services following the closing the Proposed Transaction via a service agreement with the Town, if required."

Questions

(a) Will THI cease to be a virtual utility when the transfer of Town employees is completed?
(b) Please confirm that the Merged LDC will be a real utility with its own employees and not with virtual employees as THI was prior to the merger.

Responses

(a) Yes.

(b) Confirmed.

EP-7

Reference

EB-2023-0053 THI Settlement Proposal, pages 21 and 22

Preamble: The following is a quote from the Settlement Proposal referenced above.
"3.4 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?
Full Settlement
The Parties accept the evidence of THI that all impacts of any changes to accounting standards, policies, estimates, and adjustments have been properly identified in the Application and the interrogatories and have been recorded and treated appropriately in the ratemaking process. The Parties note that THI continues to operate as a "virtual" utility; THI has no employees, it relies entirely on The Corporation of the Town of Tillsonburg ("the Town") for its human and other resources including executive and senior management, some of which is provided to the Town by ERTH Power Inc. through a services agreement. The intervening Parties expressed concern as to how under this structure THI is able to meet the various obligations, including certain MIFRS accounting standards, imposed on THI as a regulated distributor.
In order to address these concerns, the Parties have agreed that THI will file an independent study in its next Cost of Service that reviews its virtual utility operating structure to confirm that it is

meeting its various obligations as a distributor of electricity regulated by the OEB. Without limiting the generality of the foregoing, it is anticipated that the study will address the following identified concerns:

- *a) that the virtual utility model does not result in the rejection of alternatives that are materially more cost efficient;*
- *b) that the derivation of the costs provided to the THI virtual utility are appropriate and can be determined to be appropriate through clear and transparent information as to the Town's costs, including how any markups are derived and applied;*
- *c) that, where appropriate, market price data for services provided to the virtual utility by its affiliate is obtained to confirm that the prices paid by the regulated entity to the Town are reasonable;*
- *d) that the accounting standards and regulatory requirements as applicable to the virtual utility and its affiliate are being properly adhered to and applied to affiliate transactions;*
- *e) that the "Shared Services" costs can be clearly distinguished in description and quantum from the Town's other costs;*
- *f) that it can be clearly demonstrated that the Cost Allocation Model used to allocate costs from the Town to THI entity is being properly applied;*
- *g) that an independent verification of the data underpinning the Cost Allocation Model can and has been undertaken;*
- *h) that the fiduciary duties of the officers of the virtual utility and appropriate corporate governance over the virtual utility are being properly maintained within the virtual utility structure Specifically, that the study will examine the question of conflict, real or potential, which may arise in the circumstances where senior municipal officers of the Town (CEO, COO, CFO, etc.) share their time and act in the place of senior corporate officers of the virtual utility.*

The Parties recognize that it remains open to THI to change its corporate structure prior to its next Cost of Service application. If THI elects to do so and files its next cost of service application as a non-virtual utility, then the Parties agree that to the extent THI elects to change its corporate structure the scope of the independent study may be adjusted to reflect that change."

Questions

(a) Please confirm that the corporate structure of THI will be changed and the Merged LDC will not be a virtual utility.
(b) Does the Merged LDC still plan to file the independent study? If the answer is yes, when will the independent study be filed? If the answer is no, why not?

Responses

(a) Confirmed.

(b) If the proposed THI transaction is approved, the Applicant does not plan to file the independent study given that THI will no longer operate as virtual entity on or before the closing of the proposed THI transaction.

Section 2(b) – Pollution Probe

THI-PP-1

Reference

"… the first phase of a two-phase transaction whereby ERTH is purchasing all of the issued and outstanding shares in Tillsonburg Hydro Inc. from The Corporation of the Town of Tillsonburg."

Questions

(a) Was a merger instead of an outright purchase of shares considered and/or evaluated? If no, why not. If yes, please provide a copy of the materials used for consideration or in making the decision.
(b) Was there any public consultation conducted to engage the community and ratepayers during this process? If not, why not. If yes, please provide copies of the materials used and copies of the feedback collected.

Responses

(a) The Applicant respectfully submits that this is not relevant to the THI proceeding. As set out in the Decision and Order in EB-2005-0234/0254/0257[8] and reiterated in the MAADs Handbook[9], the Board's role in this proceeding is not to determine whether another transaction, whether real or potential, can have a more positive effect than the one that has been negotiated to completion by the parties.

(b) The Applicant respectfully submits that this is not relevant to the THI proceeding. Pursuant to the MAADs Handbook[10], the OEB will not consider issues relating to the extent of the due diligence or public consultation and applicants are directed not file details of public consultation prior to the filing of the application.

THI-PP-2

Reference

None.

Question

(a) Please provide responses (if any) to all community and ratepayer input/comments, including (but not limited to) those filed with the OEB.

[8] EB-2005-0234/0254/0257, Decision and Order, page 6.
[9] MAADs Handbook, Section 4.3, page 14-15.
[10] MAADs Handbook, Section 4.3, pages 14-15.

Response

(a) The Applicant respectfully submits that this is not relevant to the THI proceeding on the grounds described in response to THI-PP-1(a) above.

THI-PP-3

Reference

None.

Question

(a) Please provide a copy of any business case, presentations or similar documents provided to the THI and/or EPC Board of Directors and/or their direct or indirect shareholders with respect to the approval transaction (either preliminary or final approval).

Response

(a) The documents described in THI-PP-3 contain details regarding (i) negotiations leading to the proposed THI transaction, (ii) alternative transactions that may have been considered, (iii) the due diligence process, (iv) the results of public consultations conducted before filing the Application, (v) the contents of draft purchase agreements and confidential negotiating documents, and (vi) discussions regarding negotiating strategies. Accordingly, pursuant to the MAADs Handbook[11], the Applicant respectfully submits that this is not relevant to the THI proceeding.

THI-PP-4

Reference

None.

Questions

a) Please describe how local planning and delivery (including municipal energy and emissions planning and support aligned with the Distribution System Plan) will be impacted if the acquisition is approved. If incremental benefits will result to enhance energy and emissions planning, alignment and activities in the municipality, please provide details.
b) Please describe what utility activities (including eDSM promotion and delivery) the acquisition will maintain or enhance to support ratepayer programs and regulated energy and emissions reporting and reductions requirements under Ontario requirements for municipalities and all

[11] MAADs Handbook, Section 4.3, pages 14-15.

broader public sector buildings served.

Responses

(a) The Applicant respectfully submits that that the degree to which the proposed transaction impacts local planning and delivery of municipal energy and emissions planning and support is not relevant to the WPI proceeding as the requested information is not relevant to the OEB's statutory objectives as set out in section 1 of the *Ontario Energy Board Act, 1998*., as assessed pursuant to the MAADs Handbook. [12]

(b) The Applicant respectfully submits that this is not relevant to the THI proceeding. Pursuant to the MAADs Handbook [13], the OEB has identified that evidence relating to conservation is not relevant to the MAADs approval proceeding

THI-PP-5

Reference

None.

Questions

(a) Please confirm that the THI rebasing deadline will move from 2027 to 2035 if the OEB approves the Applicant's request for a deferred rebasing period of nine (9) years for THI following the Phase 1 transaction. If not correct, please clarify.
(b) If the OEB were to approve the requested 9 year rebasing deferral for THI, does that impact THI from merging with EPC until the rebasing term is over (e.g. 2035)? If not, please explain how costs and benefits related to THI would be tracked and filed at the end of the deferred rebasing term.
(c) How does the proposed deferred rebasing period noted in part a align (or not) with a rebasing application of the consolidated utility following the EPC (2029) rebasing application?
(d) Please explain the treatment of and timing of THI deferred rates and synergies over the deferred rates period starting prior to the Phase 2 (2029) rebasing application for EPC compared to following Phase 2. For examples, what ratepayer benefits and synergies are forecasted to occur before/after the EPC 2029 rebasing application and how will those be accounted for separately from those expected from the EPC deferred rates period (9 years per EB-2018-0082).
(e) Is it correct that only Phase 1 impacts the proposed THI deferred rates period and Phase 2 does not. If not correct, please explain.

Responses

[12] MAADs Handbook, Sections 3 and 4, pages 6-15.
[13] MAADs Handbook, Sections 4.1 and 4.2, pages 9 and 15.

(a) THI's current rebasing deadline as per its last rebasing in 2024 is 2029. If the OEB approves the request for a deferred rebasing period of nine (9) years for THI following the Phase 1 transaction, the Applicant confirms that the next rebasing for THI will be in 2035 instead of 2029.

(b) The OEB's approval of the requested nine-year rebasing deferral for THI does not restrict THI from merging with EPC until the rebasing term is over (e.g. 2035). Costs and benefits related to THI would be tracked in a similar manner as done in previous transactions (e.g. West Coast Huron Energy Inc., EB-2018-0082) and THI will continue as a separate rate zone after Phase 2 and until the end of the nine-year rebasing deferral period.

(c) Any rebasing application of the consolidated utility following Phase 2 will recognize the nine-year rebasing deferral via a separate rate zone as described in response to THI-PP-5(b) above.

(d) THI will continue to file its Incentive Rate Setting Mechanism ("IRM") rate applications as a separate rate zone until 2035 when the harmonized rate rebasing application will be submitted by the consolidated utility.

The ratepayer benefits and synergies that are forecasted post Phase 1 and post Phase 2 are set out in the amended Table 5 included in response to Staff-41.

(e) As explained above, both Phase 1 and Phase 2 impact the proposed THI deferred rates period.

THI-PP-6

Reference

The Applicant intends to maintain a local physical presence very similar to what THI's customers experience today. Following closing of the Phase 1 transaction, the Applicant has committed to maintaining THI's existing customer service centre in the Town of Tillsonburg and assuming THI's existing lease commitment for its operation centre located at 43 John Pound Road, Tillsonburg. [Page 25]

Questions

(a) Please explain any expected decrease in functions at the THI office in Tillsonburg following Phase 1 and/or Phase 2 transactions. Please explain where those functions will move to and the expected decrease in THI office space requirements. If annual savings estimates are available, please also provide them.
(b) Please provide the most recent three years of (OM&A and Capital) costs related to the THI office in Tillsonburg.

(c) Does THI or ERTH have an estimate of costs and benefits (OM&A and Capital) if the THI office is downsized or closed. If yes, please provide them.

Responses

(a) There will be no expected decrease in functions at the THI office in Tillsonburg following the Phase 1 transaction, which is the subject of this application. Any changes to the functions at the THI office in Tillsonburg following the merger of THI, EPC, and WPI will be dealt with in the Phase 2 application.

(b) The most recent three years of (OM&A and Capital) costs related to the THI office in Tillsonburg are set out below:

Year	Operating Expenses	Rent Paid	Lease	Total
2023	$0	$150,000	$0	$150,000
2024	$23,948	$150,000	$66,918	$240,866
2025	$73,713	$0	$133,836	$207,549
2026	$75,625	$0	$133,836	$209,461

(c) Please see the response to THI-PP-6(b) above.

THI-PP-7

Reference

These modest cost savings are possible related to the elimination of certain management roles and a reduction in various redundant expenses (e.g. board remuneration, industry associations, etc.), which will be largely offset by cost of the shared corporate services provided by ERTH. [Page 20] and Table 5: Forecasted Revenue Requirements – Status Quo vs. Post Transaction [Page 23]

Questions

(a) Please provide a list of the management roles and the various redundant expenses expected to be reduced.
(b) Please provide a table including details for each position and expense forecasted to be reduced. In the table, please provide the annual THI fully costs for the past 3 years, the expected cost and reduction following Phase 1, and the expected cost and reduction following Phase 2.
(c) Please provide the details of the annual synergies in Table 5 - Forecasted Revenue Requirements – Status Quo vs. Post Transaction.
(d) Please explain the impact of the OEB approving Phase 1, but rejecting Phase 2. If there is an impact to proposed synergies, please provide an update to Table 5 based on only approval of Phase 1.

Responses

(a) ERTH Corporation currently provides management services to THI pursuant to services agreement. The management services provided by ERTH and EPC are meant to replace the management services previously provided by THI's General Manager, a position that no longer exists. The management services contract described above will be terminated at closing of the proposed transaction. The various redundant expenses include a reduction in the number of paid board members from seven (7) to three (3).

(b) The table below provides the past 3 years of expense items forecasted to be reduced. The Human Resources savings indicated below reflect the elimination of the ERTH management services contract described in paragraph (a) above.

	2023	2024	2025
Facility Rent and Operational Costs	$ 150	$ 241	$ 207
Human Resources savings via Vacant Roles	$ 120	$ 120	$ 120
Redundant Contract Services	$ 123	$ 128	$ 147
Director Fees Savings	$ 88	$ 104	$ 95
Redundant Association Memberships	$ 57	$ 57	$ 56
Total	**$ 2,561**	**$ 2,674**	**$ 2,650**

in thousands

The expected costs and reductions for Phase 1 and Phase 2 are detailed in response to paragraph (c) below.

(c) The details of the annual synergies in Table 5 - Forecasted Revenue Requirements – Status Quo vs. Post Transaction are set out below:

THI Operating Synergies	1/2 year 2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Human Resources savings via Vacant Roles	-	120,000	123,600	127,308	131,127	135,061	139,113	143,286	147,585	152,012
Board expense	-	-	-	59,007	59,007	59,007	59,007	59,007	59,007	59,007
Membership Fees	-	-	-	45,000	46,350	47,741	49,173	50,648	52,167	53,732
COS Regulatory Costs	-	-	-	37,000	37,000	37,000	37,000	37,000	37,000	37,000
Rent and building	-	-	-	189,258	189,258	189,258	189,258	189,258	189,258	189,258
Redundant contracts			-	171,860	171,860	171,860	171,860	171,860	171,860	171,860
ERTH Corp Allocations	(90,610)	(186,657)	(192,257)	(198,025)	(203,965)	(210,084)	(216,387)	(222,878)	(229,565)	(236,452)
Vehicle branding & Lic	-	(11,000)	(11,000)	-	-	-	-	-	-	-
Total	**(90,610)**	**(77,657)**	**(79,657)**	**431,409**	**430,637**	**429,843**	**429,024**	**428,181**	**427,313**	**426,418**

(d) There is no impact on proposed synergies identified in Phase 1 if Phase 2 is not approved.

THI-PP-8

Reference

For purposes of this Application, it is critical to note that THI's existing cost structures have recently been approved by the OEB as necessary to maintain ongoing financial and operational viability. It can reasonably be assumed that maintaining THI's existing expenditure levels is sustainable from an operational and financial perspective over the rebasing period proposed in this Application. [Page 24]

Questions

(a) Please provide a table of the OEB approved rate term budgets by major category (2024-2028) and add columns to extrapolate those out to the end of the 9 year rates deferral term requested.
(b) Please provide a copy of the table requested in part a, removing the proposed synergies, by year.
(c) Please provide the total OM&A and Capital funding difference between the responses for part a and b, above.

Responses

(a) A table of the OEB approved rate term budgets by major category (2024-2028) is set out below:

	Forecast Spending $k per Year					
OEB Category	**2024**	**2025**	**2026**	**2027**	**2028**	**Avg**
System Access	$ 149	$ 209	$ 198	$ 455	$ 469	$ 296
System Renewal	$ 1,161	$ 1,525	$ 1,106	$ 1,121	$ 1,154	$ 1,214
System Service	$ 749	$ 442	$ 539	$ 615	$ 633	$ 596
General Plant	$ 75	$ 75	$ 75	$ 55	$ 57	$ 67
Total	$ 2,134	$ 2,251	$ 1,919	$ 2,245	$ 2,313	$ 2,172

Please note that the table above only includes capital expenses as THI does not provide OM&A expenses by year beyond the 2024 test year.

Table of the OEB approved rate term budgets by major category post 2028 will be included in the Phase 2 application.

(b) The table set out in response to THI-PP-8 does not include synergies.

(c) Not applicable, as described above.

THI-PP-9

Reference

Accordingly, the proposed transaction is forecasted to positively impact the customers of THI with respect to adequacy, reliability, and quality of electricity service due to the efficiencies expected to be generated from the transaction. [Page 26]

Questions

(a) Please provide the estimated improvements expected with respect to THI adequacy, reliability, and quality of electricity service due to the efficiencies expected to be generated from the transaction. Please also explain how these will be tracked and reported to the OEB in comparison to historical results in Table 8.
(b) THI Reliability Indicators (Excluding MED's & Loss of Supply Events) are significantly lower than EPC and WCI. Please explain how merging with EPC and WCI would help lower THI's results.
(c) Would a single set of results for the merged utility be reported following Phase 2? If yes, please explain how that will enable comparison to the historical THI results.

Responses

(a) The proposed transaction is forecasted to positively impact the customers of THI with respect to adequacy, reliability, and quality of electricity service for the reasons described the THI application, namely (i) access to EPC's expertise in SCADA (Supervisory Control & Data Acquisition) systems, improving response times and troubleshooting efforts, (ii) improved storm response resources including access to a larger pool of power line maintainers, inventory and equipment, (iii) an electrical system that will ultimately be displayed, managed, and operated from the EPC Control Room, and (iv) THI employees who are on call and live in or within close proximity to the Town of Tillsonburg will be permitted to take THI-owned work vehicles home allowing such employees to respond promptly to outages and other emergency situations without the need to return to an operations centre.

(b) Please see response to PP-THI-9(a) above.

(c) The Applicant respectfully submits that this is not relevant to the current WPI proceeding requesting approval of Phase 1. The manner in which the merged utility reports its results will be addressed in the Phase 2 application.

THI-PP-10

Reference

There will be a large benefit to THI customers through all future phases of the transaction in the form of technology enhancements in the THI service territory that would otherwise not be economical or practical to implement. In the proposed transaction incorporates the benefits to be realized through voluntary consolidation; it will deliver cost synergies and economy of scale benefits and will promote the Board's objectives. [Page 26-27, including list of examples]

Questions

a) Please provide annual OM&A and Capital savings expected from the cost synergies and economy of scale benefits noted above.
b) Please indicate how these cost synergies and economy of scale benefits will be tracked for THI over the deferred rates period and reported to the OEB at the time of rebasing.
c) Please explain any incremental distribution energy resource or non-wire solutions opportunities that the enhanced technology and capacity would enable.
d) What specific incremental results and benefits are expected for THI as a result of access to ERTH's enhanced environmental, social and governance (ESG) functions.

Responses

a) The minimal annual OM&A and Capital savings expected from the cost synergies and economy of scale benefits associated with Phase 1 are set out in Table 5 included with the THI Application. A detailed description of the annual OM&A and Capital savings expected from the cost synergies and economy of scale benefits associated with Phase 2 will be set out in in the Phase 2 Application

b) Please see response to Staff-25.

c) The enhanced technology and capacity described in the THI Application are expected to provide a number of incremental DER or non-wire solutions opportunities including, for example, optimizing THI's localized DER dispatch and improving real-time grid visibility for NWAs.

d) Access to ERTH's enhanced ESG function is predicted to enable THI to improve organizational performance by embedding sustainability, stakeholder considerations, and strong governance into strategic planning, operations, and decision-making. The resulting benefits may include reduced operating costs and environmental impacts through improved energy efficiency, emissions reduction, and climate resilience; enhanced employee engagement, safety, diversity, and retention; increased customer satisfaction and participation in energy efficiency and electrification programs; stronger community and municipal relationships; improved regulatory compliance and enterprise risk management; more transparent and accountable governance; and better access to financing and strategic partnerships. Ultimately, a mature ESG function is intended to strengthen THI's long-term resilience, supports the energy

transition, enhances public trust, and creates measurable value for customers, municipal shareholders, employees, regulators, and the communities it serves.

THI-PP-11

Reference

THI will have access to ERTH's customer service practices which recently resulted in an increase in its OEB regulated Customer Satisfaction Survey results from 76% in 2023 to 94% in 2025. [Page 27]

Question

(b) Please update Table 9 including 2025 results for all THI and EPC Customer Focus Statistics.

Response

(a) Please see an update to Table 9 below setting out the 2025 results for all THI and EPC Customer Focus Statistics:

Year	New Residential/Small Commercial Services connected On-Time (Target:90%)			Scheduled Appointments met On-Time (Target: 90%)		Telephone Calls Answered On-Time (Target :65%)		First Contact Resolution		Billing Accuracy (Target:98%)		Customer Satisfaction Survey Results	
	EPC		THI	EPC	THI	EPC	THI	EPC	THI	EPC	THI	EPC	THI
2025	95.37%		100.00%	99.55%	99.79%	88.03%	99.11%	100.00%	98.90%	98.30%	99.85%	94.00%	Satisfied

THI-PP-12

Reference

The integration costs will be financed through the anticipated productivity savings expected from the transaction during the period after the Phase 2 transaction. As always, there will be timing differences between expense outlays and their recovery. [Page 30]

Questions

(a) Please identify the integration costs from Phase 1, but before Phase 2.
(b) How will Phase 1 productivity costs be funded?
(c) Please explain how the relevance of Phase 2 anticipated productivity savings for OEB consideration in this Phase 1 application?
(d) How would this be treated if Phase 2 is not approved.

Responses

(a) Please see responses to Staff-16.

(b) Please see responses to Staff-16.

a) The anticipated Phase 2 productivity savings are relevant in so far as without approval of the Phase 1 transaction, none of the Phase 1 or Phase 2 synergies will be possible.

b) If Phase 2 is not approved, the Phase 1 transaction and integration costs will continue to be funded in accordance with response to WPI-PP-28(b).

THI-PP-13

Reference

None.

Questions

(a) Please explain if there are any issues should the OEB approve a THI deferred rates period of up to 9 years approved on an interim basis and subject to the Phase 2 application review within 5 years. If the Phase 2 application is not filed within 5 years, then deferred rates period becomes 5 years for THI. If this impacts the business case or benefits flowing to ratepayers, please identify what would specifically change.

Responses

(a) Please see responses to Staff-5 and Staff-49.

THI-PP-14

Reference

Rate harmonization may be addressed as part of the Phase 2 Transaction. [Page 33]

Questions

a) Please explain what factors would lead to rate harmonization not being included as part of the Phase 2 application.
b) Could the Phase 2 rate deferral period be a term different than the residual of the 9 year rate deferral period from the THI Phase 1 proceeding? If yes, please explain how this would align with the Phase 1 decision requested.

Responses

(c) The Applicant respectfully submits that this question is too speculative to answer. The Phase 2 application has not yet been filed, and the circumstances that may exist at the time of that application cannot be determined with certainty at this time. The decision regarding whether rate harmonization will form part of the Phase 2 application will be based on a number of factors that will be assessed closer to the time of filing, including the regulatory environment, operational considerations, customer impacts, integration

progress, and any applicable OEB guidance or requirements in effect at that time.

The Applicant reiterates that any subsequent deferred rebasing period will be less than 10 years after the OEB approval of this Application.

(d) Please see response to Staff-16.

Section 2(c) – OEB Staff

Staff-29

Reference

Share Purchase Agreement
Ref 1: THI MAADs Application, Appendix C, Schedule A, p. 4 (pdf p.199)
Ref 2: THI MAADs Application, Appendix D, p.32 (pdf p.79)

Preamble:
OEB staff notes that the Local Presence section under Closing Covenants in Appendix C does not align with the corresponding section in Appendix D. Reference 2 includes closing provision allowing employees who are on call to take Buyer-owned vehicles home, while Reference 1 does not have.

Questions

a) Please explain the difference described in Preamble.
b) Please confirm whether Appendix C is the most up-to-date Purchase and Sale Agreement for reference.

Responses

a) Appendix C, Schedule A, p.4 (pdf p.199) is a non-binding letter of intent that formed the basis for future negotiations between the parties. The definitive legal agreement set out in Appendix D, p.32 (pdf p.79) contains the applicable binding provision.

b) Confirmed.

Staff-30

Reference

Future Investment Plan
Ref 1: Tillsonburg Hydro and ERTH Power: Building a Stronger, Hometown Utility Together - Town of Tillsonburg
Ref 2: EB-2023-0053 Tillsonburg Hydro 2024 DSP Plan

Preamble:
OEB staff notes that, on THI's website, THI states that the main reason for collaborating with ERTH is that, as a stand-alone utility, THI faces challenges to require an investment of at least $29 million.

Questions

(a) Please confirm whether the estimated $29 million investment is entirely incremental to the DSP Plan approved in its last rebasing application. If not, please identify the portion that is incremental to the approved 2024 DSP Plan.
(b) Please provide the timeline of the projected construction for the $29 million portfolio, specifically whether this will be executed during the proposed 9-year deferred rebasing period.
(c) Please provide an estimate of the bill impacts on THI, WPI, and EPC customers associated with the estimated $29 million investment requirement.

Responses

(a) Confirmed.

(b) There is currently no timeline available for the project as it is to facilitate future capacity. THI is currently working with the Independent Electricity System Operator ("IESO") on the Integrated Regional Resource Plan ("IRRP") for its area. The IRRP process will provide a draft report at the end of 2026 and will be finalized in 2027. Once the report is complete, plans will begin with the provincial transmitter and all impacted distributors with respect to any potential project.

(c) No estimate of bill impacts is available at this time since the potential investment is still under review as part of the IESO IRRP and any bill impacts will depend on the economic model used, any capital contribution received, etc.

Staff-31

Reference

Regulatory Approval
Ref: THI MAADs Application, Appendix C – Share Purchase Agreement, Section 13(a)(ii), p. 45 [PDF page 92 of 368]

Preamble:
A portion of reference 1 states the following: "Each of Buyer and Seller will use commercially reasonable efforts to co-operate and assist the other, so that the OEB Approval can be obtained on or prior to May 31, 2026."

Questions

(a) Please describe any impact due to the difference in the date of OEB approval per the Share Purchase Agreement to the proposed THI transaction.
(b) With respect to the THI MAADs Application, if approved by the OEB, please advise on the expected close of the transaction.

Responses

(a) The date set out in Section 13(a)(ii) of the Share Purchase Agreement (May 31, 2026) was included simply as a target date to ensure the parties used the appropriate efforts to obtain OEB approval of the proposed THI transaction. Accordingly, there are no impacts on the proposed THI transaction due to a change in the actual OEB approval date.

(b) Pursuant to the definition of "Closing Date" in Appendix 1 of the Share Purchase Agreement, if approved by the OEB, the expected transaction closing date will be within thirty (30) days after the date on which the OEB issues the OEB Approval.

Staff-32

Reference

THI Prior Commitments / Directives
Ref 1: THI MAADs Application, p. 7
Ref 2: EB-2023-0053, Decision and Rate Order, November 12, 2024
Ref 3: EB-2024-0056 THI 2025 IRM Application
Ref 4: EB-2025-0007 THI 2026 IRM Application

Preamble:
The Application states that THI last rebased for rates effective November 1, 2024 (EB- 2023-0053). Further, as part of Phase 1 of the transaction, THI will remain a distinct legal entity operating under a separate license with common corporate and financial oversight from ERTH Corporation.
OEB staff notes that in EB-2023-0053, the parties to that proceeding reached a complete settlement on all issues on the approved issues list. The OEB approved the settlement agreement.

Questions

(a) Please outline any commitments between parties resulting from the 2024 cost of service settlement agreement in EB-2023-0053 and/or any directives from the OEB in its decision.
(b) Please confirm that THI, owned by ERTH Corporation, will implement and/or address the matters outlined pursuant to the 2024 cost of service settlement agreement and/or OEB decision in EB-2023-0053.
    i. For each commitment or directive, please specifically indicate in which future application they will be addressed.
(c) Please confirm if there are any OEB directives stemming from the decisions in references 3 and/or 4. If yes, please describe and identify if they have been or when they will be addressed.

Responses

(a) Please see response to EP-7.

(b) Please see response to EP-7.

i. Please see response to EP-7.

(c) Please see response to EP-7.

Staff-33

Reference

Incremental Transaction and Transition Costs
Ref: THI MAADs Application, p. 30

Preamble:
The Application states that,

- *Incremental one-time transaction and transition costs are expected to be approximately $250k and will not be funded by ratepayers.*
  - *Incremental transaction costs include but are not limited to due diligence on the part of all parties, the costs associated with negotiating the terms of the purchase, costs associated with all regulatory, legal and statutory reviews to receive necessary regulatory approvals and internal resources.*
  - *Incremental transition costs that are expected as a result of the Phase 2 transaction include information technology, legal, and professional advisory services.*
- *Integration costs will be financed through the anticipated productivity savings expected from the transaction during the period after the Phase 2 transaction. These costs are primarily related to transition planning and execution, IT costs, communication costs, workforce training.*

Questions

(a) Please clarify if the $250k includes transaction and transition costs relating to the Phase 1 transaction, the Phase 2 transaction, or both.
   i. If any of the costs relate to both Phase 1 and Phase 2, please clarify how much relate to each transaction / provide an estimated apportionment.
   ii. If any of the costs in Phase 1 are related to Phase 2, please comment on whether it is necessary to incur those costs during Phase 1, given that the Phase 2 application will be filed as a later date.

(b) Please clarify who will pay the incremental one-time transaction and transition costs and where the money will come from.

(c) Do the $250k transaction and transition costs include the "integration costs" noted in the preamble (bullet point 3), or are these separate costs?
   i. If these are separate, please provide forecasts for all integration costs associated with the proposed transaction broken down by category and by year in which the costs are expected. OEB staff has provided a sample table below:
   ii. To the extent that there are any transition (integration) costs prior to Phase 2, how does ERTH expect these costs to be financed in the interim given that "costs will be financed through the anticipated productivity savings expected from the transaction during the period after the Phase 2 Transaction."

(d) If synergies and cost efficiencies do not materialize as expected, how does ERTH plan to address any financial viability issues that may occur?

Questions

(a) Based on the definitions in the MAADs Handbook,[14] the $250k includes incremental transaction costs relating to the Phase 1 transaction only. The Applicant interpreted transition costs incorrectly in the THI Application and it submits that there will be no transition costs associated with Phase 1. The incremental transaction and transition costs related to the Phase 2 transaction (i.e. information technology, legal, and professional advisory services related to consolidating the three utilities) will be detailed in the Phase 2 application.

   i. Not applicable.

   ii. Not applicable.

(b) The Applicant will pay for the incremental one-time transaction and transition costs. Neither THI nor EPC will pay for any incremental one-time transaction and transition costs. The $250k of Phase 1 transaction costs will be funded via ERTH Corporation's existing credit facility with its lender or retained cash.

(c) The $250k transaction do not include the "integration costs" noted in the preamble (bullet point 3).

   i. The "integration costs" are detailed in the Applicant's responses Staff 41(b) and THI-PP-7(c).

   ii. To the extent that the above costs or any other transition (integration) costs arise prior to Phase 2, the Applicant submits that these costs will be financed in the interim via ERTH Corporation's existing credit facility with its lender

[14] MAADs Handbook, Section 4.3, page 13.

or retained cash.

(d) The Applicant submits that the failure to recognize synergies and cost efficiencies following Phase 1 transaction will have no impact on the financial viability of the stand-alone utilities (who will bear no transaction or transition costs associated with the Phase 1 transaction and will continue to operate as per usual.)

Staff-34

Reference

Post Consolidation Monitoring and Reporting
Ref 1: THI MAADs Application, p. 33
Ref 2: MAADs Handbook, pp. 33-35

Preamble:
The Applicant states a mid-term report for THI will be filed given that it is deferring rebasing for more than five years. The mid-term report will contain the required components as set out in the Post-Consolidation Monitoring and Reporting section of the MAADs Handbook. The Applicant also confirms that in its first rebasing application updates to the mid-term report will be provided for any period not included in that report.

Questions

(a) Please confirm the year that the mid-term report will be filed.
(b) Please confirm if the mid-term report proposed as part of this Phase 1 Application will detail the required components solely as it relates to THI. If not, please explain.
(c) If the OEB approves the Phase 1 and Phase 2 transactions, how does ERTH intend to report on the required components as set out in the Post-Consolidation Monitoring and Reporting section of the MAADs Handbook following Phase 2 and at the time of the rebasing of the consolidated entity? Please clarify the proposal with respect to post consolidation reporting.

Responses

(a) The Applicant plans to mid-term report will be filed in 2031.

(b) Confirmed.

(c) Following Phase 2, the Applicant intends to report on the required components set out in the Post-Consolidation Monitoring and Reporting section of the MAADs Handbook together as a consolidated entity. Currently, the Applicant plans to submit a mid-term report that includes the following information, collected on a reasonable efforts basis:

- Progress to date on (i) the various activities where efficiencies were expected, (ii) the savings achieved associated with those efficiencies, and (iii) the recovery of transaction and transition costs will be reported using the table set out below:

Activity	Expected Efficiencie	Actual Efficiencies	Realized Savings
Activity 1			
Activity 2			
Activity 3			
		Total Savings:	
		(Transaction Costs)	
		(Transition Costs)	
		NET RESULTS	

- A qualitative discussion on enhanced reliability and service quality as a consolidated distributor and on a rate zone basis.
- A discussion on potential obstacles going forward in reaching the consolidated entity's targets as set out in the consolidation application, if any.
- An updated revenue requirement analysis as provided in the consolidation application based on information known at the time of the filing of the mid-term report, and a variance analysis to explain material differences to what was filed in the consolidation application will be reported using the table set out below:

Revenue Requirement Analysis (Application)	Revenue Requirement Analysis (Updated)	Variance	Analysis
Item 1			
Item 2			
Item 3			

Staff-35

Reference

Reliability Reporting
Ref 1: THI MAADs Application, pp. 19, 33

Preamble:
The Application states that THI and ERTH Power Corporation will continue to report separately.
ERTH Corporation will file Phase 2 of the transaction for approval by OEB to allow for the amalgamation of ERTH Power Corporation, WPI, and THI.
*The Application states that **during the proposed deferred rebasing period** (emphasis added by OEB staff), THI will continue to report system level reliability as part of its annual RRR filings to the OEB.*

Questions

(a) Please clarify whether, as part of this Application, the Applicant is proposing that THI continue to report system level reliability separately to the OEB for the entirety of the proposed deferred rebasing period (i.e., 9 years), or will a separate proposal be brought forth in Phase 2 regarding reliability reporting for the consolidated entity (or the legacy utilities within the consolidated entity)?
    i. Please provide further supporting rationale for the proposal.
(b) Please provide further information on the anticipated post consolidation reliability reporting at the time of the Phase 2 application which will seek to combine the service areas to be served by a single merged utility. For example, will each utility continue to report system level reliability separately until the combined entity rebases as one?

Responses

(a) A separate proposal will be brought forth in the Phase 2 application regarding reliability reporting for the consolidated entity (or the legacy utilities within the consolidated entity).

    i. The Applicant will continue to have the ability to separately track reliability for THI and the other legacy utilities (based on feeder and service community) following Phase 2, and it will be prepared to report the same in RRR filings or otherwise.

(b) Following Phase 2 and until the combined entity rebases as one., it is not expected that the merged entity will report separate reliability reporting, however New EPC will have the ability to track and report segmented (e.g. separated by rate zones) reliability statistic in its midterm and final report as part of its harmonizing rate application.

Staff-36

Reference

THI Employees
Ref 1: MAADs Application, Appendix C – Share Purchase Agreement, Section 9(e)(ii)
Ref 2: THI MAADs Application, p. 19

Preamble:
Reference 1 states that "Buyer shall cause the Corporation to employ the Employees on substantially the same terms and conditions for a minimum duration of three (3) years following the Closing Date."
The Application seeks a nine-year deferred rebasing period for THI. It is the Applicant's intent at this point that a Phase 2 application would be filed in 2029, following the conclusion of ERTH

Power Corporation's cost of service application.

Questions

(a) Please confirm whether all THI employees will continue employment with THI on substantially the same terms and conditions until the Phase 2 application is filed.
(b) Will the Phase 2 application outline the plans for employees of the amalgamating LDCs?
(c) Please elaborate on how the Applicant expects the Phase 1 transaction to impact the roles and functions of THI and ERTH Power Corporation staff, especially those responsible for service quality and distribution system reliability.

Responses

(a) Confirmed. Please see response to EP-1.

(b) Yes. Although the Applicant cannot be specific about individual employees' positions being made redundant at this point, the Applicant intends to outline the plans for employees of the amalgamating LDCs at a high level in the Phase 2 application.

(c) The Applicant does not anticipate that the Phase 1 transaction will result in any material changes to the roles and responsibilities of existing THI or EPC staff, particularly those positions directly responsible for the safe operation, maintenance, service quality and reliability of the distribution systems.

Following completion of Phase 1, THI and EPC will continue to operate as separate licensed electricity distributors with separate distribution systems, operating centres, control room functions, field operations, engineering, maintenance, asset management, customer service and regulatory obligations.

The Applicant's intent during Phase 1 is to maintain "business as usual" operations while establishing common corporate ownership and governance. Accordingly:

- Existing operational and field staff at both THI and EPC will continue to perform their current roles and responsibilities, while sharing operational best practices.
- Staff responsible for distribution system operations, maintenance, outage response, vegetation management, engineering, system planning, asset management and reliability will remain in place and continue to support their respective service territories.
- Existing operational procedures, emergency response practices, reliability

programs and maintenance activities will continue unchanged, with a view to exchanging best practices between the two utilities.

- Customers will continue to receive service from their existing utility under its existing distribution licence, with no changes to day-to-day utility operations resulting from Phase 1.

Staff-37

Reference

Service / Operations Centre
Ref: THI MAADs Application, p. 28

Preamble:

The Application states that the current operation centre will be maintained in the THI and ERTH Power Corporation territories throughout the duration of the Phase 1 transaction. During Phase 2 and beyond, the main headquarters are expected to be ERTH Power Corporation's new office and operations centre approved by the OEB in EB-2024-0021. Functions such as engineering, procurement, human resources, finance, legal, regulatory, information technology, and customer service will be administered and delivered from the Ingersoll location, with each location having operations staffing similar to current resourcing levels.

Questions

(a) Please explain how successful coordination between the operations centre of THI and ERTH Power Corporation will be ensured, both post Phase 1 and post Phase 2 (if approved by the OEB) given that the service area boundaries of each utility are not contiguous.

(b) Please clarify if and how any customer service functions that are currently administered at THI's current location will change post Phase 1 vs. post Phase 2.

i) Will there be any effect on the availability of services provided to THI customers in the physical THI service area?

Responses

(a) Please see response to Staff-14.

(b) The customer service functions that are currently administered at THI's current location will not change post Phase 1. The details regarding which customer service functions may be moved to ERTH Power's Ingersoll location post Phase 2 have not been finalized and they will be addressed in the Phase 2 application.

i) There will be no change in the availability of services provided to THI customers in the physical THI service area.

Staff-38

Reference

Affiliate Matters
Ref 1: THI MAADs Application, p. 22
Ref 2: THI MAADs Application, pp. 10-11 Ref 3:
THI MAADs Application, pp. 22, 29

Preamble:

Reference 1 states that if this Application is approved, all utilities owned by ERTH Corporation, including ERTH Power Corporation and THI, receive shared common corporate and financial oversight from ERTH Corporation pursuant to Affiliate Relationships Code compliant services agreements.
Reference 2 identifies the business of the Applicant's affiliates to the proposed transaction.
Reference 3 states that ERTH and its affiliates are in fact currently providing management oversight and other operational services to THI have been assisting THI for over 15 years by providing a variety of services and support (including billing, hosting, engineering, utility construction, metering, etc.).

Questions

(a) Please fully describe the extent to which the THI has been utilizing the services of ERTH and its affiliates identified in the Application for the last 15 years.
(b) Please confirm whether the services provided by ERTH and its affiliates will be updated as part of the Phase I application. If so, please also provide an updated version of the 2 tables above.
(c) Given the excerpt noted in the preamble from reference 2, please specifically explain how compliance with 2.1.2 of the *Affiliate Relationships Code*, which requires that a utility ensure that at least one-third of its Board of Directors is independent from any affiliate, will be achieved.

Responses

(a) The Applicant's competitive affiliates have provided a variety of services to THI over the 15 years including the management services described in response to THI-PP-7(a), hosting services, bill print and stuff, line construction services, metering services, customer portal and Green Button software, and hub and spoke services.

(b) The Applicant respectfully submits that the two tables provided in Staff-38 are not relevant as neither ERTH nor its affiliates are affiliated with or a parent company of THI.

(c) Following Phase 1, THI will utilize the shared corporate services that ERTH

Corporation and ERTH (Holdings) Inc. currently provide EPC, which are reflected in the table below:

Shared Services

Name of Company		Service Offered
From	To	
ERTH (Holdings) Inc.	Tillsonburg Hydro Inc.	Information management services, information technology services.

Corporate Cost Allocation

Name of Company		Service Offered
From	To	
ERTH Corporation	Tillsonburg Hydro Inc.	Strategic management and policy support, legal services, building support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, public affairs.

(d) Please see response to Staff-9(c).

Staff-39

Reference

Cost Savings
Ref 1: THI MAADs Application, p. 22
Ref 2: THI MAADs Application, Table 5

Preamble:
The Application states that although the Phase 1 transaction will result in moderate transaction and transition costs, as well as management fees payable to ERTH Corporation, these additional THI costs will be offset by the modest cost savings for WPI described.

Question

(a) Please confirm if the THI synergies included in Table 5 are net of transaction and transition fees, as well as management fees payable to ERTH Corporation (p.22). If not, please explain and confirm if net synergies are still anticipated once all these noted costs are considered.

Response

(a) Confirmed.

Staff-40

Reference

Service Quality Statistics
Ref 1: THI MAADs Application, p. 25
Ref 2: WPI MAADs Application, Appendix E, Scorecards of WPI and EPC [PDF p. 249]

Preamble:
Reference 1 states "Throughout both phases of this transaction, it is the intention of the Applicant to maintain the service levels of WPI through the merging of technologies, system control, adoption of best work practices, etc."
Based on the 2024 OEB Scorecards provided in the Application at reference 2, OEB staff has summarized the Customer Focus metrics for THI and ERTH Power Corporation. OEB staff has highlighted certain results where THI has achieved results slightly higher than ERTH Power Corporation.

		2020		2021		2022		2023		2024	
		Tillsonburg	ERTH Power	Tillsonburg	ERTH Power	Tillsonburg	ERTH Power	Tillsonburg	ERTH Power	Tillsonburg	ERTH Power
Service Quality	New Residential/Small Business Services Connected on Time	100.00%	98.59%	99.51%	95.84%	95.34%	97.05%	100.00%	95.76%	99.62%	95.11%
	Scheduled Appointments Met on Time	99.36%	100.00%	98.21%	99.06%	99.30%	100.00%	98.60%	99.18%	99.79%	99.53%
Customer Satisfaction	First Contact Resolution	97.20%	99.58%	97.70%	99.26%	94.70%	99.43%	96.90%	99.66%	98.90%	99.91%
	Billing Accuracy	99.80%	99.75%	97.60%	99.85%	99.70%	99.62%	99.85%	99.69%	99.85%	97.01%

Questions

(a) Please provide 2025 results for THI and ERTH Power Corporation.
(b) Please more fully describe how, at a minimum, current service levels of THI will be maintained. As part of the response, please provide examples as to where / how service levels will be maintained and / or improved "through the merging of technologies, system control, adoption of best work practices." As part of the response, please also specifically discuss how the metrics highlighted by OEB staff will be, at minimum, maintained for THI.

Responses

(a) The 2025 results for THI and ERTH Power Corporation are set out below:

Year	New Residential/Small Commercial Services connected On-Time (Target:90%)		Scheduled Appointments met On-Time (Target: 90%)		Telephon Calls Answered On-Time (Target :65%)		First Contact Resolution		Billing Accuracy (Target:98%)		Customer Satisfaction Survey Results	
	EPC	THI	EPC	THI	EPC	THI	EPC	THI	EPC	THI	EPC	THI
2025	95.37%	100.00%	99.55%	99.79%	88.03%	99.11%	100.00%	98.90%	98.30%	99.85%	89.00%	Satisfied

(b) The Applicant's intent during Phase 1 is to maintain "business as usual" operations while establishing common corporate ownership and governance. Accordingly, existing customer services, operational and field staff at THI will continue to perform their current roles and responsibilities, which is expected to maintain the two metrics highlighted by OEB staff. Moreover, the Applicant is optimistic that the following examples of "the merging of technologies, system control, adoption of best work practices" improve THI's current services levels:

- The sharing of engineering and operational expertise between THI and EPC, which will lead to higher quality operations and maintenance plans that will benefit customers of both THI and EPC;
- Access to EPC's expertise in SCADA (Supervisory Control & Data Acquisition) systems, improving response times and troubleshooting efforts;
- Extension of the ERTH social media platforms (Twitter, Facebook, LinkedIn) to include THI to aid in the promotion of distributor activities, engagement of customers, and communication of outage information;
- THI will have access to expanded ERTH corporate services; and
- Emergency storm response resources will improve as THI will have access to ERTH's larger pool of power line maintainers, inventory and equipment (which will be shared in accordance with the *Affiliate Relationships Code*).

Staff-41

Reference

Comparative Forecasted Revenue Requirement Analysis
Ref 1: THI MAADs Application, pp. 22-24, Tables 5 and 6
Ref 2: THI MAADs Application, p. 21

Preamble:

Table 5 of the Application provides the forecasted revenue requirements for each of THI and ERTH Power Corporation for each year between 2026 and 2035 under post- consolidation and status quo scenarios. Table 6 outlines the assumptions regarding inflation, growth and productivity included

in the analysis.
In Reference 2, the Applicant requests that following Phase 1, THI and ERTH Power be permitted to continue to operate as independent utilities until the Phase 2 application is filed.

Questions

(a) Please explain why the difference in revenue requirement in the "post transaction" scenario is greater than the synergies achieved beginning in 2029.
(b) Please explain why the synergies for THI from Year 0 to Year 2 are not negative in Table 5.
(c) Please explain why the "no transaction" scenario in Table 5 does not include a rebasing application post 2029 for THI, and post 2028 for ERTH Power Corporation.
(d) Please confirm OEB staff's understanding that the synergies listed in Table 5 are solely OM&A-related.
    i. If yes, please describe any capital savings that are anticipated following the Phase 1 transaction. If none are expected as part of Phase 1, please explain why not.
    ii. Are there capital-related synergies anticipated as part of the Phase 2 transaction? If yes, please describe. If not, please explain why not.
(e) Please confirm if, for each year under the Phase 1 transaction in both the "no transaction" and "transaction" scenarios, the utility specific stretch factor for each of THI and ERTH Power Corporation were applied. OEB staff observes that in Table 6 there is a combined stretch factor listed for these years (in addition to utility specific stretch factors for THI and ERTH Power Corporation), but it is unclear what stretch factor is utilized in the analysis.
    i. If a combined stretch factor was used for any of the years under Phase 1, please explain why given the proposal in reference 2 (i.e., that THI and ERTH Power be permitted to continue to operate as independent utilities until Phase 2). OEB staff notes that as per the PEG Report to the OEB[6], THI is in Group 2, and ERTH Power Corporation is in Group 3.
(f) Please re-file Tables 5 and/or 6 based on the responses to the above questions, if required. Please also include any updated commentary, if required, regarding updated figures / results in the status quo and post-consolidation scenarios.

Responses

(a) The reason why the revenue requirement in the "post-transaction" scenario is greater that than the synergies achieved beginning in 2029 because THI rebases in that year (2029) in the "no transaction" scenario and it does not rebase in the "post-transaction" scenario.

(b) The negative synergies shown in Years 0 through 2 reflect integration costs associated with implementing Phase 1 which will be offset by operational efficiencies and sustainable synergies realized in subsequent years.

(c) The "no transaction" scenario in Table 5 does not include a rebasing application post 2029 for WPI, and post 2028 for ERTH Power Corporation due to an oversight. An updated Table 5 is set out in response to Staff-41(f) below.

(d) Confirmed.

i. No capital savings are anticipated following the Phase 1 transaction. THI recently filed an approved DSP as part of its 2024 COS application and, as a condition of the proposed transaction, the Applicant has agreed to continue to invest in the THI system pursuant to the approved DSP. The approved DSP runs through 2028 and, as such, there are no synergies as part of Phase 1 related to capital expenditures.

ii. Yes, there are capital-related synergies anticipated as part of the Phase 2 transaction. The extent of these synergies has not been identified and will be detailed in the Phase 2 application.

(e) The utility specific stretch factor for each of THI and EPC was utilized for each year under the Phase 1 transaction in both the "no transaction" and "post-transaction" scenarios. However, there was a cell reference error for EPC in Table 5 contained in the original THI application.

i. A combined stretch factor was not utilized.

(f) An updated Table 5 is set out below:

Revenue Requirement - No Transaction										
(dollars in thousands)	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	IRM	COS	IRM	IRM	IRM	IRM	COS	IRM
THI	$ 5,963	$ 6,256	$ 6,339	$ 7,607	$ 8,043	$ 8,150	$ 8,258	$ 8,368	$ 9,623	$ 10,042
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	COS	IRM	IRM	IRM	IRM	COS	IRM	IRM
EPC	$ 17,766	$ 18,388	$ 23,132	$ 24,105	$ 24,460	$ 24,784	$ 25,113	$ 28,879	$ 30,138	$ 30,537
ICM	$ 2,317	$ 2,317								
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	IRM	COS	IRM	IRM	IRM	IRM	IRM	IRM
WPI				$ 18,583	$ 19,650	$ 19,910	$ 20,174	$ 20,442	$ 20,714	$ 20,991
No Transaction Total	**$ 26,046**	**$ 26,961**	**$ 29,471**	**$ 50,295**	**$ 52,153**	**$ 52,843**	**$ 53,545**	**$ 57,689**	**$ 60,476**	**$ 61,570**

Revenue Requirement - Phase 1 and Phase 2 Transactions	Yr Phase 1 MAADs			Yr 4 Phase 2 MAADs						Harmonized Rebasing
(dollars in thousands)	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM
THI	$ 5,963	$ 6,256	$ 6,339	$ 6,389	$ 6,474	$ 6,560	$ 6,647	$ 6,736	$ 6,826	$ 6,917
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	COS	IRM	IRM	IRM	IRM	IRM	IRM	IRM
EPC	$ 17,766	$ 18,388	$ 23,132	$ 24,105	$ 24,460	$ 24,784	$ 25,113	$ 28,879	$ 30,138	$ 30,537
ICM	$ 2,317	$ 2,317								
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM
WPI				$ 15,608	$ 15,815	$ 16,025	$ 16,238	$ 16,455	$ 16,675	$ 16,898
Synergies THI	$ 91	$ 78	$ 80	-$ 431	-$ 431	-$ 429	-$ 429	-$ 428	-$ 427	-$ 426
Synergies WPI				-$ 48	-$ 55	-$ 338	-$ 345	-$ 354	-$ 362	-$ 371
Transaction Total	**$ 26,137**	**$ 27,039**	**$ 29,551**	**$ 45,623**	**$ 46,262**	**$ 46,601**	**$ 47,224**	**$ 51,288**	**$ 52,850**	**$ 53,555**

Staff-42

Reference

OM&A Savings and Analysis
Ref: THI MAADs Application, Table 7, p. 24

Preamble: OEB staff has reproduced Table 7 below.

OM&A Costs (dollars in thousands)	Phase 1				Phase 2	Post Consolidation Period				
	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028 EPC Test Year	Yr 3 2029 MAADs Application	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8- 2034	Yr 9 - 2035
EPC	$ 11,103	$ 11,252	$ 11,388	$ 11,728	$ 12,052	$ 12,413	$ 12,786	$ 13,169	$ 13,564	$ 13,971
THI	$ 3,557	$ 3,628	$ 3,700	$ 3,774	$ 3,738	$ 3,850	$ 3,965	$ 4,084	$ 4,207	$ 4,333
WPI				$ 9,026	$ 9,251	$ 9,483	$ 9,720	$ 9,963	$ 10,212	$ 10,467
EPC + THI + WPI	$ 14,659	$ 14,880	$ 15,088	$ 24,528	$ 25,041	$ 25,746	$ 26,471	$ 27,216	$ 27,983	$ 28,771
Synergies THI	$ 91	$ 78	$ 80	-$ 431	-$ 431	-$ 429	-$ 429	-$ 428	-$ 427	-$ 426
Synergies WPI				-$ 48	-$ 55	-$ 338	-$ 345	-$ 354	-$ 362	-$ 371
Forecasted OM&A	$ 14,750	$ 14,958	$ 15,168	$ 24,049	$ 24,555	$ 24,979	$ 25,697	$ 26,434	$ 27,194	$ 27,974
OM&A / Customer										
EPC	$ 444.85	$ 450.82	$ 456.27	$ 469.90	$ 420.89	$ 428.16	$ 440.47	$ 453.11	$ 466.13	$ 479.51
THI	$ 415.85	$ 424.16	$ 432.65	$ 441.30						

Questions

(a) Please provide 2025 actual OM&A costs per customer for each of ERTH Power Corporation and THI.
(b) Please provide an explanation as to how the Applicant forecasted the OM&A for each utility on a standalone basis for year 1 and the growth for each subsequent year.
(c) Please explain all material assumptions made with respect to the forecasted OM&A cost savings.
(d) Please provide a breakdown of the OM&A cost savings indicating which are attributable to the following categories: administrative, governance, information technology, regulatory, finance, legal or other (please specify).

Responses

(a) The 2025 actual OM&A costs per customer for each of ERTH Power Corporation and THI are set out below:

OM&A Costs (dollars in thousands)	2025
EPC	$ 9,548
THI	$ 3,211
Forecasted OM&A	$ 12,759
OM&A / Customer	
EPC	$ 377.56
THI	$ 371.90

(b) The Applicant forecasted OM&A expenses for each utility on a stand-alone basis using each utility's approved Year 1 budget. For subsequent years, THI's OM&A was escalated by an annual growth factor of 2.5%, while EPC's approved five-year budget forecast was applied through 2030, after which an annual growth factor of 3.0% was applied

(c) The Applicant projected cost savings based on the applicable 2026 budgeted costs associated with the identified synergy initiatives. Those costs were escalated by an annual inflation factor of 3.0% in each subsequent year of the analysis.

(d) A detailed description of the identified synergies is provided in the Applicant's response to THI-PP-7. The identified synergies are limited in number and value and, accordingly, the Applicant has not broken out the identified synergies into the itemized detail requested in Staff-42(d) and the requested information is not available.

Staff-43

Reference

SAIDI / SAIFI
Ref 1: THI MAADs Application, Table 8, p. 26
Ref 2: THI MAADs Application, Appendix E – 2024 Scorecards of WPI and EPC

Questions

(a) Please provide 2025 SAIDI / SAIFI results.
(b) Given that THI's 2024 SAIFI and SAIDI results exceeded EPC's, how will EPC ensure that THI customers' reliability is maintained and not adversely affected by the proposed transaction?

Responses

(a) The 2025 SAIDI / SAIFI results for THI and EPC are set out below:

THI	2025
SAIDI	1.53
SAIFI	1.44
ERTH	2025
SAIDI	0.61
SAIFI	0.18

(b) While, at first glance, ERTH Power's historical system reliability performance may appear to be less favourable than THI's, this comparison does not account for the utilities' respective distributor-specific performance targets. EPC's distributor-specific targets are significantly more stringent, with SAIDI and SAIFI targets of 0.91 and 0.39, respectively, compared to WPI's targets of 0.87 and 0.64. Over the five-year period reported in their respective 2024 OEB Scorecards, EPC recorded average SAIDI and SAIFI results of 1.34 and 0.55, while WPI recorded 0.74 and 0.62. EPC's performance in terms of duration of outages is superior to THI even though THI is a contiguous, transmission connected utility.

The Applicant further submits that the proposed transactions are not expected to adversely affect system reliability. During Phase 1, THI will continue to operate as it does today, maintaining its existing operations centre, outage response processes, and field resources. ERTH Corporation has consistently demonstrated a strong commitment to system reliability and outage response and intends to apply the same operational focus and performance culture across the combined organization.

Staff-44

Reference

Timeline
Ref 1: THI MAADs Application, pp. 7-8, 19-20, 23, 31
Preamble:
Page 19 of reference 1 states that the intent is that a Phase 2 MAADs application would be filed in 2029, while page 20 states the Phase 2 application will be submitted to the OEB in 2028.

Question

(a) Please explain the discrepancy in the preamble and confirm the year that the Phase 2 application will be submitted to the OEB.

Response

(a) The Applicant's intention is to submit the Phase 2 application in 2028 with the view that it would be effective January 1, 2029.

Staff-45

Reference

Accounting treatment

Questions

(a) Please describe any material differences in accounting policies or deferral and variance account treatment between EPC and THI, including, but not limited to: capitalization policy, depreciation policy, and interest or carrying charge methodology of the DVAs.
   i. Please discuss any impacts on future consolidated reporting.
(b) Please confirm the regulatory accounting basis used for pension and OPEB expenses for EPC and THI, i.e. accrual vs. cash basis.
   i. If the accounting basis differs between the two, please explain how the Applicant intends to harmonize these practices post-merger.

Responses

(a) There are no material differences in accounting policies or deferral and variance account treatment between EPC and THI.

   i. Not Applicable.

(b) Following the closing of the Phase 1 transaction, both THI and EPC will leverage the cash basis for OPEB expenses.

Staff-46

Reference

ESM
Ref 1: THI_ERTH _MAADs Application, p. 19 & 31
Ref 2: Handbook to Electricity Distributor and Transmitter Consolidations, July 11, 2024, section 5.1 & 5.6
Ref 3: THI_ERTH _MAADs Application, Appendix G

Preamble:
*Per reference 1, the Applicant states that upon completion of the EPC CoS Application, EPC, WPI and THI will bring a second application to the Board to approve the second phase ("**Phase 2**") of the transaction to allow for the amalgamation of EPC, THI and WPI under section 86(1)(c)*

*of the OEB Act. The ultimate amalgamated entity will operate under the name ERTH Power Corporation ("**New EPC**").*
The Applicant requests the OEB's approval of a 9-year rate rebasing deferral period for THI assuming that the Phase 1 transaction is approved and closes in 2026, the end of the requested 9-year rate deferral period will occur in the 2035 rate year. It proposes to implement earnings sharing mechanism ("ESM") for THI (the "THI ESM") for years six to nine of the rebasing deferral periods.
OEB staff notes that the New EPC is the consolidated entity which will be established in Phase 2. It will be formed upon completion of the approved amalgamation of EPC, WPI, and THI.
Per reference 2, the OEB permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction. Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years.
Per reference 3, OEB staff also notes the ESM Deferral Account is proposed to be established under THI instead of the New EPC.

Questions

(a) OEB staff understands that, following completion of Phase 2, EPC, WPI, and THI will amalgamate to form the New EPC.
   i. Please confirm whether the proposed nine-year deferral rebasing period is intended to apply to the amalgamated entity (New EPC).
   ii. If confirmed, please explain the rationale for applying a nine-year deferral rebasing period to THI in Phase 1, while THI is expected to cease to exist as a standalone distributor and become part of New EPC upon completion of Phase 2.
   iii. If this nine-year deferral rebasing period is not intended to apply to New EPC, please explain how the proposed deferral rebasing period would operate following the amalgamation of THI into New EPC.

(b) Please confirm OEB staff's observations that the proposed ESM Deferral Account would be established for THI rather than for New EPC.
   i. Please confirm whether the ESM Deferral Account is proposed to be established for THI as a standalone entity.
   ii. If yes, please explain the rational for establishing the ESM Deferral Account for THI, given that THI is expected to amalgamate with EPC and WPI to form New EPC during Phase 2.
   iii. Please discuss whether establishment of the ESM Deferral Account under New EPC would be more appropriate following completion of the amalgamation. If not, please explain why not.
   iv. Please comment on the appropriateness of calculating the ESM based on the weighted-average achieved ROE of the amalgamated utilities (i.e., EPC, WPI, and THI), and identify the proposed ESM effective period, including the commencement and end dates.
   v. Please explain how any ESM balances would be tracked, reported, and transferred (if applicable) following the amalgamation into New EPC.

(c) Per reference 3, with respect to the disposition of ESM balances, please discuss:
   i. When the Applicant proposed to calculate and report any ESM amounts during the deferral rebasing period.
   ii. When and through what proceeding(s) the Applicant proposes to seek disposition of any non-zero ESM balances.

Responses

(a) The Applicant respectfully submits that the amalgamated entity ("New EPC") has not yet been established. In this application, the Applicant is seeking approval for a nine-year deferred rebasing period applicable to THI. Upon completion of the Phase 2 amalgamation of THI into New EPC, the Applicant intends to seek the OEB's approval for the balance of the deferred rebasing period then remaining to apply to the amalgamated entity.

i. Confirmed.

ii. The negotiated transaction involved the ratepayers of THI receiving a nine-year rate deferral regardless of whether THI remained as a stand-alone distributor. If the transferring the balance of the deferred rebasing period to New EPC is approved, the Applicant will establish a separate rate zone for THI ratepayers in the same manner that it did in its acquisition and subsequent consolidation of West Coast Huron Energy Inc.

iii. Not applicable.

(b) The Applicant submits that the proposed ESM Deferral should be established for New EPC following Phase 2. During Phase 1, THI will be operated separately, and New EPC will not have been established yet so there will be no merged entity to calculate the deferral account against.

i. See above Staff-25(b) above.

ii. Not applicable.

iii. See above Staff-25(b) above.

iv. The appropriateness of calculating the ESM based on the weighted-average achieved ROE of the amalgamated utilities and the proposed ESM effective periods will be addressed in the Phase 2 application.

v. The manner in which ESM balances will be tracked, reported, and balanced will be addressed in the Phase 2 application.

(c) Per reference 3, with respect to the disposition of ESM balances, please discuss:

i. The timing of calculating and reporting any ESM amounts during the deferral rebasing period will be addressed in the Phase 2 application.

ii. The manner in which the Applicant proposes to seek disposition of any non-zero ESM balances will be addressed in the Phase 2 application.

Staff-47

Reference

DVA
Ref 1: THI_ERTH MAADs Application, p. 31 & 33
Ref 2: Handbook to Electricity Distributor and Transmitter Consolidations, July 11, 2024, section 5.9, Tracking of Accounts

Preamble:
Per reference 1, the Applicant requests the OEB's approval of a 9-year rate rebasing deferral period for THI during which it will operate under the OEB's Price Cap IR framework. Assuming that the Phase 1 transaction is approved and closes in 2026, the end of the requested 9-year rate deferral period will occur in the 2035 rate year.
With respect to timing of Group 2 disposition, EPC will be filing its rebasing applications as scheduled and THI has recently had its rebasing application approved. There will be no impacts to intergenerational inequity because of this Phase 1 application as EPC and THI will be maintaining the same disposition schedule for these accounts.
The Applicant requests the OEB's approval to continue to track costs in the deferral and variance accounts currently approved by the OEB for THI.
Per reference 2, utilities may gain efficiencies by tracking accounts on a consolidated basis, rather than a rate zone basis. Given the nature of the Group 1 accounts and the reliance on data from various systems (e.g., billing system), it is likely practical and efficient for utilities to consolidate the Group 1 accounts for new activities post-closing of the transaction. Therefore, for Group 1 accounts, the OEB encourages utilities to consolidate the accounts as soon as it is practical.

Questions

(a) Per reference 2, the OEB encourages utilities to consolidate the Group 1 accounts as soon as it is practical, please explain the Applicant's proposed approach to the treatment of Group 1 accounts following Phase 1, including:
   i. Whether and when the Applicant expects to consolidate the Group 1 accounts of THI and EPC.
   ii. If the Group 1 accounts will not be consolidated, the reasons why and how the Applicant proposes to address the OEB's expectation that Group 1 accounts be consolidated as soon as practical.

(b) For the request of approving to continue tracking costs in DVAs currently approved by the OEB, please clarify whether this request applies to:
   i. Group 1 DVAs only; or
   ii. Both Group 1 and Group 2 DVAs.
   Please provide supporting rationale.

(c) If the Applicant begins receiving a consolidated IESO invoice, please explain:
   i. Whether separate Group 1 accounts balances for THI and EPC can

continue to be maintained;

ii. How any separate balances would be tracked and supported; and

iii. Whether the Applicant would consider consolidating the Group 1 accounts at that time rather than maintaining separate rate-zone-level accounts. If not, why not?

(d) Please confirm that EPC and THI will continue to keep track and record the transactions separately for all Group 2 accounts during the post-amalgamation period, including Account 1592 sub-account CCA changes?

i. If not, please explain the proposed alternative approach.

(e) Please clarify when/which year THI will seek disposition of Group 2 accounts.

i. If disposition is expected to occur more than five years after THI's most recent rebasing application, please discuss the impact of intergenerational inequity and how the Applicant proposes to address them.

Responses

(a) Since EPC and THI will continue to operate as stand-alone entities, any consolidation of Group 1 accounts will not occur until post Phase 2 as a minimum. The Applicant anticipates consolidation of Group 1 balances after Phase 2 once the utilities are operating with one distribution license and one IESO invoice.

(b) For the request of approving to continue tracking costs in DVAs currently approved by the OEB, this request applies to Group 1 and Group 2 DVAs because THI will continue to operate separately with a separate IESO invoice which requires the Group 1 and Group 2 DVAs to be tracked independently of one another.

(c) Once the Applicant begins receiving a consolidated IESO invoice following Phase 2, Group 1 balances would be consolidated and, as such, separate balances would not be tracked or supported. The Applicant would consider consolidating the Group 1 accounts following the completion of Phase 2.

(d) Confirmed.

(e) The Applicant intends to dispose of its Group 2 Accounts prior to filing its harmonized Cost of Service application in 2035 in order to mitigate potential intergenerational inequity. The Applicant is also willing to consider any options or recommendations proposed by OEB Staff that would facilitate the timely disposition of these accounts.

Staff-48

Reference

Ref 1: THI_ERTH _MAADs Application, p. 22

Preamble:

In the Reference above, the Applicant intends to eliminate various management roles and related costs.

Questions

(a) Please confirm whether there are any costs associated with eliminating these various management roles.
(b) If yes, please provide the amount of these costs and confirm whether they are included in the one-time transaction or transition costs, and offset by the productivity savings.
(c) If these costs are not included in the transaction or transition costs, please indicate who will be responsible for them.

Responses

(a) The Applicant confirms that there are no costs associated with eliminating these various management roles. Please see response to THI-PP-7.

(b) Not applicable.

(c) Not applicable.

SECTION 3: EWAI/Westario & ERTH/Tillsonburg Combined Interrogatories

Section 3(a) – Pollution Probe

THI/WPI-PP-31

Reference

None.

Question

(a) Please provide a table which includes the current rebasing timeline for THI, Westario, and EPC. Please provide a column to show what the new proposed rebasing dates (or single date if combined) will be as impacted by the Phase 2 timeline following the EPC 2028 rebasing application.

Response

(a) A table which includes the current rebasing timeline for THI, Westario, and EPC is set out below:

Phase 1 MAADs		ERTH COS	Phase 2 MAADs						Harmonized Rebasing
Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035

THI/WPI-PP-32

Reference

None.

Questions

(a) Please provide a table of the net ratepayer benefits (and related time periods) expected from each of the THI, WPI, and EPC deferred rates periods. Please confirm that these amounts are each separate and cumulative. If not, please explain and provide the cumulative totals.
(b) What procedures and controls will be in place to avoid double counting benefits and synergies between the EPC rebasing, THI acquisition and merger, and WPI acquisition and merger (including Phase 2)?

Responses

(a) A table of the net ratepayer benefits (and related time periods) expected from each

of the THI, WPI, and EPC deferred rates periods is set out below:

	Yr Phase 1 MAADs			Yr 4 Phase 2 MAADs						Harmonized Rebasing
(dollars in thousands)	Yr 0 - 2026	Yr 1 - 2027	Yr 2 - 2028	Yr 3 2029	Yr 4 - 2030	Yr 5 - 2031	Yr 6 - 2032	Yr 7 - 2033	Yr 8 - 2034	Yr 9 - 2035
Synergies THI	$ 91	$ 78	$ 80	-$ 431	-$ 431	-$ 429	-$ 429	-$ 428	-$ 427	-$ 426
Synergies WPI	-$ 20	-$ 50	-$ 54	-$ 48	-$ 55	-$ 338	-$ 345	-$ 354	-$ 362	-$ 371
Transaction Total	**$ 71**	**$ 28**	**$ 26**	**-$ 479**	**-$ 486**	**-$ 767**	**-$ 774**	**-$ 782**	**-$ 789**	**-$ 797**
Cumulative		**$ 99**	**$ 54**	**-$ 453**	**-$ 965**	**-$ 1,253**	**-$ 1,541**	**-$ 1,556**	**-$ 1,571**	**-$ 1,586**

The above table presents the total projected synergies for the three entities, comparing the stand-alone (no transaction) scenario with the proposed transaction scenario. The synergies are shown on a cumulative basis over the 9-year deferred rebasing periods applicable to both the Phase 1 and Phase 2 transactions.

(b) To ensure that benefits and synergies are appropriately attributed and that double counting does not occur between the EPC rebasing application, the acquisitions of WPI and THI, and the eventual consolidation of the three utilities, the Applicant is currently planning to establish a centralized synergy tracking framework. This framework would maintain a record of each identified synergy, including the originating utility, transaction phase, implementation timing, financial impact, and methodology used to quantify the benefit. Clear ownership would be assigned for each synergy initiative, supported by consistent baseline methodologies, financial coding, and reporting practices to distinguish between efficiencies already reflected in approved rates, benefits arising from individual acquisitions, and incremental benefits resulting from future consolidation.

Prior to each regulatory filing, the Applicant anticipates performing reconciliation reviews to confirm that previously identified synergies are not included again in subsequent applications and that any newly claimed benefits are incremental. Transaction-specific synergy schedules, documented approval processes, and periodic post-transaction reviews would be used to validate assumptions, monitor realized benefits, and ensure that efficiencies are appropriately allocated and reported throughout the transition and consolidation process.

THI/WPI-PP-33

Reference

*Reference: Upon completion of the EPC CoS Application, EPC, WPI and THI will bring a second application to the Board to approve the second phase ("**Phase 2**") of the transaction to allow for the amalgamation of EPC, THI, and Westario under section 86(1)(c) of the OEB Act. [THI Page 19 and WPI Page 21]*

Questions

(a) Please explain how ERTH is planning to reconcile costs and net benefits for the proposed THI and WPI 9 year deferred rates terms if a Phase 2 application is brought forward part way through the 9 year deferred rates period for THI/WPI?
(b) Does implementation of Phase 2 end the 9 year THI or WPI deferred rates period prematurely? If no, why not. If yes, please explain the impacts, including net benefits expected from Phase 1.
(c) Does ERTH anticipate requesting a new deferred rates period for the merged utilities (EPC, WPI and THI) as part of the Phase 2 application? If yes, please provide how that would correlate to the deferred rates term approved as part of a Phase 1 decision for THI and WPI.

Responses

(a) Please see responses to Staff-5, Staff-25, Staff-35 and Staff-49.

(b) Please see responses to Staff-5, Staff-25, Staff-35 and Staff-49.

(c) Please see responses to Staff-5, Staff-25, Staff-35 and Staff-49.

THI/WPI-PP-34

Reference

Reference: Figure 3: Phase 2 - Corporate Ownership Structure [THI Page 20 and WPI Page 20]

Questions

(a) Please provide a short description of the business and services related to each box in Figure 3.
(b) Please provide details on which elements of THI and WPI are subsumed by merged entity structure noted in Figure 3.
(c) Please note which boxes in Figure 3 are unregulated or affiliates and explain if they will be providing services to THI and/or WPI.

Responses

(a) Please see Section 2.1 of the THI application (pages 10-11).

(b) The details regarding the merged entities will be filed with the Phase 2 application.

(c) Please see Section 2.1 of the THI application (pages 10-11) and the responses to Staff-9 and Staff-38.

THI/WPI-PP-35

Reference

None.

Questions

(a) When will THI and WPI file its updated Business Plan and Distribution System Plan (DSP)?
(b) When will the fully merged utility have an integrated Business Plan and Distribution System Plan (DSP) based on the merged utility and when would it be filed with the OEB?
(c) In the interim, how will the Business Plan and/or DSP be coordinated between THI/WPI and EPC?

Responses

(a) Both THI and WPI will continue to operate on a stand-alone basis, and the existing Business Plans and DSP for each utility will continue to apply. The Phase 2 application will detail the treatment of those plans post 2029.

(b) An integrated Business Plan and DSP based on the merged utility will be addressed in the Phase 2 application.

(c) Each utility will continue to operate on a stand-alone basis pursuant to their respective Business Plans and DSPs.

THI/WPI-PP-36

Reference

Reference: If this Application is approved, the combined ownership of WPI/THI and EPC by ERTH will allow the LDCs to access capital at lower interest rates versus stand- alone utilities that are not commonly owned. [WPI Page 32 and THI Page 27]

Question

(a) Please provide details on the lower capital costs expected for WPI and THI and what the annual savings are forecasted to be per year for each utility.

Response

(a) The Applicant respectfully submits that this question is too speculative to answer. The Applicant reiterates that the proposed transaction will allow the LDCs to access capital at lower rates, but it cannot forecast the actual annual savings will be until the proposed transaction is finalized and will be based on capital market conditions at that time.

Section 3(b) – Board Staff

Staff-49

Reference

Proposed Rate Framework
Ref 1: WPI MAADs Application, pp. 7, 8, 20-21 Ref 2: THI MAADs Application, pp. 6-7,19

Preamble:
References 1 and 2 outline the "Proposed Rate Framework". The respective applications note that the Proposed Rate Framework is an integral, and non-severable of the proposed two-phase transaction and the Applicant's overall Application.
OEB staff's understanding of the Proposed Rate Framework is summarized as follows:

- *ERTH Power Corporation, WPI and THI will remain distinct legal entities operating under separate licenses following Phase 1.*
- *ERTH Power Corporation will file a cost of service application for rates effective May 1, 2028, following the completion of a nine-year deferred rebasing period approved by the OEB in EB-2018-0082.*
- *WPI will not rebase following Phase 1. EWAI seeks to defer rebasing of WPI for a nine-year period following the Phase 1 transaction.*
- *THI will not rebase following Phase 1. ERTH Corporation seeks to defer rebasing of THI for a nine-year period following the Phase 1 transaction.*

Questions

(a) Please confirm or correct OEB staff's understanding of the elements of the "Proposed Rate Framework".
(b) Prior to bringing forth the Proposed Rate Framework as stipulated, did the Applicant(s) consider any alternative frameworks? If yes, please describe. If not, please explain why not, including rationale for why the Proposed Rate Framework is the preferred approach.
(c) If the answer to (b) is yes, please explain why the Applicant(s) chose not to pursue an alternative approach.

Responses

(a) Confirmed.

(b) As noted in the WPI Application and the THI Application, there are a number of reasons why the Applicants did not consider any alternative rate frameworks including (i) to ensure that the synergies that arose from the prior consolidation of EPC and West Coast Huron Energy Inc. are passed along to ratepayers; (ii) ending the ICM rate rider and incorporating the new facility into base rates; and (iii) implement the Board's direction in EB-2024-0021 to provide evidence on affiliate

usage of new facility in order to determine appropriate recovery of costs previously excluded from the ICM period.

(c) Not applicable.

Staff-50

Reference

Rate Harmonization
Ref 1: WPI MAADs Application, p. 34
Ref 2: THI MAADs Application, p.33
Ref 3: MAADs Handbook, July 11, 2024, p. 30

Preamble:

Reference 1 and 2 both states that the Applicants will not be harmonizing rates at the time of rebasing as part of the Phase 1 transaction. Rate harmonization may be addressed as part of the Phase 2 transaction.

Reference 3 states:

> *A statement indicating whether the consolidated utility intends to undertake rate harmonization at the time of rebasing or, if not, an explanation for not doing so, should be included in the consolidation application. Where the utility does intend to harmonize rates, a brief description of the plan should also be provided. This information can be informative to the OEB as to the intentions of the consolidated entity.*

Question

(a) Please confirm that, pursuant to the current MAADs Handbook, the Phase 2 application will indicate whether the consolidated utility intends to undertake rate harmonization at the time of rebasing or, if not, an explanation for not doing so. Where the utility does intend to harmonize rates, please confirm that a brief description of the plan will be provided.

Response

(a) The Applicant confirms it will abide by the requirements of the MAADs Handbook.

Staff-51

Reference

Timelines
Ref 1: WPI MAADs Application, p. 8
Ref 2: THI MAADs Application, p. 8

Preamble:

Both Reference 1 and 2 state that: "A subsequent deferred rebasing period may be proposed for EPC as part of Phase 2 for the combined utilities, however ERTH commits that the proposed deferred rebasing period in Phase 2 will be less than 10 years after the OEB approval of this Application".

Question

(a) Please confirm if this means that if the OEB approves the Phase 1 transactions in the 2026 calendar year, the new ERTH Power Corporation resulting from Phase 2 would rebase as a consolidated entity no later than 2036.

Response

(a) Confirmed.

Staff-52

Reference

DVA-Accounting Policy Changes
Ref 1: Handbook to Electricity Distributor and Transmitter Consolidations, July 11, 2024, section 5.9, Accounting Policy Changes
Ref 2: Westario_ERTH MAADs (EB-2026-0137) Ref 3: THI_ERTH MAADs (EB-2026-0145)

Preamble:
Per reference 1, in all MAADs applications, a consolidated utility shall establish an account to record the impact of accounting policy changes, effective at the transaction's closing date, unless the predecessor utilities provide sufficient justification as to why such an account is not needed.
OEB staff notes that the Applicant didn't propose a DVA to record the impact of accounting policy changes in reference 2 & 3.

Questions

(a) Please explain why the DVA to record the impact of accounting policy changes was not proposed in this proceeding.
(b) If the applicant decides to propose this DVA, please provide a draft accounting order for the proposed account to record the impact of accounting policy changes for the OEB's consideration in this proceeding.

References

(a) A DVA recording the impact of accounting policy changes was not proposed in this proceeding as there are no material accounting changes anticipated for the three entities.

(b) Not applicable.

Exhibit Staff-8(a)

2025 Audited Financial Statements for WPI and EPC



Financial Statements of

Westario Power Inc.

Year ended December 31, 2025

KPMG LLP
120 Victoria Street South, Suite 600
Kitchener, ON N2G 0E1
Canada
Telephone 519 747 8800
Fax 519 747 8811

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Westario Power Inc.

Opinion

We have audited the financial statements of Westario Power Inc. (the Entity), which comprise:

- the statement of financial position as at December 31, 2025
- the statement of comprehensive income for the years then ended
- the statement of changes in equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of material accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2025, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.



Chartered Professional Accountants, Licensed Public Accountants

Kitchener, Canada

April 23, 2026

WESTARIO POWER INC.

Statement of Financial Position
December 31, 2025 with comparative information for December 31, 2024

	Note	December 31, 2025	December 31, 2024
Assets			
Current assets			
Cash and cash equivalents		$ -	$ 2,317,758
Accounts receivable	5	5,784,859	5,216,552
Due from shareholders	21	382,282	327,689
Unbilled revenue		6,330,843	6,020,575
Income taxes receivable		64,860	124,930
Materials and supplies	6	193,624	208,381
Prepaid expenses		596,240	376,653
Total current assets		13,352,708	14,592,538
Non-current assets			
Property, plant and equipment	7	89,099,551	80,539,430
Intangible assets	8	2,301,577	2,338,372
Long-term asset	9	144,028	189,793
Total non-current assets		91,545,156	83,067,595
Total assets		**104,897,864**	**97,660,133**
Regulatory balances	11	9,758,350	9,980,797
Total assets and regulatory balances		**$ 114,656,214**	**$ 107,640,930**

See accompanying notes to the financial statements.

WESTARIO POWER INC.

Statement of Financial Position
December 31, 2025 with comparative information for December 31, 2024

	Note	2025	2024
Liabilities			
Current liabilities			
Bank indebtedness	22	$ 1,723,956	$ -
Accounts payable and accrued liabilities	12	8,039,449	8,414,957
Due to shareholders	21	16,214	19,471
Long-term debt due within one year	13	3,343,520	2,979,512
Customer deposits		1,365,485	2,740,498
Total current liabilities		14,488,624	14,154,438
Non-current liabilities			
Long-term debt	13,22	39,244,591	33,663,110
Post employment benefits	14	258,952	268,429
Deferred revenue		8,304,475	6,296,778
Deferred tax liabilities	10	6,066,000	5,748,000
Interest rate swap	13	1,378,639	1,589,865
Total non-current liabilities		55,252,657	47,566,182
Total liabilities		**69,741,281**	**61,720,620**
Equity			
Share capital	15	18,269,167	18,269,167
Retained earnings		25,961,355	25,666,570
Accumulated other comprehensive income (loss)		(60,772)	(58,255)
Total equity		**44,169,750**	**43,877,482**
Total liability and equity		**113,911,031**	**105,598,102**
Regulatory balances	11	745,183	2,042,828
Total liabilities, equity and regulatory balances		**$ 114,656,214**	**$ 107,640,930**

Commitments, contingencies and subsequent event (notes 7, 20 and 23)

See accompanying notes to the financial statements.

On behalf of the Board:

_____ Director
Luke Charbonneau, Board Chair

_____ Director

WESTARIO POWER INC.

Statement of Comprehensive Income
Year ended December 31, 2025, with comparative information for 2024

	Note	2025	2024
Revenue			
Sale of energy	16	64,450,127	59,394,393
Distribution revenue	16	13,111,918	12,491,232
Other	16	1,107,891	1,089,594
		78,669,936	72,975,219
Operating expenses			
Cost of power purchased		65,148,326	57,283,292
Employee salaries and benefits	17	3,492,964	3,515,329
Operating expenses	18	5,650,413	3,801,126
Depreciation and amortization		2,515,459	2,239,962
		76,807,162	66,839,709
Income from operating activities		**1,862,774**	**6,135,510**
Finance income	19	155,083	347,745
Finance costs	19	(1,973,497)	(1,760,227)
Unrealized gain (loss) on interest rate swap	13	211,226	(1,500,029)
Income before income taxes		**255,586**	**3,222,999**
Income tax expense	10	237,000	298,600
Net income for the year		**18,586**	**2,924,399**
Net movement in regulatory balances, net of tax	11	698,199	(2,111,100)
Income tax expense	10	378,000	528,000
Net income for the year and net movement in regulatory balances		**1,094,785**	**1,341,299**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurement of post-employment benefits	14	(2,517)	22,904
Tax on re-measurements	10	1,000	(6,000)
Net movement in regulatory balances, net of tax	11	(1,000)	6,000
Other comprehensive income for the year		**(2,517)**	**22,904**
Total comprehensive income for the year		**1,092,268**	**1,364,203**

See accompanying notes to the financial statements.

WESTARIO POWER INC.

Statement of Changes in Equity
Year ended December 31, 2025, with comparative information for 2024

	Share capital	Retained earnings	Accumulated other comrehensive income (loss)	Total
Balance at January 1, 2024	$ 18,269,167	$ 24,725,271	$ (81,159)	$ 42,913,279
Net income and net movement in regulatory balances	-	1,341,299	-	1,341,299
Other comprehensive income	-	-	22,904	22,904
Dividends	-	(400,000)	-	(400,000)
Balance at December 31, 2024	**$ 18,269,167**	**$ 25,666,570**	**$ (58,255)**	**$ 43,877,482**
Balance at January 1, 2025	$ 18,269,167	$ 25,666,570	$ (58,255)	$ 43,877,482
Net income and net movement in regulatory balances	-	1,094,785	-	1,094,785
Other comprehensive income	-	-	(2,517)	(2,517)
Dividends	-	(800,000)	-	(800,000)
Balance at December 31, 2025	**$ 18,269,167**	**$ 25,961,355**	**$ (60,772)**	**$ 44,169,750**

See accompanying notes to the financial statements.

WESTARIO POWER INC.

Statement of Cash Flows
Year ended December 31, 2025, with comparative information for 2024

	Note	2025	2024
Operating activities			
Net income and net movement in regulatory balances		**$ 1,094,785**	**$ 1,341,299**
Adjustments for:			
Depreciation and amortization	7,8	2,515,459	2,239,962
Amortization of deferred revenue	16	(211,462)	(155,433)
Post-employment benefits	14	(23,977)	(23,007)
Loss on disposal of property, plant, and equipment		62,219	56,086
Unrealized gain on interest rate swap		(211,226)	1,500,029
Net finance costs		1,818,414	1,412,482
Income tax expense		237,000	298,600
		5,281,212	6,670,018
Changes in non-cash operating working capital:			
Accounts receivable		(568,307)	87,823
Due to/from related parties		(57,850)	56,143
Unbilled revenue		(310,268)	(931,829)
Materials and supplies		14,757	(24,484)
Prepaid expenses and long-term asset		(173,822)	40,355
Accounts payable and accrued liabilities		(375,508)	855,251
Customer deposits		(1,375,013)	852,520
		(2,846,011)	935,779
Regulatory balances		(1,076,199)	1,583,100
Income tax paid		142,071	213,368
Interest expensed	19	(1,961,514)	(1,748,223)
Interest received	19	155,083	347,745
Net cash from operating activities		**(305,358)**	**8,001,787**
Investing activities			
Purchase of property, plant and equipment	7	(11,115,907)	(9,788,557)
Proceeds on disposal of property, plant and equipment		23,829	48,706
Purchase of intangible assets	8	(8,926)	(11,293)
Net cash used by investing activities		**(11,101,004)**	**(9,751,144)**
Financing activities			
Dividends paid		(800,000)	(400,000)
Contributions received from customers		2,219,159	887,173
Issuance of long-term debt	13	9,000,000	12,800,000
Repayment of long-term debt	13	(3,054,511)	(8,186,505)
Net cash from financing activities		**7,364,648**	**5,100,668**
Increase in cash		(4,041,714)	3,351,311
Bank indebtedness, beginning of the year		2,317,758	(1,033,553)
Cash (bank indebtedness), end of the year		**$ (1,723,956)**	**2,317,758**

See accompanying notes to the financial statements.

1. Reporting entity

Westario Power Inc. (the "Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Walkerton of the Municipality of Brockton. The address of the Corporation's registered office is 24 Eastridge Road, Walkerton, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the following communities, specifically:

- The Township of Huron-Kinloss (Villages of Ripley and Lucknow)
- The Municipality of Kincardine (Kincardine Ward 1)
- The Municipality of South Bruce (Villages of Mildmay and Teeswater)
- The Town of Saugeen Shores (Towns of Port Elgin and Southampton)
- The Township of North Huron (Town of Wingham)
- The Municipality of Brockton (Town of Walkerton and Village of Elmwood)
- The Town of Hanover (Town of Hanover)
- The Town of Minto (Towns of Harriston and Palmerston, Village of Clifford)
- The Municipality of West Grey (Village of Neustadt)

The Corporation is owned generally by the communities they serve, specifically:

- The Township of Huron-Kinloss
- The Municipality of Kincardine
- The Municipality of South Bruce
- The Town of Saugeen Shores
- The Township of North Huron
- The Municipality of Brockton
- The Town of Hanover
- The Town of Minto
- FortisOntario Inc.

The financial statements are for the Corporation as at and for the year ended December 31, 2025.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 22, 2026.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

2. Basis of presentation (continued)

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Use of estimates

The preparation of the Corporation's Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, disclosure of contingent assets and liabilities at the date of the Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy, or the Ontario Ministry of Finance. Due to current uncertain economic conditions, the estimates and judgments made by management in the preparation of the Corporation's Financial Statements are subject to uncertainty. Management has analyzed the impact of the uncertain economic conditions on its estimates and adjusted the expected credit loss allowance as at December 31, 2025. The extent of the future impact of the uncertain economic conditions on the Corporation's financial results and business operations is not known at this time.

Information about judgments in applying accounting policies that have the most material effects on the amounts recognized in the financial statements is included in note 3(j) relating to recognition of regulatory balances and note 3(c) relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively.

The following are the judgments that management has made, apart from those involving estimations, that have the most significant effect on the amounts recognized in the financial statements:

Note 3(c) - Determination of the performance obligations for contributions from customers and the related amortization period.

2. Basis of presentation (continued)

(d) Use of estimates (continued)

Note 3(c) - Principal versus agent determination for electricity revenues

Judgment is required in determining whether the Corporation acts as principal or agent for certain components of electricity revenues. In making this determination, management considers whether the Corporation controls the specified goods or services before they are transferred to customers, including responsibility for fulfillment and exposure to credit risk.

Note 11 - Recognition and recoverability of regulatory balances

The Corporation exercises significant judgment in determining whether regulatory deferral account debit balances meet the recognition criteria under IFRS 14. This includes assessing whether it is probable that future rates approved by the Ontario Energy Board ("OEB") will allow recovery of the deferred costs. The assessment is based on historical OEB decisions, existing rate orders, regulatory mechanisms available for disposition, and the nature of the underlying costs.

The following estimates and assumptions have a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year:

Note 3(c) Unbilled revenue

Unbilled revenue is estimated based on electricity delivered but not yet billed, using historical consumption patterns, seasonal factors, and weighted average pricing assumptions.

Notes 3(e), 3(f), 7, 8 Property, plant and equipment and intangible assets – useful lives

Estimates are required in determining the useful lives of property, plant and equipment and intangible assets, which directly affect depreciation and amortization expense.

Note 11 Regulatory balances – measurement

The measurement of regulatory balances requires estimates related to the amounts expected to be recovered from or refunded to customers through future rates, including assumptions regarding future electricity consumption.

Note 14 - Post-employment benefits

The measurement of post-employment benefit obligations involves actuarial assumptions, including discount rates and benefit cost trends, which are subject to market conditions.

Note 22 - Expected credit loss allowance

The expected credit loss allowance for accounts receivable and unbilled revenue is estimated using historical loss experience, current conditions, and forward-looking information, including macroeconomic factors.

2. Basis of presentation (continued)

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

Rate setting

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholders' equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation filed a Cost of Service application on November 23, 2023, for rates effective April 1, 2024 to December 31, 2024, with annual IRM filed in 2025 for effective rates starting January 1, 2026. The OEB issued a Decision to approve the Corporation's 2026 rates on December 11, 2025.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

3. Material accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements:

(a) Financial instruments

All financial assets and financial liabilities are classified as “Amortized cost”. These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of the financial instrument is the amount of consideration that would be agreed upon in an arm’s length transaction between willing parties.

The corporation uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheet:

- Cash and cash equivalents are classified as “Amortized cost” and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.
- Accounts receivable and unbilled revenue are classified as “Amortized cost” and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method, less expected credit loss allowance. The carrying amounts approximate fair value due to the short maturity of these instruments.
- Long-Term Debt and Bank indebtedness credit facilities are classified as “Amortized cost” and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the maturity of these instruments.
- Accounts payable are classified as “Amortized cost” and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.
- Customer deposits are classified as “Amortized cost” and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value considering interest accrued on the outstanding balance.
- Derivatives are initially measured at fair value; any directly attributable transaction costs are recognized in profit or loss as incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein are recognized in the statement of comprehensive income.

3. Material accounting policies (continued)

(b) Fair Value measurements

The Corporation utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets and liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and
- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

Hedge accounting has not been used in the preparation of these financial statements.

(c) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of the power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges were recorded on a net basis as the Corporation is acting as an agent for this billing stream.

3. Material accounting policies (continued)

(c) Revenue recognition (continued)

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of the construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order to receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other revenue

Revenue earned from the provision of services is recognized as the performance obligations are met. Amounts received in advance of these milestones are presented as deferred revenue.

Contract balances

Contract assets primarily relate to unbilled revenue arising from satisfied performance obligations for which the Company does not yet have an unconditional right to consideration. Due to the timing of billing cycles, these balances are typically owed and collected in full during the following year, with the new balance represent balances earned in the previous month. Contract liabilities primarily relate to deferred revenue representing capital contributions received from customers that are recognized as revenue over time as the related obligations are satisfied.

(d) Materials and supplies

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Material accounting policies (continued)

(e) Property, plant, and equipment

Items of property, plant, and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets may be capitalized as part of the cost of the asset based on the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of twelve months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

3. Material accounting policies (continued)

(e) Property, plant and equipment (continued)

The estimated useful lives are as follows:

	Years
Buildings	50
Distribution stations	45
Distribution lines, overhead	65
Distribution lines, underground	60
Distribution equipment	45 – 60
Distribution transformers	40
Meters	15 – 35
Communications equipment	10
Computer equipment	5
Office furniture	10
Tools and garage equipment	10
Trucks	10 - 15

(f) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

	Years
Computer software	5

3. **Material accounting policies (continued)**

(g) Impairment

(i) Accounts Receivable and unbilled revenue.

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for the other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through a loss allowance, If applicable, and the amount of the related impairment loss is recognized in the statement of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When the Corporation considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and the Corporation considers historical trends on the timing of recoveries and the amount of loss incurred, adjusted for forward-looking factors specific to the current economic and credit conditions.

The Corporation measures the expected credit loss allowance at an amount equal to the lifetime expected credit losses for all trade receivables that result from transactions with customers and do not contain a significant financing component. Amounts are calculated separately for exposures based on customer account status. The Corporation also adjusts the expected credit loss allowance in efforts to account for current economic conditions and events (including forward-looking macroeconomic data) and historical information (including credit agency reports, if available) (note 22). The Corporation considers the reasons for the account being past due, the characteristics of existing accounts, reasonable and supportable forecasts and other considerations that may affect the collectability of the reported amounts.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

3. Material accounting policies (continued)

(g) Impairment (continued)

(ii) Non-financial assets (continued)

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorate basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(h) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(i) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

3. Material accounting policies (continued)

(i) Regulatory balances (continued)

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

The timing of recognition of regulatory balances is subject to significant judgments. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

The regulatory balances consist of the following:

a) Deferred taxes

This regulatory balance relates to both deferred tax amounts recorded under IFRS 14 and the expected future electricity distribution rate impact to customers arising from timing differences in the recognition of deferred tax assets and liabilities.

The Corporation does not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets and liabilities.

b) Settlement variances

This account includes the variances between amounts charged by the corporation to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the corporation. The corporation has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria prescribed by the OEB.

c) Wireless attachment

This account tracks revenues and costs associated with wireless pole attachments. Revenues recorded in this account are the actual revenues received through the negotiated contracts with wireless carriers, as well as the revenues collected directly to cover the one-time costs incurred.

3. Material accounting policies (continued)

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an underfunded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss as part of operating expenses.

3. Material accounting policies (continued)

(k) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on borrowings, finance lease obligations and unwinding of the discount on provisions. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(l) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits, and temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. New accounting standards and amendments not yet adopted

At the date of authorization of these financial statements, several new, but not yet effective, Standards and amendments to existing Standards, and Interpretations have been published by the IASB. None of these Standards or amendments to existing Standards have been adopted early by the Corporation and it is still to be determined if any will have a material impact on the Corporation's financial statements.

A. Lack of Exchangeability (Amendments to IAS 21)

B. Presentation and disclosure in financial statements (IFRS 18)

In April 2024, the IASB issued IFRS 18, which replaces International Accounting Standard (IAS) 1 Presentation of Financial Statements and introduces limited amendments to IAS 7 Statement of Cash Flows. IFRS 18 aims to improve communication of financial information in the financial statements, with a focus on information about financial performance in the statement of profit or loss. To meet this objective, IFRS 18 introduces additional defined subtotals in the statement of profit or loss, disclosures about management-defined performance measures, and enhanced requirements for grouping (aggregation and disaggregation) of information. The standard is effective for annual reporting periods beginning on or after January 1, 2027, with early adoption permitted. The standard is to be applied retrospectively.

The Corporation is currently assessing the impact of adopting the above standards on the company's financial statements.

5. Accounts receivable

		2025		2024
Trade receivables	$	5,011,373	$	5,067,672
Other trade receivables		644,344		183,976
Billable work		129,142		(35,096)
	$	**5,784,859**	**$**	**5,216,552**

6. Materials and supplies

The amount of materials and supplies written down due to obsolescence in 2025 was $5,562 (2024 - $13,767).

7. Property, plant and equipment

	Land and buildings	Distribution equipment	Other fixed assets	Construction in progress	Total
Cost or deemed cost					
Balance at January 1, 2025	$ 2,945,197	$ 88,922,107	$ 5,117,542	$ 1,845,428	$ 98,830,274
Additions	-	10,202,067	861,801	52,039	11,115,907
Transfers	-	1,832,201	-	(1,832,201)	-
Disposals/retirements	-	(196,374)	(84,014)	-	(280,388)
Balance at December 31, 2025	**$ 2,945,197**	**$ 100,760,001**	**$ 5,895,329**	**$ 65,266**	**$ 109,665,793**
Balance at January 1, 2024	$ 2,945,197	$ 80,302,910	$ 4,833,453	$ 1,363,209	$ 89,444,769
Additions	-	7,346,611	596,518	1,845,428	9,788,557
Transfers	-	1,363,209	-	(1,363,209)	-
Disposals/retirements	-	(90,623)	(312,429)	-	(403,052)
Balance at December 31, 2024	**$ 2,945,197**	**$ 88,922,107**	**$ 5,117,542**	**$ 1,845,428**	**$ 98,830,274**
Accumulated depreciation					
Balance at January 1, 2025	$ 586,052	$ 15,232,531	$ 2,472,261	$ -	$ 18,290,844
Depreciation	58,389	2,042,516	368,833	-	2,469,738
Disposals/retirements	-	(110,326)	(84,014)	-	(194,340)
Balance at December 31, 2025	**$ 644,441**	**$ 17,164,721**	**$ 2,757,080**	**$ -**	**$ 20,566,242**
Accumulated depreciation					
Balance at January 1, 2024	$ 527,663	$ 13,496,049	$ 2,372,898	$ -	$ 16,396,610
Depreciation	58,389	1,785,756	348,348	-	2,192,493
Disposals/retirements	-	(49,274)	(248,985)	-	(298,259)
Balance at December 31, 2024	**$ 586,052**	**$ 15,232,531**	**$ 2,472,261**	**$ -**	**$ 18,290,844**
Carrying amounts					
At December 31, 2025	**$ 2,300,756**	**$ 83,595,280**	**$ 3,138,249**	**$ 65,266**	**$ 89,099,551**
At December 31, 2024	**2,359,145**	**73,689,576**	**2,645,281**	**1,845,428**	**80,539,430**

At December 31, 2025 land and buildings with a carrying amount of $2,300,756 (2024 - $2,359,145) are subject to a general security agreement.

During the year, borrowing costs of $nil (2024 - $nil) were capitalized as part of the cost of property, plant and equipment.

Property, plant & equipment purchase commitments outstanding as at December 31, 2025 are $65,266 (2024 - $1,845,428).

8. Intangible assets

	Goodwill	Computer software	Total
Cost or deemed cost			
Balance at January 1, 2025	$ 2,214,322	$ 1,016,008	$ 3,230,330
Additions	-	8,926	8,926
Disposals/retirements	-	-	-
Balance at December 31, 2025	**2,214,322**	**1,024,934**	**3,239,256**
Balance at January 1, 2024	2,214,322	1,004,715	3,219,037
Additions	-	11,293	11,293
Disposals/retirements	-	-	-
Balance at December 31, 2024	**$ 2,214,322**	**$ 1,016,008**	**$ 3,230,330**
Accumulated depreciation			
Balance at January 1, 2025	$ -	$ 891,958	$ 891,958
Amortization	-	45,721	45,721
Disposals/retirements	-	-	-
Balance at December 31, 2025	**-**	**937,679**	**937,679**
Balance at January 1, 2024	-	844,489	844,489
Amortization	-	47,469	47,469
Disposals/retirements	-	-	-
Balance at December 31, 2024	**-**	**891,958**	**891,958**
Carrying amounts			
At December 31, 2025	**$ 2,214,322**	**$ 87,255**	**$ 2,301,577**
At December 31, 2024	**2,214,322**	**124,050**	**2,338,372**

9. Long-term assets

Long-term assets represent prepaid regulatory costs directly attributable to the Cost-of-Service application filed in 2023. They are to be amortized over a period of 5 years stipulated by OEB filing requirements Chapter 2.

10. Income tax expense

Income tax expense is comprised of:

		2025		2024
Current tax expense	$	(82,000)	$	117,000
Prior year adjustment		-		10,000
	$	(82,000)	$	127,000
Deferred tax expense:				
Change in recognized deductible temporary differences				
Property, plant and equipment	$	393,000	$	510,000
Post-retirement benefits		3,000		3,000
Unrealized interest		57,000		(398,400)
Other		(134,000)		57,000
	$	319,000	$	171,600
Income tax expense	**$**	**237,000**	**$**	**298,600**
Other comprehensive income				
Post-retirement benefits		(1,000)		6,000
Net movement in regulatory balances		(377,000)		(534,000)
Income tax expense recognized in Statement of Comprehensive Income	**$**	**(141,000)**	**$**	**(229,400)**

Reconcilliation of effective tax rate:

		2025		2024
Income before taxes	$	951,268	$	1,134,803
Canada and Ontario statutory Income tax rates		26.5%		26.5%
Expected tax provisionon on income at statutory rates		252,000		301,000
Increase (decrease) in income taxes resulting from:				
Permanent differences		1,000		1,000
Recognized deductible temporary differences due to/from customers		(377,000)		(534,000)
Other		(17,000)		2,600
Income tax expense	**$**	**(141,000)**	**$**	**(229,400)**

Significant components of the Corporation's deferred tax balances:

	2025	2024
Deferred tax assets (liabilities):		
Property, plant and equipment	(6,443,000)	(6,050,000)
Post-employment benefits	69,000	71,000
Unrealized interest	365,000	422,000
Other	(57,000)	(191,000)
	$ (6,066,000)	**$ (5,748,000)**

11. Regulatory balances

Debit balances consist of the following:

As of December 31	2024	Balances arising in period	Recovery/ reversal	2025
Settlement variances	$ 3,890,820	$ (40,078)	$ (604,520)	$ 3,246,222
Deferred income taxes	6,054,000	377,000	-	6,431,000
LEAP	35,977	45,151	-	81,128
	$ 9,980,797	**$ 382,073**	**$ (604,520)**	**$ 9,758,350**

As of December 31	2023	Balances arising in period	Recovery/ reversal	2024
Settlement variances	$ 4,817,700	$ (672,230)	$ (254,650)	$ 3,890,820
Deferred taxes	5,520,000	534,000	-	6,054,000
Cost variances	116,233	480	(116,713)	-
LEAP	-	35,977	-	35,977
	$ 10,453,933	**$ (101,773)**	**$ (371,363)**	**$ 9,980,797**

Credit balances consist of the following:

As of December 31	2024	Balances arising in period	Recovery/ reversal	2025
Settlement variances	$ 1,967,203	$ (704,557)	$ (547,632)	$ 715,014
Smart metering entity	75,625	11,432	(56,888)	30,169
	$ 2,042,828	**$ (693,125)**	**$ (604,520)**	**$ 745,183**

As of December 31	2023	Balances arising in period	Recovery/ reversal	2024
Settlement variances	$ 399,758	$ 1,567,445	$ -	$ 1,967,203
Wireless attachment	420,482	(420,482)	-	-
Smart metering entity	118,623	24,596	(67,594)	75,625
	$ 938,863	**$ 1,171,559**	**$ (67,594)**	**$ 2,042,828**

Reconciliation between the net movements in regulatory balances shown in the regulatory debit and credit balances tables and the net movements presented on the statements of income and the consolidated statements of comprehensive income is as follows:

As of December 31	2025	2024
Total movements in regulatory debit balances	(221,446)	(479,135)
Total movements in regulatory credit balances	1,297,645	(1,103,965)
Total net movements	**$ 1,076,199**	**$ (1,583,100)**
Net movements per financial statements:		
Net movements in regulatory balances	698,199	(2,111,100)
Net movements in regulatory balances arising from deferred taxes	377,000	534,000
Net movements in regulatory balances related to OCI, net of tax	1,000	(6,000)
Total net movements per financial statements	**$ 1,076,199**	**$ (1,583,100)**

The Corporation continues to reasonably expect full recovery of regulatory balances.

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption

11. Regulatory balances (continued)

is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB-prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of twenty-five basis points. In 2025 the annual rate was 3.64% for the period from January to March, 3.165% April to June, July to September 2.91%, and 2.91% for the period from October to December.

12. Accounts payable and accrued liabilities

		2025		2024
Accounts payable - energy purchases	$	6,541,391	$	6,704,298
Payroll		195,766		202,000
Trade and other		1,302,292		1,508,659
	$	**8,039,449**	**$**	**8,414,957**

13. Long-term debt

	2025	2024
Non-revolving term installment loan #1 bearing interest at Daily compounded CORRA plus 0.8%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due July 5, 2027	328,098	519,413
Non-revolving term installment loan #4 bearing interest at Daily compounded CORRA plus 1.65%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due January 3, 2025	-	27,791
Non-revolving term installment loan #3 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due September 5, 2028	705,087	941,359
Non-revolving term installment loan #5 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due July 3, 2029	887,149	1,112,949
Non-revolving term installment loan #6 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due June 3, 2032	866,667	1,000,001
Non-revolving term installment loan #7 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due February 3, 2033	1,911,111	2,177,778
Non-revolving term installment loan #8 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due December 5, 2033	2,133,333	2,399,999
Non-revolving term installment loan #9 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due December 3, 2035	2,633,333	2,899,999
Non-revolving term installment loan #10 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due October 3, 2041	2,375,000	2,525,000
Non-revolving term installment loan #11 bearing interest at Daily compounded CORRA plus 1.00%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due August 5, 2042	2,500,000	2,650,000
Non-revolving term installment loan #12 bearing interest at Daily compounded CORRA plus 1.2%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due April 3, 2043	3,900,000	4,125,000
Non-revolving term installment loan #13 bearing interest at Daily compounded CORRA plus 1.3%, plus a credit spread adjustment of 0.295%, payable in monthly installments of principal plus interest due December 3, 2043	3,583,333	3,783,333
Non-revolving term installment loan #14 bearing interest at Daily compounded CORRA plus 1.7%, payable in monthly installments of principal plus interest due June 3, 2044	11,840,000	12,480,000
Non-revolving term installment loan #15 bearing interest at Daily compounded CORRA plus 1.7%, payable in monthly installments of principal plus interest due October 5, 2050	8,925,000	-
	42,588,111	36,642,622
Current portion of term loans:	(3,343,520)	(2,979,512)
	$39,244,591	$33,663,110

13. Long-term debt (continued)

CIBC Term secured bank loans are secured by a general security agreement conveying a security interest in the personal property of the Corporation, a first priority present and future fixed charge securing not more than $2,500,000 over the real property at 24 Eastridge Road, and acknowledgement of fire insurance, with first loss payable to CIBC.

The loan agreements contain a covenant stating that at the end of each quarter, the Corporations' current ratio must not be less than 1.1 to 1.0, otherwise the loans will be repayable on demand.

As at December 31, 2025, the Corporation was not in compliance with one of the financial covenants required under its loan agreement. The lender provided a waiver for the covenant breach and confirmed that it will not demand repayment as a result of the non-compliance. Accordingly, the loan continues to be classified in accordance with the original terms of the agreement.

Interest Rate Swaps

The Corporation uses interest rate swap agreements to manage exposure to variability in cash flows arising from floating-rate debt. The swaps are not designed to in hedge accounting relationships.

Counterparty	Related Debt		Notional Principal	Effective Fixed Rate(1)	Inception Date (2)	Maturity Date
CIBC	CIBC Term Loans #1–13	$	21,823,111	**3.540%**	**June 3, 2024**	**December 3, 2043**
CIBC	CIBC Term Loan #14-15	$	20,765,000	**3.896%**	**November 5, 2024**	**November 8, 2050**
Total – December 31, 2025		**$**	**42,588,111**			

Counterparty	Related Debt		Notional Principal	Effective Fixed Rate(1)	Inception Date (2)	Maturity Date
CIBC	CIBC Term Loans #1–13	$	24,162,622	**3.540%**	**June 3, 2024**	**December 3, 2043**
CIBC	CIBC Term Loan #14	$	12,800,000	**4.124%**	**June 3, 2024**	**June 3, 2044**
Total – December 31, 2024		**$**	**36,962,622**			

(1) Effective fixed interest rates include applicable credit spreads and are based on the Canadian Overnight Repo Rate Average (CORRA).

(2) Including subsequent amendments

The swaps entered into by the Corporation do not meet the standard to apply hedge accounting. Accordingly, the interest rate swap contract is marked to market at each year end with the gain or loss recorded in the statement of comprehensive income. The gain on the interest rate swap recognized in 2025 was $211,226 (2024 – $1,500,029 loss).

13. Long-term debt (continued)

Certain comparative amounts related to the interest rate swaps have been adjusted to reflect the correction of an immaterial item identified in the current year. The nature of the adjustment, which impacts the fair value and unrealized gain (loss) on the interest rate swaps, is not considered material on the previously issued financial statements.

The impacts of the adjustments are as follows:

As of December 31, 2024	As previously reported	Adjustment	As Adjusted
Statement of Financial Position			
Deferred tax liabilities	6,591,000	(843,000)	5,748,000
Interest rate swap	(1,589,865)	3,179,730	1,589,865
Retained Earnings	28,003,300	(2,336,730)	25,666,570
Statement of Comprehensive Income			
Unrealized gain/loss on interest rate swap	1,500,029	(3,000,058)	(1,500,029)
Income tax expense	1,094,000	(795,400)	298,600

As of January 1, 2024	As previously reported	Adjustment	As Adjusted
Statement of Financial Position			
Deferred tax liabilities	5,618,000	(47,600)	5,570,400
Interest rate swap	(89,836)	179,672	89,836
Retained Earnings	24,857,343	(132,072)	24,725,271
Statement of Comprehensive Income			
Unrealized gain/loss on interest rate swap	1,016,682	(2,033,364)	(1,016,682)
Income tax expense	1,046,000	(538,800)	507,200

Shareholder Notes

On June 5, 2024, the Corporation repaid in full the outstanding shareholders' notes of $5,260,461 and the related interest. As at December 31, 2025 the shareholders' notes balance is $nil (2024 - $Nil).

13. Long-term debt (continued)

Reconciliation of movements of liabilities to cash flows arising from financing activities:

	Current and long-term debt	Retained earnings	Total (financing cash flows)
Balance at January 1, 2025	$ 36,642,622	$ 25,666,570	
Dividends paid	-	(800,000)	(800,000)
Proceeds from issuance of long-term debt (term loan #15)	9,000,000	-	9,000,000
Repayments of long-term debt	(3,054,511)	-	(3,054,511)
Total changes from financing cash flows	**$ 5,945,489**	**$ (800,000)**	**$ 5,145,489**
Total equity-related other changes	-	1,094,785	
Balance at December 31, 2025	**$ 42,588,111**	**$ 25,961,355**	
Balance at January 1, 2024	$ 32,029,127	$ 24,725,271	
Dividends paid	-	(400,000)	(400,000)
Proceeds from issuance of long-term debt	12,800,000	-	12,800,000
Repayments of long-term debt	(8,186,505)	-	(8,186,505)
Total changes from financing cash flows	**$ 4,613,495**	**$ (400,000)**	**$ 4,213,495**
Total equity-related other changes	-	1,341,299	
Balance at December 31, 2024	**$ 36,642,622**	**$ 25,666,570**	

14. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2025, the Corporation made employer contributions of $421,452 to OMERS (2024 - $379,178), of which approximately $160,981 (2024 - $136,768) has been capitalized as part of PP&E and the remaining amount of $260,471 (2024 - $242,410) has been recognized in profit or loss. The Corporation estimates that a contribution of approximately $440,640 to OMERS will be made during the next fiscal year.

As at December 31, 2025, OMERS had approximately 665,000 members, The most recently available OMERS annual report is for the year ended December 31, 2025, which reported that the plan was 99% funded.

14. Post-employment benefits (continued)

(b) Post-employment benefits other than pension

The Corporation pays certain life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2025	2024
Defined benefit obligation, beginning of year	$ 268,429	$ 302,336
Included in profit or loss Interest cost	11,983	12,004
Included in OCI		
Actuarial (gains) losses arising from:		
Changes in actual and expected plan experience	2,517	(22,904)
Benefits paid	(23,977)	(23,007)
Defined benefit obligation, end of year	$ 258,952	$ 268,429

Actuarial assumptions	2025	2024
Discount rate	4.80%	4.60%
Salary levels	actuals	actuals

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $24,500. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $28,900.

15. Share capital

	2025	2024
Authorized:		
Unlimited number of common shares		
Issued:		
10,000 common shares	$ 18,269,167	$ 18,269,167

Dividends

The Corporation has established a dividend policy with consideration given to the cash position, the working capital requirements, the net capital expenditures requirements and other considerations from time to time.

The Corporation paid aggregate dividends in the year on common shares of $80.00 per share (2024 - $40.00), which amount to total dividends paid in the year of $800,000 (2024 - $400,000).

16. Details of revenues

Revenues consist of the following:

	2025	2024
Revenue from contract with customers		
Energy Sales	$ 64,450,127	$ 59,394,393
Distribution revenue	13,111,918	12,491,232
	$ 77,562,045	$ 71,885,625
Other revenue	1,107,891	1,089,594
Total revenues	$ 78,669,936	$ 72,975,219

Energy sales and distribution revenue by customer class are as follows:

2025	Energy sales	Distribution revenue	Total revenue from contracts with customers
Residential service	$ 29,924,433	$ 8,743,017	$ 38,667,450
General service < 50	10,926,812	2,161,611	13,088,423
General service > 50	23,257,842	1,655,037	24,912,879
Scattered Load	27,225	8,336	35,561
Sentinel	2,905	3,205	6,110
Streetlighting	310,910	540,712	851,622
Total	$ 64,450,127	$ 13,111,918	$ 77,562,045

2024	Energy sales	Distribution revenue	Total revenue from contracts with customers
Residential service	$ 27,962,804	$ 8,346,221	$ 36,309,025
General service < 50	10,588,468	2,024,257	12,612,725
General service > 50	20,512,201	1,588,347	22,100,548
Scattered Load	27,427	8,113	35,540
Sentinel	2,371	2,602	4,973
Streetlighting	301,121	521,692	822,813
Total	$ 59,394,392	$ 12,491,232	$ 71,885,624

Other revenues:

	2025	2024
Rendering of services	$ 896,429	$ 934,161
Amortization of contributions received from customers	211,462	155,433
	$ 1,107,891	$ 1,089,594

17. Employee salaries and benefits

	2025	2024
Salaries, wages and benefits	$ 3,084,095	$ 3,098,023
CPP and EI remittances	139,056	150,128
Contributions to OMERS	269,813	267,178
	$ 3,492,964	$ 3,515,329

18. Operating expenses

	2025	2024
External Services	$ 2,297,417	$ 1,786,295
Other support costs*	3,266,948	1,937,158
Losses on disposal of property, plant and equipment	86,048	77,673
	$ 5,650,413	$ 3,801,126

* Includes taxes other than income taxes, insurance, communication, utilities and general and administrative expenses.

19. Finance income and costs

	2025	2024
Finance income		
Interest income on bank deposits	$ 155,083	$ 347,745
Finance costs		
Interest expense on long-term debt	$ 1,758,290	$ 1,538,865
Interest expense on customer deposits	11,835	24,461
Net interest expense on post-employment benefits	11,983	12,004
Other	191,389	184,897
	1,973,497	1,760,227
Net finance costs recognized in profit or loss	$ 1,818,414	$ 1,412,482

20. Contingencies

Contractual Obligations

In the normal course of operations, the Corporation executes agreements that can provide for the indemnification to third parties in transactions such as service agreements and purchases of goods. Under these agreements, the Corporation agrees to indemnify the counterparty against loss or liability arising from the acts or omissions of the Corporation in relation to the agreement.

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2025, no assessments have been made.

21. Related party transactions

Transactions with Shareholders

In the ordinary course of business, the Corporation delivers electricity to the following Shareholders that are billed at prices and under terms approved by the OEB.

- The Township of Huron-Kinloss
- The Municipality of Kincardine
- The Municipality of South Bruce
- The Town of Saugeen Shores
- The Township of North Huron
- The Municipality of Brockton
- The Town of Hanover
- The Town of Minto

In the ordinary course of business, the Corporation receives and pays for services under contract for information technology from Canadian Niagara Power Inc. a subsidiary of FortisOntario Inc.

21. Related party transactions (continued)

Outstanding balances due from/(due to) related parties and shareholders are:

	2025	2024
Due from:		
Canadian Niagara Power	$ -	$ -
Township of Huron Kinloss	22,562	20,421
Municipality of Kincardine	72,896	61,282
Municipality of South Bruce	26,256	32,675
Town of Saugeen Shores	113,361	81,409
Township of North Huron	20,292	35,224
Municipality of Brockton	24,846	31,124
Town of Hanover	45,491	2,629
Town of Minto	56,578	62,925
	$ 382,282	$ 327,689
Due to:		
Canadian Niagara Power	$ (16,214)	$ (19,455)
Town of Hanover	-	(16)
	$ (16,214)	$ (19,471)
	$ 366,067	$ 308,218

22. Financial instruments and risk management

(a) Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to shareholders and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

As at December 31, 2025, all financial instruments are classified in the fair value hierarchy as level 1, except for long-term debt and interest rate swaps which is level 2.

The fair value of the long-term debt at December 31, 2025 is $42,588,111 (2024 - $36,642,622), given the nature of the instrument as it's tied to the Canadian Overnight Repo Rate Average (CORRA).

The swap agreement is measured at fair value, which is provided by a third-party banking institution, and is based on market rates at the date of the valuation.

(b) Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies, are discussed below.

Credit risk

The Corporation is exposed to the risk of counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by the Corporation in assessing and monitoring the credit exposures of counterparties.

The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. The Corporation is exposed to credit risk with respect to customer non-payment of electricity bills. The Corporation considers the current economic and credit conditions to determine the expected credit loss allowance of its accounts receivable and unbilled revenue. Due to current uncertain economic conditions, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to estimation uncertainty. The Corporation determines the expected credit loss allowance based on current estimates and assumptions, including, but not limited to, recent trends for customer collections and current and forecasted economic conditions. The Corporation continues to actively monitor its exposure to credit risk.

The Corporation obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2025, the corporation held security deposits in the amount of $422,018 (2024 - $422,338). The Corporation's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2025, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable.

22. Financial instruments and risk management (continued)

(b) Financial risks (continued)

Credit risk (continued)

The Corporation did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2025 and December 31, 2024.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2025	2024
Accounts receivable, gross		
Outstanding for not more than 30 days	5,617,952	4,994,031
Outstanding for more than 30 days	345,408	345,408
Total accounts receivable, gross	$ 5,963,360	$ 5,339,439
Unbilled revenue, gross	6,330,843	6,020,575
Expected credit loss allowance	(178,501)	(122,887)
Total accounts receivable and unbilled revenue	**12,115,702**	**11,237,127**

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered in conjunction with accounts receivable and is included in the expected credit loss allowance as at December 31, 2025 and December 31, 2024.

The Corporation has a broad base of customers. As at December 31, 2025 and December 31, 2024, the Corporation's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk.

Reconciliation between the opening and closing expected credit loss allowance balances for accounts receivable and unbilled revenue is as follows:

	2025	2024
Balance, beginning of year	$ (122,887)	$ (284,031)
Additional expected credit loss allowance	17,237	292,460
Write-offs, net of recoveries	(72,851)	(131,316)
Balance, end of year	**$ (178,501)**	**$ (122,887)**

(c) Market risks

Interest rate risk

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations (note 14(b)). The Corporation is also exposed to short-term interest rate risk on the net of cash and cash equivalents, short-term borrowings under its credit facility and customer deposits. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments and taking action as necessary to maintain an appropriate balance.

22. Financial instruments and risk management (continued)

(d) Market risks (continued)

Interest rate risk (continued)

As at December 31, 2025, aside from the post-employment benefit obligations, most of the Corporation's remaining obligations were either non-interest bearing, bear fixed interest rates or protected by the swap agreement. Its financial assets were predominantly short-term in nature and mostly non-interest bearing. Fluctuations in interest rates as at December 31, 2025 would have no effect on the Corporation as long-term debt is not subject to variable interest rates due to the swap agreement in place.

Liquidity risk

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and debt capital markets and monitors cash balances daily. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they become due while minimizing finance costs. The Corporation relies on debt financing through the debt capital markets and existing credit facilities to finance its daily operations, repay existing indebtedness and fund capital expenditures. The current challenging economic climate affected by factors including, but not limited to, uncertain macroeconomic conditions like a global recession may lead to material adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct negative impact on the Corporation's operating results and financial position in the future. Accordingly, the Corporation continues to monitor liquidity risk and adapt its plans as the economic climate evolves.

Liquidity risks associated with financial commitments are as follows:

	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due within 6-20 years $
Bank indebtedness	1,723,956	-	-	-	-	-
Accounts payable and accrued liabilities	8,056,587	-	-	-	-	-
Due to shareholders	16,214	-	-	-	-	-
Long-term debt due within one year	3,343,520	-	-	-	-	-
Interest payments	1,319,655	1,210,957	1,101,528	1,002,446	897,882	4,553,711
Shareholders loans	-	-	-	-	-	-
Long-term debt	-	2,983,520	2,925,133	2,753,496	2,451,518	28,130,924
Total	**14,459,932**	**4,194,477**	**4,026,661**	**3,755,942**	**3,349,400**	**32,684,635**

The Corporation has access to a $5.2 million credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. The line of credit bears interest at the bank's prime rate. The credit facility is secured by a general security agreement conveying a security interest in the personal property of the Corporation. As at December 31, 2025, $1,723,956 (2024 - $nil) has been drawn under the Corporation's $5.2 million credit facility.

22. Financial instruments and risk management (continued)

(d) Market risks (continued)

Liquidity risk (continued)

The Corporation as part of its credit facility also has a bilateral facility for $1,897,399 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $1,897,399 has been drawn and posted with the IESO (2024 - $1,897,399).

The Corporation as part of its credit facility also has a standby letter of credit for $100,000 (the "LC" facility) for the purpose of issuing letters of credit to the Ministry of Environment with regards to compliance under the terms of the Provisional Certificate of Approval for Waste Management System. Currently $100,000 has been drawn and posted with the Ministry of Environment (2024 - $100,000).

The majority of accounts payable, as reported on the statement of financial position, are due within thirty days.

Inflation risk

The general rate of inflation in Canada decreased in 2025 compared to 2024. However, the inflation rate continues to remain close to or slightly higher than the Bank of Canada's target rate of 2.0%. Certain underlying factors such as global supply chain disruptions, shipping restrictions and labour market constraints are improving; however, the global economic conditions remain uncertain. Prices for certain services and materials continue to evolve in response to fast-changing commodity markets, industry activities, supply chain dynamics, and government policies impacting operating and capital costs. The Corporation remains exposed to inflationary pressures and a higher interest rate environment, which could have a material adverse effect on the Corporation's business, financial condition or results of operations. The Corporation closely monitors market trends and seeks to mitigate cost impacts through various measures, including project management, procurement and other management actions.

Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholders' equity and long-term debt. As at December 31, 2025, shareholders' equity amounts to $43,185,750 (2024 - $46,780,212) and long-term debt amounts to $39,244,591 (2024 - $33,663,110).

Foreign exchange risk

As at December 31, 2025, the Corporation had limited exposure to the changing values of foreign currencies.

23. Subsequent Event

On August 18, 2025, the Corporation entered into a non-binding Letter of Intent ("LOI") with ERTH Corporation outlining the preliminary terms for a potential sale of the Corporation. During the year, shareholders approved proceeding with the proposed transaction. The final Sale and Purchase Agreement ("SPA") was executed subsequent to year-end in 2026. Completion of the transaction remains subject to approval by the Ontario Energy Board ("OEB") in accordance with the Ontario Energy Board Act, 1998, including the application of the OEB's "no harm" test.

During the year ending December 31, 2025, the Corporation incurred $1,019,933 of transaction-related costs, which were expensed in the statement of comprehensive income.

As at the date the financial statements OEB approval had not been received and the transaction had not closed.

ERTH POWER CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2025

ERTH POWER CORPORATION
INDEX TO FINANCIAL STATEMENTS
DECEMBER 31, 2025

	Page
Independent Auditor's Report	1 - 3
Statement of Financial Position	4 - 5
Statement of Comprehensive Income	6
Statement of Changes in Equity	7
Statement of Cash Flows	8
Notes to the Financial Statements	9 - 39

KPMG LLP
140 Fullarton Street, Suite 1400
London, ON N6A 5P2
Canada
Telephone 519 672 4880
Fax 519 672 5684

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of ERTH Power Corporation.

Opinion

We have audited the financial statements of ERTH Power Corporation (the Entity), which comprise:

- the statement of financial position as at December 31, 2025
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2025, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information, other than the financial statements and the auditor's report thereon, included in Management's Discussion and Analysis as at the date of this auditor's report.

If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

London, Canada

April 29, 2026

ERTH POWER CORPORATION
STATEMENT OF FINANCIAL POSITION
AS AT DECEMBER 31, 2025
WITH COMPARATIVE INFORMATION FOR 2024

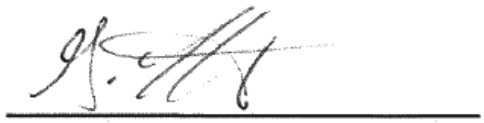
		2025	2024
Assets			
Current assets			
Accounts receivable	5	$ 9,409,010	$ 8,727,572
Unbilled revenue		9,462,343	8,022,626
Due from related parties	27	283,101	224,729
Materials and supplies	6	260,683	262,136
Prepaid expenses		1,314,394	1,052,376
Total current assets		20,729,531	18,289,439
Non-current assets			
Property, plant and equipment	8	108,887,750	85,603,163
Intangible assets	9	4,937,406	4,950,121
Investment	7	33,072	32,945
Total non-current assets		113,858,228	90,586,229
Total assets		134,587,759	108,875,668
Regulatory balances	11	7,858,038	10,348,498
Total assets and regulatory balances		$142,445,797	$119,224,166

ERTH POWER CORPORATION
STATEMENT OF FINANCIAL POSITION
AS AT DECEMBER 31, 2025
WITH COMPARATIVE INFORMATION FOR 2024

		2025	2024
Liabilities			
Current liabilities			
Bank indebtedness	12	$ 9,333,496	$ 9,852,811
Accounts payable and accrued liabilities	13	16,115,750	12,066,007
Payments in lieu of income taxes payable		95,589	79,958
Due to related parties	27	2,054,020	2,068,335
Long-term debt due within one year	14	465,799	353,475
Customer deposits	15	1,373,383	1,400,835
Deferred revenue	16	302,505	287,878
Total current liabilities		29,740,542	26,109,299
Non-current liabilities			
Long-term debt	14	47,408,179	32,365,094
Interest rate swaps	14	580,057	432,475
Post-employment benefits	17	1,119,100	1,112,800
Customer deposits	15	1,067,619	117,731
Deferred revenue	16	16,390,865	15,823,037
Deferred tax liabilities	10	3,392,000	3,168,000
Total non-current liabilities		69,957,820	53,019,137
Total liabilities		99,698,362	79,128,436
Equity			
Share capital	18	14,265,677	14,265,677
Retained earnings		22,524,421	20,429,341
Contributed capital		4,649,139	4,649,139
Accumulated other comprehensive loss		(396,299)	(351,126)
Total equity		41,042,938	38,993,031
Total liabilities and equity		140,741,300	118,121,467
Regulatory balances	11	1,704,497	1,102,699
Total liabilities, equity and regulatory balances		$142,445,797	$119,224,166

Contingencies (note 24)
Guarantee (note 25)
Commitments (note 8 and 26)

APPROVED ON BEHALF OF THE BOARD:



Director



Director

ERTH POWER CORPORATION
STATEMENT OF COMPREHENSIVE INCOME
FOR THE YEAR ENDED DECEMBER 31, 2025
WITH COMPARATIVE INFORMATION FOR 2024

		2025	2024
Revenues			
Sale of energy	19	$77,641,595	$71,777,139
Distribution revenue	19	16,363,324	15,515,007
Other	20	922,538	802,488
		94,927,457	88,094,634
Operating expenses			
Cost of power purchased		74,023,906	70,284,643
Employee salaries and benefits	21	3,643,616	3,263,947
Operating expenses	22	5,904,046	5,149,471
Depreciation and amortization	8,9	3,349,530	3,164,191
		86,921,098	81,862,252
Income from operations		8,006,359	6,232,382
Finance costs	23	2,222,021	2,810,104
Income before income taxes		5,784,338	3,422,278
Income tax expense	10	609,000	639,000
Net income for the year		5,175,338	2,783,278
Net movement in regulatory balances, net of tax	11	(3,080,258)	(966,471)
Net income for the year and net movement in regulatory balances		**2,095,080**	**1,816,807**
Other comprehensive income			
Items that will be reclassified to profit or loss:			
Change in fair value of investments		127	6,419
Items that will not be reclassified to profit or loss:			
Remeasurement of post-employment benefits	17	(45,300)	16,900
Tax on remeasurements	10	12,000	(6,000)
Net movement in regulatory balances, net of tax	11	(12,000)	6,000
Other comprehensive income		(45,173)	23,319
Total comprehensive income for the year		**$ 2,049,907**	**$ 1,840,126**

ERTH POWER CORPORATION
STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2025
WITH COMPARATIVE INFORMATION FOR 2024

	Share capital	Retained earnings	Contributed capital	Accumulated other comprehensive loss	Total
Balance at January 1, 2024	$ 14,265,677	$ 18,612,534	$ 4,649,139	$ (374,445)	$ 37,152,905
Net income and net movement in regulatory balances	-	1,816,807	-	-	1,816,807
Other comprehensive income	-	-	-	23,319	23,319
Balance at December 31, 2024	$ 14,265,677	$ 20,429,341	$ 4,649,139	$ (351,126)	$ 38,993,031
Balance at January 1, 2025	$ 14,265,677	$ 20,429,341	$ 4,649,139	$ (351,126)	$ 38,993,031
Net income and net movement in regulatory balances	-	2,095,080	-	-	2,095,080
Other comprehensive income (loss)	-	-	-	(45,173)	(45,173)
Balance at December 31, 2025	$ 14,265,677	$ 22,524,421	$ 4,649,139	$ (396,299)	$ 41,042,938

ERTH POWER CORPORATION
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2025
WITH COMPARATIVE INFORMATION FOR 2024

	2025	2024
Operating activities		
Net income and net movement in regulatory balances	$ 2,095,080	$ 1,816,807
Adjustments for:		
Depreciation and amortization	3,349,530	3,164,191
Amortization of deferred revenue	(295,192)	(256,084)
Post-employment benefits	(39,000)	(10,200)
Gain on disposal of property, plant and equipment	(51,761)	(361,483)
Net finance costs	2,222,021	2,810,104
Income tax expense	609,000	639,000
	7,889,678	7,802,335
Changes in non-cash operating working capital:		
Accounts receivable	(681,438)	(606,044)
Due to related parties	(72,687)	48,927
Unbilled revenue	(1,439,717)	(1,875,887)
Materials and supplies	1,453	2,073
Prepaid expenses	(262,018)	(458,894)
Accounts payable and accrued liabilities	4,049,743	1,000,685
Customer deposits	922,436	(1,398,842)
	2,517,772	(3,287,982)
Regulatory balances	3,092,258	960,471
Income tax paid	(369,369)	(343,654)
Net cash from operating activities	13,130,339	5,131,170
Investing activities		
Purchase of property, plant and equipment	(26,570,857)	(16,941,872)
Proceeds on disposal of property, plant and equipment	51,761	2,111,816
Purchase of intangible assets	(50,545)	(77,082)
Net cash used by investing activities	(26,569,641)	(14,907,138)
Financing activities		
Contributions received from customers	877,647	3,815,278
Finance costs	(2,074,439)	(2,377,629)
Proceeds from issuance of long-term debt	14,054,874	18,942,350
Proceeds from issuance of finance leases	1,574,054	-
Repayment of long-term debt	(273,867)	(15,622,700)
Repayment of finance leases	(199,652)	(2,339,041)
Net cash from financing activities	13,958,617	2,418,258
Change in cash (bank indebtedness)	519,315	(7,357,710)
Bank indebtedness, beginning of year	(9,852,811)	(2,495,101)
Bank indebtedness, end of year	$ (9,333,496)	$ (9,852,811)

1. Reporting entity

ERTH Power Corporation is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Ingersoll. The address of the Corporation's registered office is 143 Bell Street, PO Box 157 Ingersoll ON (Canada) N5C 3K5.

The Corporation delivers electricity and related energy services to residential and commercial customers in Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, Thamesford, Clinton, Mitchell, Dublin and Goderich. The Corporation is wholly owned by ERTH Corporation which is wholly owned by the following nine municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra, West Perth and Goderich.

The financial statements are for the Corporation as at and for the year ended December 31, 2025.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 23, 2026.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Use of estimates

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued)

(d) Use of estimates (continued)

(i) Assumptions and estimation uncertainty (continued)

Information about assumptions and estimation uncertainties are included in the financial statements in the following notes:

(i) Notes 3(d), 3(e), 8, 9 – estimation of useful lives of its property, plant and equipment and estimation of fair value of goodwill and intangible assets
(ii) Note 3(k) – measurement of leases: discount rate
(iii) Note 3(m) – income taxes
(iv) Note 10 – income tax expense
(v) Note 17 – measurement of defined benefit obligations: key actuarial assumptions
(vi) Note 24 – recognition and measurement of provisions and contingencies
(vii) Note 28 – estimation for allowance for doubtful accounts

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the non-consolidated financial statements are included in the following notes:

(i) Note 3(k) – leases: whether an arrangement contains a lease
(ii) Note 3(k) – leases: lease term, underlying leased asset value
(iii) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period
(viii) Note 3(m) – income taxes
(ix) Note 10 – income tax expense
(iv) Note 11 - recognition and measurement of regulatory balances

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board (“OEB”), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfil obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting

Distribution revenue

For its distribution revenue, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholders' equity required to support the Corporation’s business. The Corporation forecasts electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review. The Corporation is currently within an OEB approved deferral window for COS filing having recently merged with West Coast Huron Energy. The Corporation’s next COS application in 2028, filed 8 years after the merger will be an application to harmonize rate structures between the two areas.

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“GDP IPI-FDD”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application on September 15, 2017 for rates effective January 1, 2019 to April 30, 2019. On November 5, 2019 the Corporation filed an IRM application with the OEB for its Main rate zone for rates effective May 1, 2020 until April 30, 2021. Within this application the approved GDP IPI-FDD is 2.00%, the Corporations productivity factor is 0.00% and the stretch factor us 0.30% resulting in a net increase of 1.70% to previous years rates. On November 25, 2020 the Corporation filed an IRM application with the OEB for rates effective May 1, 2021 until April 30, 2022. Within this application the approved GDP IPI-FDD is 2.20%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 1.90% to the previous year’s rates. On November 23, 2021 the Corporation filed an IRM application with the OEB for rates effective May 1, 2022 until April 30, 2023. Within this application the approved GDP IPI-FDD is 3.30%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 3.00% to the previous year’s rates. On November 23, 2022 the Corporation filed an IRM application with the OEB for rates effective May 1, 2023 until April 30, 2024. Within this application the approved GDP IPI-FDD is 3.70%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 3.40% to the previous year’s rates. On November 3, 2023 the Corporation filed an IRM application with the OEB for rates effective May 1, 2024 until April 30, 2025. Within this application the approved GDP IPI-FDD is 4.80%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 4.50% to the previous year’s rates. On October 11, 2024 the Corporation filed an IRM application with the OEB for rates effective May 1, 2025 until April 30, 2026. Within this application the approved GDP IPI-FDD is 3.60%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 3.30% to the previous year’s rates.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

The Corporation last filed a COS application for its Goderich Rate Zone on November 16, 2012 for rates effective May 1, 2013 to April 30, 2014. On November 5th 2019 the Corporation filed an IRM application with the OEB for its Goderich rate zone for rates effective May 1, 2020 until April 30, 2021. Within this application the approved GDP IPI-FDD is 2.00%, the Corporations productivity factor is 0.00% and the stretch factor us 0.60% resulting in a net increase of 1.40% to previous years rates. On November 25, 2020 the Corporation filed an IRM application with the OEB for rates effective May 1, 2021 until April 30, 2022. Within this application the approved GDP IPI-FDD is 2.20%, the Corporation's productivity factor is 0.00% and the stretch factor is 0.60%, resulting in a net increase of 1.60% to the previous year's rates. On November 23, 2021 the Corporation filed an IRM application with the OEB for rates effective May 1, 2022 until April 30, 2023. Within this application the approved GDP IPI-FDD is 3.30%, the Corporation's productivity factor is 0.00% and the stretch factor is 0.60%, resulting in a net increase of 2.70% to the previous year's rates. On November 23, 2022 the Corporation filed an IRM application with the OEB for rates effective May 1, 2023 until April 30, 2024. Within this application the approved GDP IPI-FDD is 3.70%, the Corporation's productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 3.40% to the previous year's rates. On November 3, 2023 the Corporation filed an IRM application with the OEB for rates effective May 1, 2024 until April 30, 2025. Within this application the approved GDP IPI-FDD is 4.80%, the Corporation's productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 4.50% to the previous year's rates. On October 11, 2024 the Corporation filed an IRM application with the OEB for rates effective May 1, 2025 until April 30, 2026. Within this application the approved GDP IPI-FDD is 3.60%, the Corporation's productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 3.30% to the previous year's rates.

Electricity rates

The OEB sets electricity prices for low-volume consumers once each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

The OEB has a decision and order in place banning utilities in Ontario from disconnecting homes for nonpayment during the winter. This ban is in place from November 15 to April 30 each year.

3. Material accounting policies

The material accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments

Non-derivative

All financial assets are classified as loans and receivables and all financial liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(d).

Financial assets and financial liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument.

3. Material accounting policies (continued)

(a) Financial instruments (continued)

Non-derivative (Continued)

Trade receivables are initially measured at the invoiced amount. All other financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issuance of financial assets and financial liabilities (other than financial assets and financial liabilities at fair value through profit or loss ("FVTPL")) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognized immediately in profit or loss.

Financial assets - Recognition and de-recognition

All financial assets are recognized and de-recognized on the trade date. The Corporation determines the classification of its financial assets on the basis of both the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset. Financial assets are not reclassified subsequent to their initial recognition unless the Corporation changes its business model for managing financial assets. A financial asset is measured at amortized cost if it is held within a business model whose objective is to hold assets to collect contractual cash flows, and its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Financial assets - Subsequent measurement

Financial assets at amortized cost are measured using the effective interest method, less any impairment. Interest income is recognized by applying the effective interest rate except for short-term receivables where the interest revenue would be immaterial. Interest income, foreign exchange gains and losses, impairment, and any gain or loss on de-recognition are recognized in profit or loss. Financial assets at FVTPL are measured at fair value. Net changes in the fair value are recognized in profit or loss. Financial assets at fair value through other comprehensive income ("FVOCI") are measured at fair value. Net changes in the fair value are recognized in other comprehensive income.

Financial assets - Impairment

The Corporation applies the expected credit loss model to financial assets at amortized cost, contract assets and debt instruments measured at FVOCI. The Corporation measures loss allowances at an amount equal to the lifetime expected credit losses ("ECLs") in accordance with the 'simplified approach' available under the standard. Under this approach, loss allowances on trade accounts receivable are always measured at lifetime ECLs. When determining whether the credit risk of a financial asset has increased significantly since initial recognition and when estimating ECLs, the Corporation considers reasonable and supportable information that is relevant and available without undue cost or effort. This includes both quantitative and qualitative information and analysis, based on the Corporation's historical experience and informed credit assessment and includes forward-looking information.

3. Material accounting policies (continued)

(a) Financial instruments (continued)

Financial liabilities - Recognition and de-recognition

The Corporation de-recognizes financial liabilities when the Corporation's obligations are discharged, cancelled or they expire.

Financial liabilities - Subsequent measurement

Financial liabilities at amortized cost are measured using the effective interest rate method.

Classification under IFRS 9

The Corporation uses the following methods and assumptions to estimate the fair value of each class of nonderivative financial instruments for which carrying amounts are included in the consolidated balance sheets:

- Cash and cash equivalents are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method, less expected credit loss allowance. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Amortized cost" and is initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of the instruments.

- The uncommitted operating revolving loan facility is classified as "Amortized cost" and initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable and accrued liabilities, payments in lieu of income taxes payable, dividends payable, due to related parties, lease liabilities and deferred revenue are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

- Long-term debt is classified as "Amortized cost" and is initially measured at fair value. The carrying amounts approximate fair value because of the nature of the instruments. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

- Customer and other deposits are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value considering interest accrued on the outstanding balance.

3. Material accounting policies (continued)

(a) Financial instruments (continued)

Derivatives

Derivatives are initially measured at fair value and any attributable transaction costs are recognized in profit or loss as incurred. Subsequent to initial recognition, derivatives are measured at fair value and changes therein are recognized in profit or loss. Embedded derivatives are separated from the host contract upon initial recognition and accounted for separately at FVTPL when the host contract is not a financial asset and certain conditions are met. The Corporation does not use derivative instruments for speculative purposes.

The Corporation holds derivative financial instruments to manage its interest rate risk exposures. Derivatives are initially recognized at fair value; any directly attributable transaction costs are recognized in the Statement of Comprehensive Income as incurred as a change in interest rate swap. Subsequent to initial recognition, derivatives are measured at fair value using level 2 inputs, and changes therein are recognized in the Statement of Comprehensive Income.

Hedge accounting has not been used in the preparation of these financial statements.

Fair value measurements

The Corporation utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: unadjusted quoted prices in active markets for identical assets or liabilities. The Corporation does not use Level 1 inputs for its fair value measurements.

- Level 2: inputs, other than quoted prices in active markets, that are observable for the asset or liability either directly or indirectly. The Corporation's Level 2 inputs include quoted market prices for interest rates and credit risk premiums. The Corporation obtains information from sources including the Bank of Canada and market exchanges. The Corporation uses Level 2 inputs for all of its financial instrument fair value measurements.

- Level 3: inputs that are not based on observable market data. The Corporation does not use Level 3 inputs for any of its fair value measurements.

3. Material accounting policies (continued)

(b) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions are initially recorded under current liabilities as customer deposits. Once the distribution system asset is completed or modified, as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

(c) Materials and supplies

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Material accounting policies (continued)

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

	Years
Buildings	55 - 60
Automotive equipment	8 - 10
Computer equipment	5 - 15
Services, office and other equipment	5 - 15
Transmission and distribution system	12 - 60

3. Material accounting policies (continued)

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

Goodwill represents the excess of cost over fair value of net assets of businesses acquired. Goodwill is measured at cost less accumulated impairment losses.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate.

The estimated useful lives are as follows:

	Years
Computer software	3 - 15
Goodwill	indefinite life
Land rights	indefinite life

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset’s carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

3. Material accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorate basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service. Deposits that are refundable upon demand are classified as a current liability.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

3. Material accounting policies (continued)

(i) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

3. Material accounting policies (continued)

(j) Post-employment benefits (continued)

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses, are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in statement of comprehensive income.

(k) Leased assets

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

3. Material accounting policies (continued)

(k) Leased assets (continued)

All other leases are classified as operating leases and the leased assets are not recognized on the Corporation's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

(l) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on borrowings, finance lease obligations, interest on customer deposits and unwinding of the discount on provisions. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes ("PILs") are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. Standards issued but not yet adopted

Future accounting changes

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. The Corporation is still evaluating the adoption of the following new and revised standards along with any subsequent amendments.

(a) *Presentation and Disclosure in Financial Statements (IFRS 18)*

In April 2024, the IASB issued IFRS 18 Presentation and Disclosure in Financial Statements (IFRS 18), which replaces IAS 1 and introduces limited amendments to IAS 7 Statement of Cash Flows. IFRS 18 aims to improve communication of financial information in the financial statements, with a focus on information about financial performance in the statement of profit or loss. To meet this objective, IFRS 18 introduces additional defined subtotals in the statement of profit or loss, disclosures about management-defined performance measures, and enhanced requirements for grouping (aggregation and disaggregation) of information. The standard is effective for annual reporting periods beginning on or after January 1, 2027, with early adoption permitted. The standard is to be applied retrospectively.

The Company intends to adopt this standard in its financial statements for the annual period beginning January 1, 2027. The extent of the impact of adoption of the standard has not yet been determined.

(b) *Classification and Measurement of Financial Instruments (Amendments to IFRS 9 Financial Instruments (IFRS 9) and IFRS 7 Financial Instruments: Disclosures (IFRS 7*)

In May 2024, the IASB issued amendments to IFRS 9 and IFRS 7 relating to the classification and measurement of financial instruments. The amendments clarify that a financial liability is derecognized on the 'settlement date' and introduce an accounting policy choice to derecognize financial liabilities settled using an electronic payment system before the settlement date, if specified criteria are met. Other clarifications include the classification of financial assets with environmental, social, and governance linked features and other similar contingent features, financial assets with non-recourse features, and contractually linked instruments. The amendments also introduce additional disclosures for financial instruments with contingent features and equity instruments designated at fair value through OCI. The amendments are effective for annual reporting periods beginning on or after January 1, 2026, with early adoption permitted. The amendments are to be applied retrospectively.

The Company intends to adopt this standard in its financial statements for the annual period beginning January 1, 2026. The extent of the impact of adoption of the standard has not yet been determined.

5. Accounts receivable

	2025	2024
Trade receivables	$ 9,036,567	$ 7,736,222
Billable work	372,443	991,350
	$ 9,409,010	$ 8,727,572

6. Materials and supplies

Amounts written down due to obsolescence in 2025 was nil (2024 - nil).

7. Investment

The Corporation holds 386 Common shares of Sunlife Financial with a fair value at December 31, 2025 of $33,072 (2024 - $32,945).

8. Property, plant and equipment

	Land and buildings	Distribution equipment	Other fixed assets	Construction in progress	Total
Cost or deemed cost					
Balance at Jan. 1, 2025	$ 1,071,240	$ 86,371,899	$ 5,158,669	$ 10,168,810	$ 102,770,618
Additions	1,579,716	35,026	868,858	24,087,257	26,570,857
Transfers	-	5,959,183	-	(5,959,183)	-
Disposals/retirements	-	(216,450)	-	-	(216,450)
Balance at Dec. 31, 2025	$ 2,650,956	$ 92,149,658	$ 6,027,527	$ 28,296,884	$ 129,125,025
Balance at Jan. 1, 2024	$ 3,976,820	$ 80,991,968	$ 4,974,599	$ 2,370,513	$ 92,313,900
Additions	10,697	260,010	492,761	16,178,404	16,941,872
Transfers	-	8,120,098	260,009	(8,380,107)	-
Disposals/retirements	(2,916,277)	(3,000,177)	(568,700)	-	(6,485,154)
Balance at Dec. 31, 2024	$ 1,071,240	$ 86,371,899	$ 5,158,669	$ 10,168,810	$ 102,770,618
Accumulated depreciation					
Balance at Jan. 1, 2025	$ 510,539	$ 13,749,770	$ 2,907,146	$ -	$ 17,167,455
Depreciation	245,953	2,282,069	758,248	-	3,286,270
Disposals/retirements	-	(216,450)	-	-	(216,450)
Balance at Dec. 31, 2025	$ 756,492	$ 15,815,389	$ 3,665,394	$ -	$ 20,237,275
Balance at Jan. 1, 2024	$ 1,394,832	$ 14,568,632	$ 2,831,229	$ -	$ 18,794,693
Depreciation	281,651	2,181,315	644,617	-	3,107,583
Disposals/retirements	(1,165,944)	(3,000,177)	(568,700)	-	(4,734,821)
Balance at Dec. 31, 2024	$ 510,539	$ 13,749,770	$ 2,907,146	$ -	$ 17,167,455
Carrying amounts					
At December 31, 2025	$ 1,894,464	$ 76,334,269	$ 2,362,133	$ 28,296,884	$ 108,887,750
At December 31, 2024	560,701	72,622,129	2,251,523	10,168,810	85,603,163

At December 31, 2025, land and buildings include right-of-use assets related to lease of office space with the cost of $2,362,944 (2024 - $783,228), accumulated depreciation of $694,255 (2024 - $452,837) and carrying amount of $1,668,689 (2024 - $330,391). For the year ended December 31, 2025, the Corporation recorded deprecation expense of $241,419 (2024 - $277,117) related to the right-of-use assets.

The corresponding finance lease obligation for the right of use assets has been disclosed in note 14.

At December 31, 2025 all current and future personal property including property, plant and equipment with with a carrying amount of $107,219,061 (2024 - $85,272,772) are subject to a general security agreement.

During the year, borrowing costs of $616,743 (2024 - $273,386) were capitalized as part of were capitalized as part of construction in process.

Property, plant and equipment and intangible asset purchase commitments outstanding as at December 31, 2025 are $7,711,090 (2024 - $18,927,792).

9. Intangible assets

	Computer software	Land rights	Goodwill	Total
Cost or deemed cost				
Balance at Jan. 1, 2025	$ 543,018	$ 50,641	$ 4,793,925	$ 5,387,584
Additions	50,545	-	-	50,545
Balance at Dec. 31, 2025	$ 593,563	$ 50,641	$ 4,793,925	$ 5,438,129
Balance at Jan. 1, 2024	$ 505,923	$ 50,641	$ 4,793,925	$ 5,350,489
Additions	77,082	-	-	77,082
Disposals/retirements	(39,987)	-	-	(39,987)
Balance at Dec. 31, 2024	$ 543,018	$ 50,641	$ 4,793,925	$ 5,387,584
Accumulated amortization				
Balance at Jan. 1, 2025	$ 437,463	$ -	$ -	$ 437,463
Amortization	63,260	-	-	63,260
Balance at Dec. 31, 2025	$ 500,723	$ -	$ -	$ 500,723
Balance at Jan. 1, 2024	$ 420,841	$ -	$ -	$ 420,841
Amortization	56,609	-	-	56,609
Disposals/retirements	(39,987)	-	-	(39,987)
Balance at Dec. 31, 2024	$ 437,463	$ -	$ -	$ 437,463
Carrying amounts				
At December 31, 2025	$ 92,840	$ 50,641	$ 4,793,925	$ 4,937,406
At December 31, 2024	105,555	50,641	4,793,925	4,950,121

10. Income tax expense

	2025	2024
Current tax expense	$ 373,000	$ 464,000
Deferred tax expense		
Change in recognized deductible temporary differences	236,000	175,000
Total current and deferred income tax in profit or loss, before movement of regulatory balances	609,000	639,000
Other comprehensive income:		
Other	-	2,000
Post-employment benefits	(12,000)	4,000
	(12,000)	6,000
Total current and deferred tax, before movement of regulatory balances	597,000	645,000
Net movement in regulatory balances	(378,000)	(181,000)
Income tax expenses recognized in statement of comprehensive income	$ 219,000	$ 464,000

10. Income tax expense (continued)

Reconciliation of effective tax rate

	2025	2024
Income before taxes	$ 2,268,907	$ 2,304,126
Canada and Ontario statutory income tax rates	26.5 %	26.5 %
Expected tax provision on income at statutory rates	601,000	611,000
Increase (decrease) in income taxes resulting from:		
Permanent difference	(3,000)	22,000
Recognized deductible temporary differences due to/from customers	(378,000)	(181,000)
Other	(1,000)	12,000
Income tax expense	$ 219,000	$ 464,000

Significant components of the Corporation's deferred tax balances

	2025	2024
Deferred tax (liabilities) assets:		
Property, plant, equipment and intangible assets	$ (3,845,000)	$ (3,539,000)
Post-employment benefits	297,000	295,000
Other	156,000	76,000
	$ (3,392,000)	$ (3,168,000)

11. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances.

	January 1, 2025	Additions	Recovery/ (reversal)	December 31, 2025
Regulatory deferral account debit balances				
Regulatory assets account	$ 4,136,634	$ 118,275	$ (1,417,704)	$ 2,837,205
Regulatory settlement account	2,664,109	(2,300,918)	670,715	1,033,906
Regulatory adjustments	67,815	-	-	67,815
Other regulatory accounts	311,940	61,172	-	373,112
Deferred income tax	3,168,000	378,000	-	3,546,000
	$ 10,348,498	$ (1,743,471)	$ (746,989)	$ 7,858,038

All regulatory deferral account debit balances have a remaining recovery reversal of 1 year.

	January 1, 2024	Additions	Recovery/ (reversal)	December 31, 2024
Regulatory deferral account debit balances				
Regulatory settlement account	$ 5,865,705	$ 1,012,178	$ (2,741,249)	$ 4,136,634
Regulatory asset account	2,615,487	(2,599,073)	2,647,695	2,664,109
Regulatory adjustments	67,815	-	-	67,815
Other regulatory accounts	261,294	50,646	-	311,940
Deferred income tax	2,987,000	181,000	-	3,168,000
	$ 11,797,301	$ (1,355,249)	$ (93,554)	$ 10,348,498

All regulatory deferral account debit balances have a remaining recovery reversal of 1 year.

11. Regulatory balances (continued)

	January 1, 2025	Additions	Recovery/ (reversal)	December 31, 2025
Regulatory deferral account credit balances				
Regulatory liability account	$ 630,151	$ 1,261,281	$ (747,516)	$ 1,143,916
Other regulatory accounts	472,548	88,033	-	560,581
	$ 1,102,699	$ 1,349,314	$ (747,516)	$ 1,704,497

All regulatory deferral account credit balances have a remaining recovery reversal of 1 year.

	January 1, 2024	Additions	Recovery/ (reversal)	December 31, 2024
Regulatory deferral account credit balances				
Regulatory liability account	$ 1,204,125	$ (480,420)	$ (93,554)	$ 630,151
Other regulatory accounts	386,907	85,641	-	472,548
	$ 1,591,032	$ (394,779)	$ (93,554)	$ 1,102,699

All regulatory deferral account credit balances have a remaining recovery reversal of 1 year.

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from or paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers Acceptances three-month rate plus a spread of 25 basis points. In 2025, the rate was 3.64% at the start of the year then decreased to 3.16% in July and decreased again to 2.91% in October.

12. Bank indebtedness

Through a mirror banking agreement with its parent Corporation, the Corporation has available to its use a $15,000,000 revolving line of credit bearing interest at Canadian commercial bank prime less 0.40%. The Corporation provides a guarantee on this facility, as outlined in note 25. The amount drawn on the facility totals $9,180,236 at December 31, 2025 (2024 - $9,782,751).

13. Accounts payable and accrued liabilities

	2025	2024
Trade payables	$ 15,648,318	$ 11,672,432
Payroll payables	467,432	393,575
	$ 16,115,750	$ 12,066,007

All payables and government remittances owing are current as at year end.

14. Long-term debt

	2025	2024
Term loans (a)	$ 32,354,192	$ 18,444,869
Financing loans (b)	678,231	806,547
Shareholder notes (c)	8,038,524	8,038,524
Shareholder demand notes (d)	5,057,845	5,057,845
Finance lease obligations (e)	1,745,186	370,784
	47,873,978	32,718,569
Less: current portion	465,799	353,475
	$ 47,408,179	$ 32,365,094

(a) Term loans

The Corporation has two term loan facilities which are part of a non-revolving credit facility, due November 2029 with interest payable monthly at daily CORRA plus 1.08%.

The first term loan of $10,000,000 (2024 - $10,000,000) is fully drawn on. On this term loan the Corporation has an interest rate swap agreement on a notional principal of $10,000,000 maturing November 25, 2029. The swap is held with the Bank of Nova Scotia and is a receive variable, pay fixed swap from November 25, 2024 to November 25, 2029. The interest rate swap agreement is in a net unfavourable position of $199,137 (2024 - $234,469) as at December 31, 2025. This agreement has effectively converted variable interest rates on the unsecured daily CORRA's to an effective fixed interest rate of 3.21% from November 25, 2024 to November 25, 2029, plus stamping fee of 1.08% for an all-in rate of 4.29% as disclosed in note 23. On maturity, the debt will return to the floating rate defined in the term loan.

The second term loan of $35,000,000 is drawn in the amount of $22,354,192 (2024 - $8,444,869)non-revolving credit facility, due November 2029 with interest payable monthly at daily CORRA plus 1.08%. The Corporation has entered into two interest rate swap agreements covering the term loan.

The first swap has a notional principal of $8,444,869 maturing November 25, 2029. The swap is held with the Bank of Nova Scotia and is a receive variable, pay fixed swap from November 25, 2024 to November 25, 2029. The interest rate swap agreement is in a net unfavourable position of $168,168 (2024 - $198,006) as at December 31, 2025. This agreement has effectively converted variable interest rates on the unsecured daily CORRA's to an effective fixed interest rate of 3.21% from November 25, 2024 to November 25, 2029, plus stamping fee of 1.08% for an all-in rate of 4.29% as disclosed in note 23. On maturity, the debt will return to the floating rate defined in the term loan.

The second swap, entered into during the year, has a notional principal of $10,000,000 maturing October 1, 2030. The swap is held with the Bank of Nova Scotia and is a receive variable, pay fixed swap from October 1, 2025 to October 1, 2030. The interest rate swap agreement is in a net unfavourable position of $212,752 (2024 - nil) as at December 31, 2025. This agreement has effectively converted variable interest rates on the unsecured daily CORRA's to an effective fixed interest rate of 3.21% from October 1, 2025 to October 1, 2030, plus stamping fee of 1.08% for an all-in rate of 4.29% as disclosed in note 23. On maturity, the debt will return to the floating rate defined in the term loan.

The associated unrealized gains and losses on the above swaps are included in the statement of operations in note 23.

Security on the loan is described in note 8.

14. Long-term debt (continued)

(b) Financing loans

The Corporation has seven vehicles under loan. The vehicle loans bear interest from 0.13% - 5.98%, with monthly principal payments of $886 to $8,722, maturing from February 2027 to November 2030. All loans are secured by the vehicles under their respective loans.

(c) Shareholder notes

The shareholder notes represent amounts owing to the municipal shareholders of ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principal outstanding. As the debt holder has not demanded repayment at December 31, 2025, the debt has been classified as long-term as the Corporation has eighteen months to repay the note when called. The principal amounts are convertible at the option of the Corporation into Class B shares. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The amounts owing to the municipalities are as follows:

	2025	2024
Aylmer	$ 1,694,863	$ 1,694,863
Central Elgin	806,436	806,436
East-Zorra-Tavistock	569,073	569,073
Ingersoll	3,402,080	3,402,080
Norwich	763,755	763,755
South-West Oxford	192,062	192,062
Zorra	610,255	610,255
	$ 8,038,524	$ 8,038,524

(d) Shareholder demand notes

The Corporation has a demand promissory note payable to the Town of Goderich for $2,974,454 (2024 - $2,974,454) which bears interest at 7.25%. Interest is payable in quarterly installments of $53,912. This note is unsecured with no fixed repayment terms associated with the principal outstanding. As the debt holder has not demanded repayment at December 31, 2025, the debt has been classified as long-term as the Corporation has eighteen months to repay the note when called.

The Corporation has a demand promissory note payable to the Municipality of West Perth for $1,183,391 (2024 - $1,183,391) which bears interest at 7.25%. Interest is payable in quarterly installments of $21,449. This note is unsecured with no fixed repayment terms associated with the principal outstanding. As the debt holder has not demanded repayment at December 31, 2025, the debt has been classified as long-term as the Corporation has eighteen months to repay the note when called.

The Corporation has a demand promissory note payable to the Municipality of West Perth for $900,000 (2024 - $900,000) which bears interest at 7.25%. Interest is payable in quarterly installments of $16,313. This note is unsecured with no fixed repayment terms associated with the principal outstanding. As the debt holder has not demanded repayment at December 31, 2025, the debt has been classified as long-term as the Corporation has thirteen months to repay the note when called.

14. Long-term debt (continued)

(e) Finance lease obligations

The Corporation has one capital lease which bears interest at 3.65%, with monthly principal payments of $8,314 maturing in December 2028.

The following table sets out a maturity analysis of lease payables, showing the undiscounted lease payments to be made after the reporting date.

	2025	2024
2025	$ -	$ 99,763
2026	277,915	99,763
2027	281,440	99,763
2028	285,035	99,763
2029	187,044	-
Thereafter	992,853	-
Total undiscounted lease payable	2,024,287	399,052
Interest	279,101	28,268
Present value of minimum lease payments	$ 1,745,186	$ 370,784

The corresponding right of use asset for the finance lease obligations has been disclosed in note 8.

(f) Reconciliation of movements of liabilities to cash flows arising from financing activities

	Notes and loans	Finance leases	Total
Balance at Jan. 1, 2025	$ 32,347,785	$ 370,784	$ 32,718,569
Proceeds from loans	14,054,874	-	14,054,874
Repayment of loans	(273,867)	-	(273,867)
Proceeds from finance leases	-	1,574,054	1,574,054
Payments of finance leases	-	(199,652)	(199,652)
Interest paid	(2,854,974)	(69,145)	(2,924,119)
	43,273,818	1,676,041	44,949,859
Capitalised borrowing	616,743	-	616,743
Interest expense	2,238,231	69,145	2,307,376
Balance at Dec. 31, 2025	$ 46,128,792	$ 1,745,186	$ 47,873,978
Balance at Jan. 1, 2024	$ 29,028,134	$ 2,709,825	$ 31,737,959
Proceeds from loans	18,942,350	-	18,942,350
Repayment of loans	(15,622,700)	-	(15,622,700)
Payments of finance leases	-	(2,339,041)	(2,339,041)
Interest paid	(3,019,126)	(96,370)	(3,115,496)
	29,328,658	274,414	29,603,072
Capitalised borrowing	273,386	-	273,386
Interest expense	2,745,741	96,370	2,842,111
Balance at Dec. 31, 2024	$ 32,347,785	$ 370,784	$ 32,718,569

15. Customer deposits

Customer deposits represent cash deposits from electricity distribution customers as well as construction deposits. These customer deposits bear interest at the OEB's prescribed interest rate, which is the Bank of Canada's prime business rate less 2%.

Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service. Due to the demand nature of these deposits, they are classified as current liabilities.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to deferred revenue.

Customer deposits comprised of:

	2025	2024
Electricity deposits	$ 607,133	$ 617,522
Construction deposits	1,833,869	901,044
	2,441,002	1,518,566
Less: Current portion	1,373,383	1,400,835
	$ 1,067,619	$ 117,731

16. Deferred revenue

Deferred revenue relates to the capital contributions received from customers and others. The amount of deferred revenue received from customers is $16,693,370 (2024 - $16,110,915). Deferred revenue is recognized as revenue on a straight-line basis over the life of asset for which the contribution was received. Amortization commences when the asset is available for use. During 2025, deferred revenue of $295,192 (2024 - $256,084) was recognized in income.

17. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2025, the Corporation made employer contributions of $464,672 to OMERS (2024 - $433,051). The Corporation expects to contribute a similar amount to the OMERS plan in 2026.

As at December 31, 2025, OMERS had approximately 665,000 members, of whom 45 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2025, which reported that the plan was 99% funded, with an unfunded liability of $1.3 billion. This unfunded liability is likely to result in future payments by participating employers and members.

17. Post-employment benefits (continued)

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expenses and remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation

	2025	2024
Defined benefit obligation, beginning of year	$ 1,112,800	$ 1,139,900
Included in profit or loss		
Current service cost	21,800	20,600
Interest cost	48,900	50,600
	70,700	71,200
Included in OCI		
Actuarial gains (losses) arising from:		
Changes in experience	83,600	(22,300)
Changes in financial assumptions	(38,300)	5,400
	45,300	(16,900)
Benefits paid	(109,700)	(81,400)
Defined benefit obligation, end of year	$ 1,119,100	$ 1,112,800

(b) Post-employment benefits other than pension (continued)

Actuarial assumptions

	2025	2024
Discount rate	4.80%	4.60%
Medical costs	5.14%	4.93%
Dental costs	5.58%	5.36%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $117,000 similarly, a 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $117,000.

18. Share capital

Authorized
Unlimited number of common shares

	2025	2024
Issued capital		
10,000 Common shares	$ 14,265,677	$ 14,265,677

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

No dividends were declared or paid in 2025 and 2024.

19. Revenue from Contracts with Customers

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. In the following table, revenue from contracts with customers is disaggregated by type of customer.

Sale of Energy

	2025	2024
Residential	$ 21,722,365	$ 20,792,240
Commercial	21,345,958	14,429,220
Large users	11,158,178	10,007,268
Other	23,415,094	26,548,411
	$ 77,641,595	$ 71,777,139

Distribution Revenue

	2025	2024
Residential	$ 10,196,207	$ 9,692,593
Commercial	3,952,649	3,869,250
Large users	1,420,078	1,280,547
Other	794,390	672,617
	$ 16,363,324	$ 15,515,007

20. Other revenue

	2025	2024
Service	$ 627,346	$ 546,404
Amortization of deferred revenue	295,192	256,084
	$ 922,538	$ 802,488

21. Employee salaries and benefits

	2025	2024
Salaries, wages and benefits	$ 2,880,338	$ 2,544,866
CPP and EI remittances	227,906	214,830
Contributions to OMERS	464,672	433,051
Post-employment benefit plans	70,700	71,200
	$ 3,643,616	$ 3,263,947

22. Operating expenses

	2025	2024
Contracting and consulting	$ 581,307	$ 794,679
Materials and supplies	1,417,499	1,265,297
Vehicle recovery	(409,778)	(341,054)
Billing and collecting	1,272,746	1,278,129
Office administration	2,631,964	2,086,352
Community relations	269,168	270,720
Gain on sale of assets	(51,761)	(361,483)
Other	192,901	156,831
	$ 5,904,046	$ 5,149,471

23. Finance costs

	2025	2024
Finance costs		
Interest expense on long-term debt	$ 555,327	$ 736,988
Shareholder note interest	949,487	949,487
Interest expense on customer deposits	85,355	32,006
Interest expense on finance leases	69,145	96,370
Overdraft and other bank charges	415,125	562,778
Total finance costs	2,074,439	2,377,629
Unrealized loss on interest rate swap	147,582	432,475
Net finance costs and unrealized swap loss recognized in profit or loss	$ 2,222,021	$ 2,810,104

24. Contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2025, no assessments have been made.

25. Guarantee

The Corporation has guaranteed the operating and term loans of its parent Corporation ERTH Corporation up to 25% of the Corporation's equity or $10,260,735. The loans are secured by a General Security Agreement covering all assets of the Corporation and a pledge of the shares of the Corporation. As the Corporation does not expect to be in a position where it would need to honour this guarantee, no liability has been recorded in these financial statements.

26. Operating leases

The Corporation is committed to lease agreements for low value or short-term leased equipment.

The future minimum non-cancelable annual lease payments for these low value or short-term leases are as follows:

	2025	2024
Less than one year	$ 1,190	$ 7,140
Between one and five years	-	1,190
	$ 1,190	$ 8,330

During the year ended December 31, 2025 an expense of $7,140 (2024 - $7,140) was recognized in operating expenses in the statement of comprehensive income in respect of operating leases.

27. Related party transactions

The transactions between the Corporation and its related parties, other than electricity delivery charges as noted below, are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless otherwise noted.

(a) Shareholders and ultimate controlling party

The sole shareholder of the Corporation is ERTH Corporation, which in turn is wholly-owned by nine municipalities consisting of Aylmer, Central Elgin, East-Zorra-Tavistock, Goderich, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth.

(b) Companies under common control

ERTH Corporation owns 100% of the issued and outstanding shares of ERTH Limited.

ERTH Business Technologies Inc. and ERTH (Holdings) Inc. are wholly-owned subsidiaries of ERTH Limited.

(c) Outstanding balances with related parties

The following represent due from/to in the normal course of operations:

	2025	2024
Due from:		
ERTH Corporation	$ 183,260	$ 131,907
ERTH (Holdings) Inc.	98,704	92,040
ERTH Business Technologies Inc.	1,137	782
	$ 283,101	$ 224,729

	2025	2024
Due to:		
ERTH Corporation	$ 282,265	$ 295,461
ERTH (Holdings) Inc.	344,288	414,972
ERTH Business Technologies Inc.	6,990	200
Town of Goderich	848,952	876,589
Town of Aylmer	571,525	481,113
	$ 2,054,020	$ 2,068,335

The Corporation has contracted ERTH (Holdings) Inc. and ERTH Business Technologies Inc., to provide maintenance and upgrades to the existing capital infrastructure of the Corporation and administrative services.

(d) Transactions with parent

The Corporation has a contract with ERTH Corporation, the parent company, for management services and rental of facilities used by the Corporation.

During the year, the Corporation paid management services, consulting services and lease fees for right-of-use assets to its parent in the amount of $1,382,000, $274,500 and $428,000 respectively (2024 - $1,150,000, $213,500 and $246,000).

27. Related party transactions (continued)

(e) Transactions with companies under common control

During the year, the Corporation had the following transactions with related parties as follows:

- purchased administrative services of $10,503 (2024 - nil) from ERTH Business Technologies Inc.
- purchased distribution system items of $423,3615 (2024 - $509,865), operations, maintenance and administration services of $1,583,365 (2024 - $1,368,397), sold capital items of $40,000 (2024 - $40,000), operations, maintenance and admission services of $169,767 (2024 - $201,981) to ERTH (Holdings) Inc.

In the ordinary course of business, the Corporation delivers electricity to ERTH (Holdings) Inc. Electricity is billed to ERTH (Holdings) Inc. at prices and under terms approved by the OEB.

(f) Transactions with ultimate parents

The Corporation delivers electricity to the nine municipalities throughout the year for the electricity needs of the municipalities and their related organizations. Electricity delivery charges are at prices under terms approved by the OEB. The Corporation also provided additional supports to its shareholders for various services and capital work in the amount of $75,693 (2024 - $268,611).

The Town of Goderich charges the Corporation for annual rent.

28. Financial instruments and risk management

Fair value disclosure

The carrying values of accounts receivable, unbilled revenue, due from/to related parties, bank indebtedness and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The fair values and interest rates used to calculate fair values are as follows:

	December 31, 2025			December 31, 2024		
	Carrying Value	Fair value	Interest rate	Carrying Value	Fair value	Interest rate
Term loan	$ 32,354,192	$ 33,706,435	3.65%	$ 18,444,869	$ 19,258,178	4.05%
Shareholder notes	13,096,369	13,954,711	3.66%	13,096,369	13,935,599	4.16%
	$ 45,450,561	$ 47,661,146		$ 31,541,238	$ 33,193,777	

The fair value of available for sale financial assets is based on the closing value of the equity in publicly traded markets.

Interest rate swaps are recorded at their fair value, which is provided at the measurement date by a third party Canadian commercial bank.

28. Financial instruments and risk management (continued)

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the municipalities of Aylmer, Central Elgin, East-Zorra Tavistock, Goderich, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth. As a result, the Corporation did not earn a significant amount of revenue from any one individual customer.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2025 is $719,112 (2024 - $592,257). An impairment loss of $118,769 (2024 - $112,946) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. The Corporation has estimated the expected credit losses using its historical loss rates and recent trends for customer collections along with current and forecasted economic conditions and data. Due to current uncertain economic conditions, the estimates and judgments made by management in the preparation of the expected credit losses allowance are subject to estimation uncertainty. The Corporation determines the expected credit loss allowance based on current estimates and assumptions, including but not limited to, recent trends for customer collections and current forecasted economic conditions. The Corporation continues to actively monitor its exposure to credit risk. At December 31, 2025, approximately $180,188 (2024 - $210,968) is considered 60 days past due. The Corporation has over 25,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits and service disconnections from customers in accordance with directions provided by the OEB. As at December 31, 2025, the Corporation holds security deposits in the amount of $607,133 (2024 - $617,522).

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

28. Financial instruments and risk management (continued)

(c) Liquidity risk

The Corporation's ultimate parent company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The ultimate parent's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $78.8 million credit facility, which is held by the parent and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2025, $49.7 million has been drawn under the parent's credit facility.

The Corporation also has a bilateral facility for $2.9 million for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $2,828,800 has been drawn and posted with the IESO (2024 - $2,828,800).

The following are the remaining contractual maturities of the financial liabilities at the reporting date. The amounts are gross and undiscounted, and include contractual interest payments.

	Carrying amount	Due within one year	Due within two to five years	Due more than five years
December 31, 2025				
Term loans	$ 32,354,192	$ 1,602,416	$ 36,677,618	$ -
Shareholder notes	8,038,524	602,889	8,339,969	-
Shareholder demand notes	5,057,845	379,338	5,247,514	-
Financing loans	678,231	275,182	458,685	-
Finance lease obligations	1,745,186	281,440	749,994	992,853
Bank indebtedness	9,333,496	9,333,496	-	-
Trade payables and accrued liabilities	16,115,750	16,115,750	-	-
Due to related parties	2,054,020	2,054,020	-	-
Customer deposits	2,441,002	1,373,383	1,067,619	-
	$ 77,818,246	$ 32,017,914	$ 52,541,399	$ 992,853

	Carrying amount	Due within one year	Due within two to five years	Due more than five years
December 31, 2024				
Term loans	$ 18,444,869	$ 813,419	$ 21,630,759	$ -
Shareholder notes	8,038,524	602,889	8,339,969	-
Shareholder demand notes	5,057,845	379,338	5,247,514	-
Financing loans	806,547	301,308	587,023	-
Finance lease obligations	370,784	99,763	299,289	-
Bank indebtedness	9,852,811	9,852,811	-	-
Trade payables and accrued liabilities	12,066,007	12,066,007	-	-
Due to related parties	2,068,335	2,068,335	-	-
Customer deposits	1,518,566	1,400,835	117,731	-
	$ 54,637,387	$ 27,584,705	$ 36,222,285	$ -

28. Financial instruments and risk management (continued)

Financial risks (continued)

(d) Capital disclosures

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2025, shareholder's equity amounts to $41,042,938 (2024 - $38,993,031) and long-term debt amounts to $47,408,179 (2024- $32,365,094).

Exhibit Staff-8(b)

CIBC Waiver

CIBC COMMERCIAL BANKING

Public Sector and Not-for-Profit Group
255 Queens Ave., Suite 2100
London, ON N6A 5R8

Tel: 519-661-8310

December 31, 2025

DELIVERED ELECTRONICALLY

Westario Power Inc.
24 Eastridge Road, RR #2
Walkerton, ON N0G 2V0

Re: Credit Agreement - Waiver of Covenant Breach

Hello,

Reference is made to the credit agreement dated July 20, 2020 (collectively, together with all amendments and as may further be amended, restated, supplemented, replaced or otherwise modified from time to time, the "Credit Agreement") between Westario Power Inc. the ("Borrower") and Canadian Imperial Bank of Commerce ("CIBC"). All capitalized terms used in this letter which are not otherwise defined shall have the meanings established for such terms in the Credit Agreement.

As of the date of this letter, the Borrower has breached the Debt Service Ratio (the "Covenant Breach") set out in the Credit Agreement by reporting the following:

(a) A Debt Service Ratio of 1.00 to 1.00 for the period ending December 31, 2025 which is lower than 1.25 to 1.00

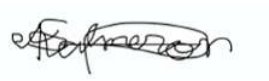
CIBC waives the respective Covenant Breach for the period ending December 31, 2025; provided that the breach was the result of withdrawals/distributions funded by surplus cash on hand.

The waiver by CIBC of the Covenant Breach does not in any way limit or restrict any other rights CIBC may have in respect of the Borrower's non-compliance with the terms of the Credit Agreement and does not constitute a waiver of any other rights, powers or remedies available to CIBC in connection with any future non-compliance, including the right to demand repayment of any and all amounts owing under the Credit Agreement (including, for greater certainty, the amended and restated credit agreement that will be entered into) at any time. The Credit

Agreement remains in full force and effect and CIBC requires full performance and full compliance going forward by the Borrower with all of its obligations and covenants under the Credit Agreement and the Security Documents.

Yours truly,

CANADIAN IMPERIAL BANK OF COMMERCE





Kevin Padilla
Authorized Signatory

Mark Wareing
Authorized Signatory