RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-49

Ref 1: Exhibit 9, pp. 12-13
Ref 2: OEB's Handbook to Electricity Distributor and Transmitter Consolidations, revised July 11, 2024
Ref 3: EPI_2026_Commodity_Accounts_Analysis_Workform_1.0_20250828 Excel

Preamble:
In reference 1, Entegrus Powerlines states that it seeks to harmonize its rate zones into a single tariff sheet, so that all Entegrus Powerlines' customers will be subject to a single Schedule of Rate and Charges. As part of this harmonization, and consistent with the methodology approved in its 2016 cost of service, Entegrus Powerlines also seeks to dispose of all Group 1 and Group 2 deferral variances on a harmonized basis, effective May 1, 2026.

As of March 1, 2025, Entegrus Powerlines consolidated into a single monthly settlement with the IESO. Accordingly, Group 1 DVAs are no longer maintained separately at the rate zone level. Entegrus Powerlines provides the Commodity Accounts Analysis Workform in reference 3 on a consolidated level.

Accordingly, effective January 1, 2025, Entegrus Powerlines proposes that future dispositions of all DVA accounts be accounted for and completed on a consolidated basis.
In reference 2, the OEB states:

> 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. Legacy balances should be tracked separately on a rate zone basis for

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purposes of maintaining cost causality at the time of disposition. However, if there are unique impacts to the utilities' Group 1 accounts, these circumstances should also be brought forward at the time of the consolidation application.

Question(s):

(a) Please provide the reference and narrative in the 2016 cost of service application, which sets out the methodology to present and consolidate the balances of Entegrus Powerlines' Group 1 and Group 2 DVAs.

1. Please explain how the proposed methodology in this application is consistent with the approved methodology in the 2016 cost of service application.

(b) Please provide Entegrus Powerlines' Group 1 DVA balances for its Main rate zone as of December 31, 2024.

1. Please provide Entegrus Powerlines' Group 1 DVA balances for its St. Thomas rate zone.

(c) Please provide the Commodity Accounts Analysis workform for the Main and St. Thomas rate zones, separately.

(d) Please provide a comparison of the Group 1 DVA balances and proposed rate riders by legacy rate zone, showing the impact on each customer class by rate zone if Group 1 DVAs were disposed of on a standalone basis (i.e. without harmonization) with Entegrus Powerlines' proposal as a consolidated balance.

(e) Please provide and discuss any cross subsidization as a result of disposing the Group 1 DVAs as of December 31, 2024 on a consolidated basis.

RESPONSE:

(a) In its 2016 Cost of Service (EB-2015-0061), Exhibit 9, Section 9.3 pages 11 – 12, EPI detailed the methodology to present and consolidate the balances of its Group 1 and Group 2 DVAs. The excerpt from that application is as follows:

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"As noted in Section 9.1 above, EPI currently maintains four rate zones. In this Application, EPI seeks to harmonize these four rate zones into a single tariff sheet, so that all EPI customers will be subject to a single Schedule of Rate and Charges. As part of this harmonization, EPI also seeks to dispose of all Group One and Group Two deferral variances on a harmonized basis, effective May 1, 2016. EPI believes the harmonized go forward DVA disposition is the best approach for the following reasons:

- *As of January 1, 2014, EPI consolidated into a single monthly settlement with the IESO. Accordingly, in order to maintain separate DVA's at rate zone level, allocations are currently required by rate zone based on annual bill determinant volumes; A single, harmonized disposition allows for a much less complex tariff sheet and facilitates the customer energy literacy and ease of understanding, which have been identified as a preference during EPI's customer engagement activities;*
- *Harmonization reduces administrative time spent on the DVA process; and,*
- *Harmonization creates more rate stability and less volumetric volatility for the smaller rate zones, since DVAs can now be spread over 40,000 customers, rather than rate zones of approximately 200 customers (i.e. Newbury)1 and approximately 600 customers (i.e. Dutton).*

Accordingly, effective January 1, 2015, EPI proposes that future dispositions of all DVA accounts be accounted for and completed on a consolidated basis. This methodology would ensure consistency among the dispositions proposed in this Application and future balances."

The proposal for rate harmonization explained above was approved in the OEB Decision accepting the EB-2015-0061 Settlement Agreement. As detailed in Exhibit 9, Section 9.3, pages 12-13 of this 2026 Cost of Service Application, EPI provides four reasons, consistent with those in EB-2015-0061, to support its proposal for disposing of all Group 1 and Group 2 DVAs on a consolidated basis.

(b) A breakdown of the DVA balances in Exhibit 9, Table 9-1 are provided by rate zone in the table below.

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Line No.	USoA	Description	Main Rate Zone	St. Thomas Rate Zone	Total
1	**GROUP 1**				
2	1550	Low Voltage	$ 1,134,055	$ -	$ 1,134,055
3	1551	Smart Metering Entity Charge	$ (127,350)	$ (57,041)	$ (184,391)
4	1580	RSVA Wholesale Market	$ (1,395,543)	$ (354,530)	$ (1,750,074)
5	1580	Variance WMS – Sub-account CBR Class B	$ 512,731	$ 103,163	$ 615,894
6	1584	RSVA Network	$ 1,765,942	$ 252,646	$ 2,018,588
7	1586	RSVA Connection	$ 1,168,999	$ 154,546	$ 1,323,545
8	1588	RSVA Power	$ 698,130	$ (269,677)	$ 428,452
9	1589	RSVA Global Adjustment	$ 928,781	$ 116,562	$ 1,045,343
10	1595	Disposition and Recovery of Regulatory Assets (2020)	$ 101,601	$ 0	$ 101,601
11	1595	Disposition and Recovery of Regulatory Assets (2021)	$ (17,670)	$ 16,698	$ (971)
12	1595	Disposition and Recovery of Regulatory Assets (2022)	$ 22,707	$ (8,460)	$ 14,247
13	1595	Disposition and Recovery of Regulatory Assets (2023)	$ (5,046)	$ 8,880	$ 3,834
14	1595	Disposition and Recovery of Regulatory Assets (2024)	$ 1,984,544	$ 11,535	$ 1,996,079
15		**TOTAL**	**$ 6,771,881**	**$ (25,678)**	**$ 6,746,202**

Please note that the table above includes balances that have already been disposed of in 2025 (2023 DVA Balance Disposition). For a breakdown of the balances being requested for disposition in this Application please see the table below. EPI has added two additional columns to the table originally filed in Exhibit 9, Table 9-4 to show the balance for disposition by rate zone.

Line No.	USoA	Description	Balance at Dec 31/24	2025 Disposition	Adjustments	Interest to Apr30/26	Balance for Disposition	Balance for Disposition - Entegrus Main Rate Zone	Balance for Disposition - Entegrus STT Rate Zone
	GROUP 1								
1	1550	Low Voltage	$ 1,134,055	$ 695,216	$ -	$ 17,455	$ 456,295	$ 456,295	$ -
2	1551	Smart Metering Entity Charge	$ (184,391)	$ (129,377)	$ -	$ (2,155)	$ (57,169)	$ (39,158)	$ (18,011)
3	1580	RSVA Wholesale Market	$ (1,750,074)	$ (1,409,114)	$ -	$ (16,637)	$ (357,596)	$ (323,046)	$ (34,550)
4	1580	Variance WMS – Sub-account CBR Class B	$ 615,894	$ 170,208	$ -	$ 18,521	$ 464,208	$ 402,113	$ 62,094
5	1584	RSVA Network	$ 2,018,588	$ 1,209,894	$ -	$ 31,663	$ 840,356	$ 636,097	$ 204,259
6	1586	RSVA Connection	$ 1,323,545	$ 1,004,973	$ -	$ 12,793	$ 331,365	$ 335,772	$ (4,407)
7	1588	RSVA Power	$ 428,452	$ 221,547	$ -	$ 8,101	$ 215,007	$ 350,165	$ (135,159)
8	1589	RSVA Global Adjustment	$ 1,045,343	$ 838,706	$ -	$ 9,134	$ 215,771	$ 226,041	$ (10,270)
9	1595	Disposition and Recovery of Regulatory Assets	$ (17,670)	$ -	$ -	$ (686)	$ (18,356)	$ (18,356)	$ -
10		**Subtotal**	**$ 4,613,743**	**$ 2,602,052**	**$ -**	**$ 78,190**	**$ 2,089,881**	**$ 2,025,925**	**$ 63,956**

(c) Please see the following attachments filed as live excel models:
EPI_IRR_1-Staff-49_2026_Commodity_Accounts_Analysis_Workform_MAIN_20251126
EPI_IRR_1-Staff-49_2026_Commodity_Accounts_Analysis_Workform_STT_20251126

(d) Please see the following tables.

		Group 1 (excl GA) Balance			Group 1 (excl GA) - Non-WMP Balance			1580, sub-account CBR Balance			Global Adjustment Balance		
		Harmonized	Main	St. Thomas	Harmonized	Main	St. Thomas	Harmonized	Main	St. Thomas	Harmonized	Main	St. Thomas
1	Residential	$ 486,827	$ 443,363	$ (2,065)	$ -	$ -	$ -	$ 256,036	$ 219,869	$ 35,015	$ 58,381	$ 45,254	$ (4,690)
2	General Service < 50 kW	$ 189,211	$ 175,376	$ 3,070	$ -	$ -	$ -	$ 92,547	$ 82,242	$ 11,651	$ 152,472	$ 173,702	$ (5,578)
3	General Service > 50 to 4999 kW	$ 653,085	$ 592,587	$ 71,824	$ (57,975)	$ 11,424	$ (60,893)	$ 95,739	$ 77,835	$ 14,682	$ -	$ -	$ -
4	Large Use	$ 130,403	$ 167,226	$ -	$ -	$ -	$ -	$ 5,798	$ 7,163	$ -	$ -	$ -	$ -
5	Unmetered Scattered Load	$ 1,450	$ 1,863	$ -	$ -	$ -	$ -	$ 691	$ 853	$ -	$ 4,377	$ 6,319	$ -
6	Sentinel Lighting	$ 386	$ 422	$ 5	$ -	$ -	$ -	$ 181	$ 191	$ 12	$ 541	$ 767	$ (2)
7	Street Lighting	$ 6,517	$ 5,510	$ 192	$ -	$ -	$ -	$ 3,099	$ 2,532	$ 471	$ -	$ -	$ -

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		Group 1 (excl GA) Rate Rider			Group 1 (excl GA) - Non-WMP Rate Rider			1580, sub-account CBR Rate Rider			Global Adjustment Rate Rider		
		Harmonized	Main	St. Thomas	Harmonized	Main	St. Thomas	Harmonized	Main	St. Thomas	Harmonized	Main	St. Thomas
1	Residential	$ 0.0011	$ 0.0014	$ (0.0000)	$ -	$ -	$ -	$ 0.0006	$ 0.0007	$ 0.0003	$ 0.0063	$ 0.0091	$ (0.0011)
2	General Service < 50 kW	$ 0.0012	$ 0.0015	$ 0.0001	$ -	$ -	$ -	$ 0.0006	$ 0.0007	$ 0.0003	$ 0.0063	$ 0.0091	$ (0.0011)
3	General Service > 50 to 4999 kW	$ 0.4851	$ 0.5599	$ 0.2495	$ (0.0435)	$ 0.0109	$ (0.2161)	$ 0.1894	$ 0.2236	$ 0.0932	$ -	$ -	$ -
4	Large Use	$ 0.5228	$ 0.6704	$ -	$ -	$ -	$ -	$ 0.2886	$ 0.3565	$ -	$ -	$ -	$ -
5	Unmetered Scattered Load	$ 0.0012	$ 0.0015	$ -	$ -	$ -	$ -	$ 0.0006	$ 0.0007	$ -	$ 0.0063	$ 0.0091	$ -
6	Sentinel Lighting	$ 0.4832	$ 0.6305	$ 0.0375	$ -	$ -	$ -	$ 0.2272	$ 0.2860	$ 0.0920	$ 0.0063	$ 0.0091	$ (0.0011)
7	Street Lighting	$ 0.4173	$ 0.5228	$ 0.0377	$ -	$ -	$ -	$ 0.1984	$ 0.2403	$ 0.0926	$ -	$ -	$ -

Line No.	Rate Class	Type	Typical kWh	Typical kW	2025 Final Rates by Rate Zone	2026 Proposed Rates Group 1 Rate Zone Disposition	$ Increase (Decrease)	% Increase (Decrease)	% Increase (Decrease) Harmonized Disposition[1]
1	**Entegrus - Main**								
2	Residential	RPP	750	-	$131.34	$136.02	$4.68	3.6%	3.3%
3	General Service < 50 kW	RPP	2,000	-	$326.91	$335.49	$8.58	2.6%	2.4%
4	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$29,594.54	$28,908.69	-$685.85	-2.3%	-2.6%
5	Large Use	Non-RPP	2,700,000	5,500	$441,816.86	$429,868.27	-$11,948.58	-2.7%	-3.0%
6	Unmetered Scattered Load	RPP	150	-	$30.37	$30.72	$0.35	1.2%	1.0%
7	Sentinel Lighting	RPP	150	1	$38.10	$38.24	$0.14	0.4%	-0.2%
8	Street Lighting	Non-RPP	345,000	2,300	$74,545.67	$77,899.94	$3,354.27	4.5%	4.0%
9	**Entegrus - St. Thomas**								
10	Residential	RPP	750	-	$130.70	$134.67	$3.96	3.0%	3.8%
11	General Service < 50 kW	RPP	2,000	-	$329.44	$331.89	$2.45	0.7%	1.6%
12	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$28,215.20	$28,531.38	$316.18	1.1%	2.1%
13	Sentinel Lighting	RPP	150	1	$39.38	$37.35	-$2.03	-5.2%	-3.5%
14	Street Lighting	Non-RPP	345,000	2,300	$72,783.65	$76,255.29	$3,471.64	4.8%	6.5%

Notes
1. Per Exhibit 1, Table 1-10.

(e) Referring to the table in part (a), with the exception of 1550, 1588, and the 1595 accounts not requested for disposition in this Application, all balances between rate zones are directionally similar. While total DVA balances are consistent, allocations are not, as allocations in the DVA continuity models are based on percentages (of customers, consumption, non-RPP consumption, etc.), which will be different on a non-harmonized basis.

In Exhibit 9 Section 9.3, EPI explains that disposing of Group 1 DVAs on a harmonized basis reflects its operation as a single, fully integrated utility since the 2018 merger. The proposed consolidation aligns with EPI's plan to implement a single tariff sheet in 2026, simplifies regulatory accounting and billing by eliminating separate rate zone riders, and ensures consistent treatment of all customers. Further, consolidation is consistent with the OEB's Handbook to Electricity Distributor and Transmitter Consolidations, dated January 19, 2016 that is applicable to the Entegrus/St. Thomas transaction.

A small degree of cross-subsidization is apparent in bill impacts, with a typical Main Residential customer seeing a bill increase 0.2% higher than in the harmonization scenario, and a typical St. Thomas Residential customer seeing a bill increase 0.8% lower than in the harmonization scenario.

For further details on low voltage harmonization specifically, please see the response at 8-Staff-47.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-50

Ref 1: Exhibit 9, pp. 12-13
Ref 2: OEB's Handbook to Electricity Distributor and Transmitter Consolidations, revised July 11, 2024, pp. 31-32

Preamble:
In reference 1, Entegrus Powerlines states that in this application, it seeks to harmonize [its rate zones] into a single tariff sheet, so that all Entegrus Powerlines' customers will be subject to a single Schedule of Rate and Charges. As part of this harmonization, and consistent with the methodology approved in its 2016 COS (EB-2015-0061), Entegrus Powerlines also seeks to dispose of all Group 1 and Group 2 deferral variances on a harmonized basis, effective May 1, 2026.
In reference 2, the OEB states:

> Legacy Group 2 accounts should also generally be tracked separately on a rate zone basis. Tracking accounts on a rate zone basis will enable those account balances to be disposed to the group of customers that contributed to the balances. However, there could also be some accounts where tracking on a rate zone basis may not be warranted post-MAADs transaction. Therefore, utilities shall be required to provide a proposal in their MAADs applications on which legacy or new Group 2 accounts are to be tracked to a legacy rate zone basis or consolidated basis going forward, with supporting rationale.

Question(s):
(a) Please provide Entegrus Powerlines' Group 2 DVA balances for its Main rate zone as of December 31, 2024.

1. Please provide the same for St. Thomas rate zone.

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(b) Please identify, for each Group 2 DVA included in this application, whether the account has been tracked during the deferred rebasing period on a legacy rate zone basis or a consolidated basis.

1. Please explain since what date Entegrus Powerlines started tracking each Group 2 DVA on a consolidated basis.
2. Please confirm whether Entegrus Powerlines informed the OEB of its decision on consolidating the Group 2 DVAs for its rate zones prior to this application. If so, please provide the reference and that information. i. If Entegrus Powerlines did not inform the OEB of its decision, please explain why.

(c) Please confirm whether Entegrus Powerlines is proposing, for each of its Group 2 DVAs, to dispose the balance on a legacy rate zone basis or a consolidated basis.

1. For any Group 2 DVAs Entegrus Powerlines' that were tracked on a rate zone basis but is now proposed to be disposed on a consolidated basis, explain why rate zone tracking is not warranted.

    i. Please calculate and describe the nature of any resulting cross-subsidy between the legacy Entegrus and legacy St. Thomas customer groups.
    ii. Please provide the reference from the MAADs evidence that describes Entegrus Powerlines' proposal regarding the Group 2 DVA tracking and future disposition.
    iii. Please explain how those balances are being allocated under harmonized riders to ensure that customers in each legacy rate zone bear the appropriate costs/benefits consistent with MAADs rate making principles.

2. If there are no Group 2 accounts that will remain tracked on a rate zone basis, please explain why this is the case.

(d) Please explain how the proposed harmonized DVA disposition interacts with any MAADs related earnings sharing mechanisms or deferred rebasing periods previously approved for the Main rate zone or the St. Thomas rate zone, if applicable.

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(e) Please provide the bill impacts for each rate class by comparing: 1. Entegrus Powerlines' proposed harmonized Group 2 disposition 2. Disposition on a rate zone basis 3. Please discuss the pros and cons of each approach in terms of cost causality and cross-subsidy, intergenerational equity and bill impacts.

RESPONSE:

(a) A breakdown of the Group 2 DVA balances at December 31, 2024 (excluding 2025 and 2026 interest) by rate zone is provided in the table below. EPI has divided the accounts between discrete balances specific to only one rate zone, and accounts which apply to both rate zones.

Line No.	USoA	Description	Main Rate Zone	St. Thomas Rate Zone	Total
1	**GROUP 2**				
2	Discrete Balances Between Two Rate Zones				
3	1508	Other Regulatory Assets - Deferred IFRS Transition Costs	$ -	$ 102,761	$ 102,761
4	1508	Other Regulatory Assets - OPEB	$ (303,036)	$ -	$ (303,036)
5	1518	RCVA Retail	$ 174,857	$ -	$ 174,857
6	1548	RCVA STR	$ 139,722	$ -	$ 139,722
7	1555	Smart Meter Capital and Recovery Offset	$ -	$ (9,205)	$ (9,205)
8	1576	CGAAP Accounting Changes	$ (95,665)	$ -	$ (95,665)
9	**Subtotal**		**$ (84,122)**	**$ 93,556**	**$ 9,434**
10	Balances Shared Between Two Rate Zones				
11	1508	Other Regulatory Assets - Pole Attachment Revenue Variance	$ (1,574,736)	$ (206,873)	$ (1,781,609)
12	1508	Other Regulatory Assets - OEB Cost Assessment	$ 838,506	$ 353,638	$ 1,192,144
13	1508	Other Regulatory Assets - Green Button Initiative	$ -	$ -	$ -
14	1508	Other Regulatory Assets - Designated Broadband Project Impacts	$ -	$ -	$ -
15	1508	Other Regulatory Assets - Getting Ontario Connected	$ 669,393	$ 205,550	$ 874,943
16	1508	Other Regulatory Assets - LEAP EFA	$ 357,291	$ 68,101	$ 425,392
17	1511	Incremental Cloud Computing Costs	$ 230,611	$ 70,813	$ 301,424
18	1592	PILs & Tax Variance - CCA	$ (1,851,875)	$ (793,661)	$ (2,645,536)
18	**Subtotal**		**$ (1,330,810)**	**$ (302,431)**	**$(1,633,242)**
19	**Total**		**$ (1,414,932)**	**$ (208,876)**	**$(1,623,808)**

(b) 1. All Group 2 DVAs included in this application have been tracked on a legacy rate zone basis during the deferred rebasing period, with the exception of 1508 Subaccount GOCA and Account 1511 Incremental Cloud Computing Costs. EPI continues to track the Group 2 DVAs on a legacy rate zone basis, excluding the two exceptions previously noted, which have been tracked on a consolidated basis since the respective accounting orders were issued in 2023. For purposes of splitting the balances between rate zones, EPI completed this in the table in part (a) by allocating these two accounts to rate zones based on kWh.

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2. As noted above, EPI has continued tracking the legacy Group 2 DVAs on a legacy rate-zone basis and is proposing consolidation in this Application.

(c) EPI is proposing to dispose of all Group 2 DVA balances on a consolidated basis. Per the table in part (a), the Group 2 DVA balances that are discretely rate zone specific total $(84,122) for Main and $93,556 for St. Thomas. EPI submits that this minimal amount of cross-subsidization is acceptable, given it is not material relative to EPI's materiality threshold of $195,577, nor is it material relative to the total Group 2 disposition of $(1,663,085). The remaining Group 2 balances, while tracked by rate zone, were derived by allocating consolidated balances to EPI's two rate zones. As such, their disposition would be materially similar whether disposed of on a consolidated or separate basis. Further, the proposed harmonized rate riders allocate costs and benefits in proportion to each customer class's current energy consumption and demand determinants ensuring that recovery aligns with cost causation under the merged entity's operations.

In its 2018 MAAD Application (EB-2017-0212), Section 7.4, pages 39-40, EPI states:

> EPI and STEI currently track certain costs to Group 1 and Group 2 deferral and variance accounts ("DVAs") approved by the Board. These DVAs are of a typical nature, with the possible exception of EPI's "Account 1508 Other Regulatory Assets, Subaccount – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account" as approved in the OEB's Decision on EPI's 2016 Cost of Service Application (EB-2015-0061).
>
> EPI requests leave to continue to track costs to the existing deferral and variance accounts currently approved by the OEB, as well as leave to continue to track costs in respect of the existing EPI rate zone to "Account 1508 Other Regulatory Assets, Subaccount – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account", pending finalization of the Board's EB-2015-0440 Consultation on the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs, following which the policy therein determined will be implemented.

(d) The proposed harmonized DVA disposition effective May 1, 2026, does not interact with the MAADs-related earnings sharing mechanism or deferred rebasing period approved in EB-

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2017-0212. The eight-year deferred rebasing period approved in that Decision ends April 30, 2026. During the deferred rebasing period, distribution rates for the Entegrus - Main and Entegrus - St. Thomas rate zones were adjusted under Price Cap IR. The approved ESM, applicable to years 6–8, operated independently of DVAs, and no balances related to the ESM have been recorded or proposed for disposition. Accordingly, the DVA disposition proposed in this proceeding has no overlap with the MAADs mechanisms.

(e) Bill impacts by rate class on a Group 2 rate zone disposition basis and on a harmonized basis are presented in the table below.

Rate Class	Type	Typical kWh	Typical kW	2025 Final Rates by Rate Zone	2026 Proposed Rates Group 2 Rate Zone Disposition	$ Increase (Decrease) Rate Zone Disposition	% Increase (Decrease) Rate Zone Disposition	$ Increase (Decrease) Harmonized Disposition[1]	% Increase (Decrease) Harmonized Disposition[1]	Difference
Entegrus - Main										
Residential	RPP	750	-	$131.34	$135.43	$4.09	3.1%	$4.38	3.3%	0.2%
General Service < 50 kW	RPP	2,000	-	$326.91	$334.09	$7.18	2.2%	$7.78	2.4%	0.2%
General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$29,594.54	$28,781.11	-$813.43	-2.7%	-$778.17	-2.6%	0.1%
Large Use	Non-RPP	2,700,000	5,500	$441,816.86	$428,149.20	-$13,667.65	-3.1%	-$13,287.92	-3.0%	0.1%
Unmetered Scattered Load	RPP	150	-	$30.37	$30.66	$0.29	1.0%	$0.29	1.0%	0.0%
Sentinel Lighting	RPP	150	1	$38.10	$38.14	$0.04	0.1%	-$0.10	-0.2%	-0.4%
Street Lighting	Non-RPP	345,000	2,300	$74,545.67	$83,053.49	$8,507.82	11.4%	$2,971.17	4.0%	-7.4%
Entegrus - St. Thomas										
Residential	RPP	750	-	$130.70	$136.47	$5.77	4.4%	$5.01	3.8%	-0.6%
General Service < 50 kW	RPP	2,000	-	$329.44	$336.49	$7.04	2.1%	$5.24	1.6%	-0.5%
General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$28,215.20	$28,914.85	$699.64	2.5%	$601.16	2.1%	-0.3%
Sentinel Lighting	RPP	150	1	$39.38	$37.57	-$1.81	-4.6%	-$1.37	-3.5%	1.1%
Street Lighting	Non-RPP	345,000	2,300	$72,783.65	$67,472.75	-$5,310.90	-7.3%	$4,733.19	6.5%	13.8%

In balancing cost causality, cross-subsidy, intergenerational equity, and bill impacts, EPI submits that harmonized disposition provides the optimal outcome in light of materiality. The difference in bill impacts for the vast majority of EPI's customers is *de minimis*, while the change in bill impacts amongst Street Lighting customers is significant. Under the unharmonized scenario, Main Street Lighting sees an 11.4% increase while St. Thomas Street Lighting sees an 7.3% decrease, despite being in the same harmonized rate class effective 2026.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-51

Ref 1: Exhibit 9, pp. 26-27
Ref 2: EB-2023-0143, Accounting Order for Getting Ontario Connected Act Variance Account, Schedule A

Preamble:
Entegrus Powerlines is requesting disposition of $910,487 as a collection from customers inclusive of interest to April 30, 2026. Table 9-20 in reference 1 provides the revenue requirement related to locate costs approved in base rates escalated by the annual IRM inflation rate less stretch factor, 2023-2024 actual locate costs, a forecast of locate costs for the 2025 calendar year, and the resulting balances recorded in the Account 1508 GOCA Variance Account. Entegrus Powerlines confirms it has reflected the GOCA impact in the locate costs of the 2026 Test Year's revenue requirement.

In reference 2, it states that utilities, in the rebasing application or IRM applications if applicable, are to demonstrate that recorded amounts in their accounts are both incremental to the base rates and are a direct result of Bill 93.

Question(s):
(a) Please discuss the methodology used to measure incremental costs and how Entegrus Powerlines assessed that the costs recorded in the GOCA Variance Account were directly related to Bill 93.

RESPONSE:

(a) Please refer to Exhibit 4, Sections 4.3.6 and 4.4.7 for a discussion of the incremental Supervisor of Locates and Locator positions that were added in direct response to Bill 93. In assessing the incremental costs, EPI identified and isolated all labour, vehicle, and associated overhead costs directly attributable to the additional resources required to comply

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with the legislation. Beginning in 2023, EPI also incurred incremental third-party locator costs above the level embedded in base rates, which arose from the need to complete locates within the legislated timeframes established under Bill 93.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-52

Ref 1: Exhibit 9, p. 29

In its application, Entegrus Powerlines states that in its 2016 cost of service proceeding, it established Account 1508 - Sub-Account - OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account. The purpose of this account is to record the difference in revenue requirement each year, effective May 1, 2016, between both the capitalized and OM&A components of OPEBs accounted for using a forecasted cash basis (as reflected in rates) and the capitalized and OM&A components of OPEBs accounted for using a forecasted accrual basis. Carrying charges do not apply to this deferral account. Entegrus Powerlines is requesting disposition of $303,036 as a refund to customers.

Question(s):
(a) Please provide a table by year showing the OPEB expense in rates on a cash basis, accrual basis, capitalized OPEB and OPEB in OM&A, and the resulting annual variance recorded in this account.

RESPONSE:

(a) The table below presents OPEB expenses on both a cash and accrual basis, the portions capitalized and included in OM&A, and the resulting variance recorded in the deferral account. It should be noted that Account 1508 – OPEB Deferral Account applies only to legacy EPI, as legacy STEI’s rates in EB-2014-0113 were not established using a forecasted cash basis. Accordingly, the balances presented below pertain solely to legacy EPI.

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Year	OPEB - Cash Basis	OPEB - Accrual Basis	Capitalized OPEB	OPEB in OM&A	Variance Recorded in 1508 OPEB Subaccount
	A	B	C	D = B - C	E = B - A
2016	$ 219,604	$ 196,212	$ 87,118	$ 109,094	$ (23,392)
2017	$ 219,981	$ 219,133	$ 99,925	$ 119,208	$ (848)
2018	$ 214,411	$ 211,208	$ 94,410	$ 116,798	$ (3,203)
2019	$ 226,833	$ 199,124	$ 88,212	$ 110,912	$ (27,709)
2020	$ 230,532	$ 232,554	$ 102,556	$ 129,998	$ 2,022
2021	$ 306,981	$ 183,315	$ 75,526	$ 107,789	$ (123,666)
2022	$ 287,698	$ 168,468	$ 70,757	$ 97,711	$ (119,230)
2023	$ 223,558	$ 228,035	$ 92,126	$ 135,909	$ 4,477
2024	$ 245,170	$ 233,683	$ 90,903	$ 142,780	$ (11,487)
Total					**$ (303,036)**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-53

Ref 1: Exhibit 9, pp. 27-31, including Table 9-25: Account 1511 Incremental Cloud-based Computing Implementation Costs
Ref 2: Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs

In 2024, Entegrus Powerlines launched a cloud-based Enterprise Resource Planning ("ERP") system to modernize its core business applications. This initiative replaced the existing financial system and introduced an integrated, cloud-based Human Resources Information System ("HRIS") and payroll module to support evolving operational and technological needs. The ERP and HRIS officially went live on November 1, 2024.

Entegrus Powerlines is requesting disposition of $313,628 as a collection from customers for Account 1511 - Cloud Computing Implementation Costs, inclusive of interest to April 30, 2026.

Entegrus Powerlines is considering the migration of its Customer Information System from an on-premise platform to a cloud-based solution prior to 2029. As such, it is seeking approval to maintain Account 1511 to capture any eligible costs that may arise during the 2026-2030 period.

Question(s):
(a) Please update the table in reference 1 by breakdown of the cloud solution(s), actual amounts, types of expenditure (e.g., capital or OM&A), and nature of costs (e.g., data migration, etc.).
(b) Please discuss the methodology used to measure incremental costs arising from the ERP/HRIS implementation and how this aligns with the Accounting Order in reference 2.
(c) Please provide a detailed breakdown of costs including hardware, software, labour, etc. associated with Entegrus Powerlines' old financial system, HR system and payroll module.
(d) Please confirm and identify any offsetting cost savings such as avoided on-premise hardware, reduced maintenance and explain whether they have been

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netted against the balance in Account 1511 or reflected elsewhere in the application.

1. If no offsetting savings have been identified, please explain why.

(e) If Account 1511 is to be closed and the forecasted cloud costs are to be embedded in this rebasing application, what would be the amounts (e.g. capital and OM&A) that would be included in rates?

(f) Please discuss why Entegrus Powerlines cannot reasonably forecast the potential migration to additional cloud solutions as part of its rebasing application, and is requesting to continue Account 1511.

RESPONSE:

(a) All costs presented in Exhibit 9, Table 9-25 reflect the actual expenditures incurred for the implementation of the integrated ERP/HRIS solution. The implementation was executed by a single third-party partner, and the nature of each cost item (e.g., software licensing, design, testing, etc.) is identified in the table. In the absence of the Accounting Order noted above in Reference 2, these implementation costs would have been expensed to OM&A under IFRS.

(b) All expenditures represent incremental costs associated with transitioning from legacy, on-premise systems to modern, cloud-based platforms. These amounts are incremental to the cost levels embedded in existing base rates, which were established to recover expenditures related to the prior on-premise financial, HR, and payroll systems. This aligns with the Accounting Order.

(c) Below is a summary of costs incurred for the legacy financial, HR, and payroll systems. These costs were capitalized and depreciated on a straight-line basis over a five-year useful life.

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Year	Nature of Expenditure	Amount
2011	Initial implementation	$ 562,158
2012	Minor upgrade	$ 9,563
2013	Minor upgrade	$ 27,840
2015	Major upgrade	$ 106,010
2016	Employee-self service module	$ 20,132
2016	EFT payment implementation	$ 10,060
2016	Time bank module	$ 6,630
2017	Fixed asset module	$ 79,744
2018	Minor upgrade	$ 6,795
2020	Minor upgrade	$ 18,720
2020	Major upgrade	$ 148,460
Total		**$ 996,113**

Ongoing annual maintenance costs were approximately $40k in 2016, increasing to $77k in 2024.

(d) No offsetting cost savings were identified in relation to the ERP/HRIS implementation. The transition to cloud-based solutions was primarily driven by the need to replace aging legacy systems and to enhance reliability, cybersecurity, and functionality. Accordingly, there were no avoided hardware or maintenance costs netted against the balance in Account 1511 or reflected elsewhere in the application.

(e) Forecasted cloud costs are uncertain at this time.

(f) At this time, EPI cannot reasonably forecast with sufficient certainty the potential future migration of its Customer Information System to a cloud-based platform. Such solutions are not yet widely available or commonly used in the industry. Therefore, EPI requests approval to maintain Account 1511 to record any eligible incremental costs that may arise during the 2026–2030 period.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-54

Ref 1: Exhibit 4, pp. 111-112
Ref 2: EB-2015-0061, Settlement Proposal, p. 12
Ref 3: Chapter 2 Filing Requirements for 2025 filers, Section 2.4.3.1

Preamble:
In reference 1, Entegrus Powerlines states that in its 2016 cost of service application, Entegrus Powerlines established Account 1508 - Sub-Account - OPEB Forecast Cash vs. Forecast Accrual Differential to capture the annual differences in revenue requirement, effective May 1, 2016, arising from using a forecasted cash basis (in rates) versus the…forecasted accrual basis for both capitalized and OM&A OPEB amounts.

Thereafter, following the OEB's September 14, 2017, OPEB guidance, accrual accounting became the default for rate-setting.

In reference 2, the approved Settlement Proposal states that Entegrus Powerlines agrees to adjust its 2016 Test Year capital expenditures to reflect the recovery of OPEBs on a cash basis, rather than an accrual basis, and the appropriate allocation of OPEBs between capital and OM&A subject to the approval of a new variance account…to record the difference in rates between these two methodologies pending the Board's final determination on the generic policy issue.

In reference 3, it states that the distributor must provide details of employee benefit programs, including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for in the last OEB-approved rebasing application, and for historical, bridge and test years. Further, if a distributor is proposing to change the basis in which pension and OPEB costs are included in OM&A from its last rebasing application (e.g., from cash to accrual), it must quantify the impact of the change.

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Question(s):

(a) Please confirm whether Entegrus Powerlines' is using the cash basis or the accrued basis of accounting for its pension and OPEB costs in the 2025 and 2026 test year revenue requirement.

(b) Please provide a breakdown of the pension and OPEBs amounts included in OM&A and capital for the historical, bridge and test years.

1. Please provide any allocation for affiliates.

(c) Please quantify the impact of moving from cash basis to accrual basis of accounting.

(d) Please confirm that in this application Entegrus Powerlines is proposing to fully dispose of the existing OPEB cash vs. accrual deferral account.

(e) Please confirm that Entegrus Powerlines is not proposing to use Account 1522 to track routine variance between forecast accrual OPEB costs included in rates and actual accrued OPEB costs.

RESPONSE:

(a) EPI applied the accrual basis of accounting for its OPEB costs in the 2025 bridge year and 2026 test year revenue requirement. As an OMERS employer, EPI follows the cash basis of accounting for its pension costs.

(b) The tables below present the OPEB and OMERS costs included in OM&A and capital for the historical, bridge, and test years, as well as the allocation for affiliates.

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Year	OPEB Costs	Capitalized OPEB	OPEB in OM&A	Allocation to Affiliates
2016	$ 245,386	$ 108,951	$ 136,435	$ 20,659
2017	$ 278,921	$ 127,188	$ 151,733	$ 24,643
2018	$ 259,646	$ 116,062	$ 143,584	$ 23,685
2019	$ 285,249	$ 126,365	$ 158,884	$ 25,308
2020	$ 301,722	$ 133,059	$ 168,663	$ 23,925
2021	$ 257,666	$ 106,158	$ 151,508	$ 20,471
2022	$ 237,265	$ 99,651	$ 137,614	$ 16,763
2023	$ 248,569	$ 100,422	$ 148,147	$ 15,675
2024	$ 252,905	$ 98,380	$ 154,525	$ 16,080
2025 Bridge	$ 265,550	$ 103,299	$ 162,251	$ 16,454
2026 Test	$ 278,828	$ 108,464	$ 170,364	$ 17,311

Year	OMERS Costs	Capitalized OMERS	OMERS in OM&A	Allocation to Affiliates
2016	$ 886,216	$ 393,480	$ 492,736	$ 74,610
2017	$ 950,257	$ 433,317	$ 516,940	$ 83,958
2018	$ 994,658	$ 444,612	$ 550,046	$ 90,734
2019	$ 976,534	$ 432,605	$ 543,929	$ 86,640
2020	$ 1,040,849	$ 459,014	$ 581,835	$ 82,533
2021	$ 982,574	$ 404,820	$ 577,754	$ 78,062
2022	$ 1,100,614	$ 462,258	$ 638,356	$ 77,762
2023	$ 1,106,773	$ 447,136	$ 659,637	$ 69,794
2024	$ 1,311,827	$ 510,301	$ 801,526	$ 83,406
2025 Bridge	$ 1,536,807	$ 597,818	$ 938,989	$ 95,221
2026 Test	$ 1,626,297	$ 632,630	$ 993,667	$ 100,968

(c) On average, from 2016-2024, the cash basis of accounting for OPEB costs has been approximately $34k higher per year than the accrual basis of accounting.

(d) Confirmed.

(e) Confirmed. In accordance with the OEB Report on Pension and OPEB (EB-2015-0040), EPI proposes to use Account 1522 to track the variance between the forecasted accrual-based OPEB costs included in rates and the actual cash payments.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-55

Ref 1: OEB's Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Electric Vehicle Charging Rate (EB-2023-0071)

Preamble:
On March 31, 2025, the Ontario Energy Board (OEB) released its final report and accompanying letter on the design of the Electric Vehicle Charging Rate (EVC Rate). The EVC Rate will reduce the Retail Transmission Service Rates (RTSRs) paid by participating EV charging stations and will better align the RTSRs that they pay with the transmission system costs incurred to serve them. The Accounting Order in reference 1 states that electricity distributors may record the incremental revenue requirement impacts directly attributable to the material costs of implementing the EVC Rate. The OEB expects these costs to be one-time implementation costs, as opposed to ongoing costs. As such, the OEB does not anticipate that distributors will require the deferral account beyond their next cost-based rate applications.

Question(s):
(a) Please confirm whether Entegrus Powerlines has incurred or expects to incur costs related to implementing the EVC rate.
(b) Please provide a breakdown of actuals or forecast of costs.

1. If Entegrus Powerlines has not incurred costs or cannot forecast costs at this time, please confirm when it will be able to.

(c) Please confirm whether Entegrus Powerlines intends to use the EVC generic accounts to record incremental revenue requirement impacts directly attributable to the material costs of implementing the EVC rate.

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1. If not, please confirm that Entegrus Powerlines will discontinue the account.

RESPONSE:

(a) – (c) EPI has not incurred any costs related to implementing the EVC rate and therefore has not used this account. EPI has not prepared a cost forecast as it expects future costs to be minimal. EPI will discontinue the account.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 9-STAFF-56

Ref 1: OEB's Final Rate Order for Extended Horizons Variance Account (EB-2024-0092)

Preamble:
The OEB established a variance account allowing rate-regulated electricity distributors to record the incremental revenue requirement impacts resulting from reductions in the forecasted customer capital contributions embedded in distribution rates. These reductions arise from the extensions of the connection horizon and revenue horizon for customer connections meeting the criteria described in the version of Appendix B of the Distribution System Code that came into force on December 23, 2024.

The OEB also expects that distributors will, as part of their next cost-based rate application, incorporate the impact of the expansions of the horizons into their forecast for the test year and beyond. As such, the OEB does not anticipate that distributors will require the Extended Horizons Variance Account beyond their next cost-based rate applications.

The generic variance account applies only to the forecasted connections that are currently embedded in distribution rates and eligible for the extension of connection and revenue horizons.

Question(s):
(a) Please confirm whether Entegrus Powerlines has assessed the impact of the extensions of the connection horizon and revenue horizon.

> 1. If not confirmed, please explain why. 2. If confirmed, please confirm that the impacts are embedded in the test year revenue requirement and provide the details.

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(b) Please confirm whether Entegrus Powerlines will discontinue the generic variance account. 1. If not, why not.

RESPONSE:

(a) Confirmed and confirmed. The annual impact on test year revenue requirement is an increase of approximately $20k for return on rate base, interest, and depreciation.

(b) Confirmed.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 9-SEC-41

[Exhibit 9, Table 9-1, p.12]

a. Please confirm that Entegrus has maintained separate Deferral and Variance Accounts ("DVA") for each rate zone since the merger.
b. If confirmed, please break out Table 9-1 into the two rate zones.
c. If not confirmed, when did Entegrus start recording DVA amounts on a consolidated basis?
d. Please calculate separate DVA rate riders for each rate zone based on the information in part b.
e. Please explain what Entegrus means with the statement "consistent with the methodology approved in EPI's 2016 COS (EB-2015-0061), EPI also seeks to dispose of all Group 1 and Group 2 deferral variances on a harmonized basis" stated on page 12.

RESPONSE:
Please see EPI's responses at 9-Staff-49 and 9-Staff-50.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 9-SEC-42

[Exhibit 9, Table 9-21]

Please provide evidence that the amount requested to be disposed of for account 1508 Other Regulatory Assets, Getting Ontario Connected Act ("GOCA") is directly a result of GOCA.

RESPONSE:

Please refer to the response at 9-Staff-51.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 9.0 -VECC -47

Reference: Exhibit 9, page 25

"This subaccount includes amounts paid for OEB Cost Assessments for the period April 1, 2016 to 10 December 31, 2024 in excess of amounts previously included in rates (2016 COS EB-2015-0061 for legacy EPI and 2015 COS EB-2015-0113 for STEI). The COS amounts have been escalated each year by the IRM inflation rate less stretch factor to calculate the annual variance. EPI has included a forecast to December 31, 2025 based on the expected 2025/26 OEB Cost Assessment per the OEB's Cost Assessment - Fiscal Year 2025-2026 letter dated June 30, 2025."

a) Please provide the detailed calculation showing the derivation of the assessment costs being sought for recovery.

b) Please provide the referenced OEB letter.

c) Did EPI seek or receive explicit approval of the OEB for the continuation of the OEB Assessment Cost Account at the time of its rate rebasing deferral (i.e. as part of its STEI MAADs application)?

RESPONSE:

a) Please see the table below.

Year	Amount in Rates	OEB Quarterly Assessments	Deferral Amount (Principal)	Deferral Amount (Interest)	Total DVA Amount
2016	$ 155,440	$ 234,295	$ 78,855	$ 321	$ 79,176
2017	$ 158,092	$ 263,046	$ 104,954	$ 1,469	$ 106,422
2018	$ 159,684	$ 245,857	$ 86,173	$ 3,521	$ 89,694
2019	$ 161,840	$ 249,363	$ 87,523	$ 8,142	$ 95,665
2020	$ 164,832	$ 248,124	$ 83,292	$ 5,361	$ 88,653
2021	$ 168,208	$ 241,016	$ 72,808	$ 2,726	$ 75,534
2022	$ 173,508	$ 266,628	$ 93,120	$ 10,990	$ 104,110
2023	$ 179,928	$ 299,502	$ 119,574	$ 29,099	$ 148,673
2024	$ 188,564	$ 346,301	$ 157,737	$ 46,058	$ 203,795
Total	**$ 1,510,096**	**$ 2,394,132**	**$ 884,036**	**$ 107,687**	**$ 991,723**
2025 Forecast			$ 200,423		$ 200,423
Prospective Interest January to December 2025				$ 37,858	$ 37,858
Prospective Interest January to April 2026				$ 11,639	$ 11,639
Total	**$ 1,510,096**	**$ 2,394,132**	**$ 1,084,459**	**$ 157,184**	**$ 1,241,643**

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b) The referenced OEB letter is provided as Attachment 1. EPI has also attached a letter received by the OEB on October 1, 2025 where the OEB directed the reactivation of Account 1508 – Other Regulatory Assets, Sub-account OEB Cost Assessment Variance effective April 1, 2025 (see Attachment 2).

c) EPI sought and received approval from the OEB in the EB-2017-0212 Decision and Order issued March 15, 2017, p.14, for the continuation of all existing deferral and variance accounts (which includes the OEB Cost Assessment Account).

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Attachment 1

9-VECC-47

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

June 30, 2025

To: Regulated Entities Subject to OEB Cost Assessment

Re: Cost Assessment - Fiscal Year 2025-2026

Under Section 26 of the *Ontario Energy Board Act, 1998*, capital and operating expenses of the Ontario Energy Board (OEB) are recovered from regulated entities through cost assessments. While awaiting approval of the OEB's 2025-2028 Business Plan from the Minister of Energy and Mines, the OEB issued Q1 and will be issuing Q2 invoices based on the approved FY2024/25 budget. If the Minister approves the FY2025/26 budget, **the OEB will increase invoices for Q3 and Q4.**

The OEB's 2025–2028 Business Plan outlines a strategic focus on delivering value to the people of Ontario through consumer protection and customer choice, regulatory policy leadership, innovation, and adjudicative excellence. In anticipation of increased expectations for the delivery of adjudicative and policy initiatives, the OEB has proposed a budget of $70.31 million for FY2025/26. This represents a $12.61 million increase over the approved FY2024/25 budget of $57.7 million.

Aligned with the Minister of Energy and Mines' Integrated Energy Plan Directive, assessment adjustments will reflect the incremental funding required to support enhanced operational capacity, accelerate key initiatives, and meet the growing demands of our regulatory and adjudicative responsibilities. Additional resources will also enable the OEB to scale up delivery in the latter half of this fiscal year, ensuring alignment with the strategic priorities outlined in the Business Plan to deliver a meaningful impact for Ontario energy consumers and stakeholders across the sector.

FY2025-2026 Assessment by Class of Payor

To allocate costs among payor classes, we rely on the OEB's Cost Assessment Model (CAM). The following table outlines the cost allocation by payor class for Q1 and Q2 of fiscal year

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4
T 416-481-1967 1-888-632-6273
F 416-440-7656 OEB.ca

2025-2026. Any necessary adjustments will be reflected during the Q3 and Q4 billing cycles, reconciling to the approved budget for FY2025/26.

Class of Payor	2025-2026 Q1 and Q2 Assessment	
	$*	% share of total cost
Electricity Distribution	7,828	56
Gas Utilities	3,489	25
Electricity Transmission	1,047	8
Independent Electricity System Operator	597	4
Ontario Power Generation	477	3
Unit Sub-Meter Providers	346	2
Retailers	144	1
Marketers	111	1
Total	14,040	100

(* in thousands)

Payment of Cost Assessment

Cost assessments are payable on a quarterly basis. The second quarter (Q2) covers the period from July 1, 2025, to September 30, 2025. Enclosed with this letter, you will find your cost assessment invoice along with electronic payment instructions for the Q2 payment to the OEB. Please note that electronic payment is due within 30 days of the invoice date.

Please direct any questions you may have relating to the attached invoice to accountsreceivable@oeb.ca

Sincerely,

Original signed by,

Walter Carvajalino

Manager, Finance & Risk | Ontario Energy Board

Attachments: Invoice dated June 30, 2025 & Electronic Payment Instructions

Attachment 2

9-VECC-47

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

October 1, 2025

To: Regulated Entities Subject to OEB Cost Assessment

Re: <u>Cost Assessment - Fiscal Year (FY) 2025/2026</u>

Under Section 26 of the *Ontario Energy Board Act, 1998*, the Ontario Energy Board's (OEB) capital and operating expenses are recovered from regulated entities through cost assessments. Cost allocation follows a Minister-approved budget for the fiscal year and updated information outlined in the OEB's Cost Assessment Model.

The government has entrusted the OEB with an ambitious work plan, articulated through the 2024 Letter of Direction and the government's 2025 Integrated Energy Plan Implementation Directive. This directive not only sets bold policy vision for Ontario's energy future but also signals a potential further expansion of the OEB's mandate.

The OEB's Business Plan lays out our blueprint to support Ontario's clean, affordable, and reliable energy sector and to support economic growth and energy security in the province. The Minister endorsed this approach through his approval of the OEB's 2025-2028 Business Plan on August 1, 2025.

Anticipating work arising from the government's first Integrated Energy Plan, the OEB developed a strategic and resource-aligned plan to deliver on the government's direction. This includes identifying and prioritizing roles that are **business-critical** and **sector-facing**—positions essential to adjudication, regulatory policy, stakeholder engagement and protecting the public. The approved FY2025/26 budget of $70.31 million reflects this purposeful investment.

While the approved FY2025/26 budget remains $70.31 million, the OEB is applying a forecast-based approach for Q3 assessments to reflect current operational realities. This approach seeks to ensure fairness to regulated entities while maintaining alignment with the OEB's strategic objectives. As part of our continued commitment to prudent financial management, the OEB will base Q3 invoices on its $63 million expenditure forecast for the year rather than the approved $70.31 million budget.

This adjustment reflects the current pause in hiring activity, following recent direction from the government. The OEB continues to seek clarity on how this process aligns with the energy sector transformation and our Business Plan. Until further guidance is received, mindful of impacts on both regulated entities and energy customers, the OEB is basing Q3 assessments on forecasted expenditures. The OEB will continue to monitor expenditures closely and will reassess the invoicing approach for Q4, making further adjustments if warranted. As previously communicated with our second quarter (Q2) invoices, the OEB issued first quarter (Q1) and Q2 cost assessments based on the approved FY2024/25 budget of $57.7 million.

FY2025-2026 Assessment by Class of Payor

Cost allocations among payor classes are determined using the OEB's Cost Assessment Model. The table below presents the cost distribution by payor class for Q3.

Adjustments for the final two quarters of the fiscal year will incorporate reconciliations for Q1 and Q2 billing cycles, ensuring alignment with the approved FY2025/26 budget.

Class of Payor	2025-2026 Q3 Assessment	
	$*	% share of total cost
Electricity Distribution	9,744	56
Gas Utilities	4,344	25
Electricity Transmission	1,303	8
Independent Electricity System Operator	727	4
Ontario Power Generation	594	3
Unit Sub-Meter Providers	432	2
Retailers	179	1
Marketers	138	1
Total	17,461	100

(* in thousands)

Payment of Cost Assessment

Cost assessments are payable on a quarterly basis. Q3 covers the period from October 1, 2025, to December 31, 2025.

Enclosed with this letter, you will find your cost assessment invoice along with electronic payment instructions for the Q3 payment to the OEB. Please note that electronic payment is due within 30 days of the invoice date.

Please direct any questions you may have relating to the attached invoice to accountsreceivable@oeb.ca.

Account 1508 Sub-account OEB Cost Assessment

The OEB is directing the reactivation of *Account 1508 – Other Regulatory Assets, Sub-account OEB Cost Assessment Variance*. This account was originally established through the OEB's letter dated February 9, 2016 (2016 Letter), to capture material differences between cost assessments embedded in rates and those arising from the cost assessment model implemented as of April 1, 2016.

Some utilities have ceased using this account in their cost-based applications following the guidance provided in the 2016 Letter. However, in light of the newly approved budget under the current cost assessment model, the OEB has determined that reactivating this account is necessary. This will ensure proper tracking and recording of material variances between the cost assessments embedded in rates and those resulting from the updated model.

Effective April 1, 2025, all applicable electricity distributors, natural gas distributors, Ontario Power Generation (OPG), and the Independent Electricity System Operator (IESO) are expected to re-establish and utilize *Account 1508 – Sub-account OEB Cost Assessment Variance*, or an equivalent account to record the cost assessment variances.

The accounting guidance for this account—including accounting entries, carrying charges, and disposition procedures—remains consistent with the instructions outlined in the 2016 Letter[1]. Regulated entities are expected to seek disposition of the account balances in their next cost-based application and generally request discontinuation of the account thereafter. If continuation of the account is requested, a clear rationale must be provided.

Please direct any questions you may have relating to the variance account to **IndustryRelations@oeb.ca** including "Account 1508 Sub-Account OEB Cost Assessment" in the subject line.

Sincerely,

Original signed by,

Walter Carvajalino

Manager, Finance & Risk | Ontario Energy Board

Attachments: Invoice dated October 1, 2025 & Electronic Payment Instructions

[1] The accounting guidance in Page 2 under the Section of New Variance Account in the OEB's letter Re "Revisions to the Ontario Energy Board Cost Assessment Model". issued to Regulated Entities Subject to the OEB's Cost Assessment, February 9, 2016.