RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-3

Residential power allocation standards
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 3.2.2
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.1.2
Ref. 3: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.3.3.5
Ref. 4: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.4.2
Ref. 5: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.2.2.3.1.3

Preamble:
Residential power allocation standards have been increased from 2 kVA in the northern part of Entegrus Powerlines' territory and 5 kVA in the southern part to 6 kVA with an option for 12 kVA, across the whole territory. Entegrus Powerlines attributes this change to "current homebuilding trends and system demands associated with DERs." This represents a material increase in unit capacity and potentially influence system renewal costs, loading assumptions, and customer connection charges.

Entegrus Powerlines has also updated the standard transformer for residential distribution to 100 kVA, with transformer bases designed to accommodate larger 166 kVA units.

In reference 5, Entegrus Powerlines notes that as adoption of EV's and heat pumps begins to ramp up, Entegrus Powerlines has identified risk to its distribution transformers becoming overloaded. Entegrus Powerlines has established a monitoring and forecasting program to identify individual assets most at risk.

Questions:
(a) Please describe how Entegrus Powerlines determined that 6 kVA and an optional 12 kVA were the appropriate residential capacity allocations (specifically and as opposed to any other allocation amount), and 100 kVA the appropriate transformer size?

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(b) Please comment on the merits and trade-offs of Entegrus Powerlines adopting a larger or a smaller capacity allocation and transformer size as its new standards.

(c) Please explain how and when Entegrus Powerlines expects to apply this new standard (for example, to new subdivisions only or also for all system renewal projects and upgrades for existing connections), and whether any material impact on capital spending is expected over the 2026-2030 DSP period.

(d) When does Entegrus Powerlines expect residential customer demand to reach and exceed 12 kVA?

(e) Please explain what is meant by "an option" for a 12 kVA allocation, including how such option may be exercised and any cost recovery and system implications.

(f) Does the current load forecast include impact of the upgraded power allocation standard of 6 kVA or 12 kVA? If not, please explain why Entegrus has chosen not to reconcile the two.

(g) Please provide details of the program mentioned in reference 5 and any results to date.

RESPONSE:

a) This strategy is fully aligned with broader policy context: the Federal government's decarbonization policy targets 100% zero-emission light-duty vehicle sales by 2035[1]. At the provincial level, the IESO forecasts that Ontario's electricity demand will grow by 75% by 2050[2]. Using the growth assumptions in these documents, additional public information (such as average number of vehicles per home, and average vehicle age), technical specifications for common L2 EV chargers, historical smart meter data and climate trend data EPI analyzed its loading data for residential customers and modelled future electrification load profiles incorporating the higher usage added by EV and electric heat pump adoptions. The analysis modelled 80th and 90th percentile residential loads beyond

[1] Transport Canada. (2025, October 6). *Canada's zero-emission vehicle sales targets*. Government of Canada. Retrieved November 24, 2025, from https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/canada-s-zero-emission-vehicle-sales-targets

[2] Independent Electricity System Operator. (2025). *Annual Planning Outlook*. Retrieved November 24, 2025, from https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

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2060. Results showed that winter will become the new system peak, and the average 80th percentile customer load may reach 12.5 KVA as early as 2043. Given this forecast, the incremental loads were not expected to finish materializing until mid-way through the life of a transformer installed today. Due to the uncertainty of forecasts over this time period, EPI adopted a staged approach. The initial deployment of 6.25 KVA per household aligns with current and near-term loading conditions, while 12.5 kVA serves as the long-term electrification demand load supported by the modelling. This modeling did not consider the impact of ULON rates, which may concentrate EV loads, accelerating the peak demand on distribution transformers. The following graph from EPI's study shows the 80th percentile customer loading profile with 73.5% electric vehicle penetration in residential households over the next two decades:

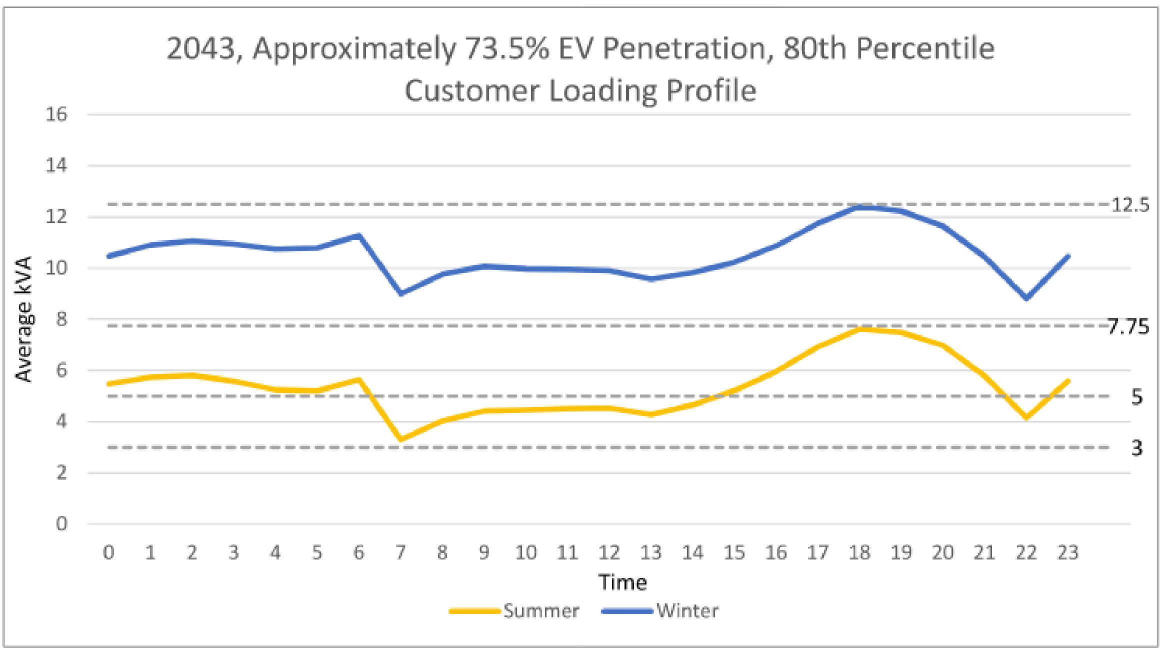

Fig 1: 80th Percentile Customer Loading Profile with 73.5% EV Penetration

Mapping the forecasted need onto commercially available transformers and optimizing the economic impact and other engineering needs, a 100 kVA standard unit was selected.

b) In selecting the 6.25 kVA standard, EPI sought to develop an optimal solution across several competing criteria. Selection of larger capacity allocation had the merit of helping to ensure that installed assets have a greater probability of reaching their target service life without

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issues of overloading triggering premature replacement. EPI's studies showed that mid-life replacement with up-sized assets resulted in extreme increases in lifecycle cost. This is countered by the fact that the timing of the ultimate load target is not expected to materialize for many years. Oversizing a transformer drives additional initial cost and line losses, without a matching benefit, leading to a less efficient capital program, and higher costs. Ultimately EPI's chosen design balances these competing needs and timing uncertainty by installing only capacity anticipated as being required in the medium term, while adopting a wiring configuration which allows the cost-effective addition on additional capacity, removing the need for mid-life asset replacement and its associated costs.

c) EPI began implementing the new design standard in 2024, primarily through ongoing voltage conversion projects and in new subdivisions, with additional reactive replacements where aging transformers fail or require renewal. EPI has determined that implementing the new design standard now has a modest incremental cost of $500 per lot, but is significantly less expensive over the full life cycle of the asset (i.e. it is more costly to remove an undepreciated asset mid-way through its useful life in order to upsize it).

d) Peak loading per household is currently anticipated to exceed 12 kVA by the year 2043.

e) The "option" of a 12 kVA capacity refers to added features in the design of the secondary bus of the distribution system. These features allow cost effective bus splitting on underground distribution (without these features, bus splitting on underground distribution can be very costly). As loads increase beyond what a single 100 kVA transformer can supply, a second unit can be installed, doubling capacity, with minimal incremental engineering, civil and labor cost. The option to install the additional capacity will be executed either at design time, if developer load forecasts require, or when ongoing monitoring identifies specific transformers experiencing chronic, damaging overload conditions. For new developments that require a larger capacity allocation per household (12.5 kVA, limiting 8 customers per 100 kVA instead of 16), the incremental cost of that higher capacity would be treated as a connection-specific capital increment and paid by the developer. For existing areas rebuilt through voltage conversions or asset replacements,

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costs would be funded through EPI's annual capital programs and recovered through the regulated rate base.

f) The load forecast includes all anticipated customer growth. It is important to note that the load forecast is based on energy in the near-term, while transformation capacity issues associated with this engineering change are concerned primarily with long-term local demand growth.

g) EPI has developed a transformer monitoring program to identify individual distribution transformers most impacted by overloading in conjunction with industry research. The program will analyze residential load servicing 25, 50, and 100 kVA single-phase transformers, and will flag transformers with an elevated risk of failure due to overloading. The program will be incorporated into EPI system planning processes to assist decision making, such as informing candidates for proactive transformer replacements, and will be developed further to analyze other transformer types and sizes. This program is further detailed in Exhibit 1, Section 1.9.1.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-4

Defective Equipment Related Outages

Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 3.3.1.3.2, Tables 3-25, 3-26, and 3-27

Ref. 2: Exhibit 2, Attachment 2-C DSP Part 4 of 6, Asset Condition Assessment Report 2024

Preamble:

Tables 3-25, 3-26, and 3-27 show that defective equipment continues to be a significant contributor to reliability events.

The 2024 ACA prepared by METSCO identifies health indices of several key asset classes.

Questions:

(a) Please summarize which asset classes contribute most to defective equipment outages and whether those same assets were identified in the 2024 ACA as being in "Poor" or "Very Poor" condition.

(b) Indicate whether Entegrus Powerlines expects the planed System Renewal programs to measurably reduce the frequency of defective equipment outages over the forecast period.

(c) Please explain why and how the approach Entegrus Powerlines is proposing in the 2026 DSP will succeed in improving equipment reliability, relative to the approach taken from 2021-2024.

(d) Briefly describe how Entegrus Powerlines monitors the effectiveness of system renewal investments - for example, by tracking reductions in defective equipment related outages.

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RESPONSE:

(a) As per the OEB's "Notice of Amendments to RRR 2.1.4.2 System Reliability" tracking of outages by sub-cause code did not come into effect until January 1, 2023. The data by asset class is therefore from January 1, 2023, to present. The top four asset classes that contributed the most to defective equipment outages during that timeframe were overhead switches, arrestors, overhead transformers, and underground transformers, respectively. 10% of EPI's overhead switches were identified as "Poor" or "Very Poor", arrestors were not included in the ACA, 11% of overhead transformers were identified as "Poor" or "Very Poor", and 2% of underground transformers were identified as "Poor" or "Very Poor".

(b) As described in Exhibit 2, DSP, Section 3.3.1.3.2, EPI expects long-term slow-moving changes and not immediately noticeable improvements.

(c) As described in Exhibit 2, DSP, Section 3.3.1.3.2, EPI does not expect to see an improvement, but rather a maintaining, of equipment reliability. As per Exhibit 2, Section 3.1.2.2, EPI plans to achieve this by completing proactive replacements of aged and degraded assets, as identified in the 2024 ACA, and continuing voltage conversion programs. The 2026 DSP is materially consistent with the approach of the 2021 DSP.

(d) As described in Exhibit 2, DSP, Section 3.3.1.3.2, Table 3-19, EPI monitors the direct effect of System Renewal investments on customer experience by tracking and monitoring the average number of hours that power to a customer is interrupted due to defective equipment and the average number of times that power to a customer is interrupted due to defective equipment on a yearly basis.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-5

Lost Time Hours
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 3.3.1.4.3

Preamble:

Entegrus Powerlines measures lost time hours by reviewing of statement of claim summaries provided by the Workplace Safety and Insurance Board (WSIB). Moving forward, Entegrus Powerlines intends to substitute lost time hours as the metric for employee health and safety with number of safety concerns submitted by employees; number of crew in-field visits conducted by senior leadership and board members; and IHSA COR audit score.

Questions:

(a) Does Entegrus Powerlines collect its own statistics on lost time hours?
(b) If it does, why does Entegrus Powerlines rely on WSIB claims to measure lost time hours?
(c) Please explain why Entegrus Powerlines is not supplementing its existing lost time hours metric with the aforementioned three new metrics, and is instead the dropping lost time hours metric altogether.
(d) Please describe the process by which Entegrus Powerlines employees submit safety concerns, and Entegrus Powerlines' process for responding to such submissions.
(e) Please explain how in-field visits by senior leadership and board members improve employee health and safety.
(f) Please explain how each of senior leadership and board members are trained to assess, report on, and/or correct workplace hazards during in-field visits.

RESPONSE:

(a) Yes.

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(b) Lost time incidents tracked by EPI inherently result in WSIB claims; accordingly, EPI's lost time figures align with those reported to the WSIB.

(c) EPI has shifted to leading indicator metrics that better support prevention and continuous improvement in safety performance. These include the number of employee-submitted safety concerns, the number of in-field visits by senior leadership and board members, and the IHSA COR audit score. Lost time continues to be tracked for WSIB compliance.

(d) EPI employees submit safety concerns through the BIS Safety portal, completing a form that details the concern, date, time and other relevant details. Submissions are routed to the Health & Safety Manager, who reviews and ensures timely resolution. All concerns are reviewed quarterly with the Joint Health & Safety Committee and the Board's Environmental Health & Safety Committee.

(e) In-field visits by senior leadership and board members demonstrate visible commitment to health and safety, reinforce compliance with established protocols, and strengthen the Internal Responsibility System by promoting shared accountability, employee engagement, and continuous improvement in safety performance across all levels of the organization.

(f) During in-field visits, senior leadership and board members are accompanied by the Manager of Health & Safety or operations management, who facilitate oversight and provide technical context on hazard identification and correction. Participation in EH&S meetings further supports awareness of workplace safety protocols. Responsibility for on-site hazard assessment and correction rests with the Manager of Health & Safety or operations management, who hold the required technical expertise.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-6

Voltage Conversion/Station Decommissioning Metric

Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.1.1.1
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 4 of 6, Asset Condition Assessment Report 2024, pp. 30-34
Ref. 3: Exhibit 2, Attachment 2-C DSP Part 6 of 6, Material Investments, Voltage Conversion, p. 113

Preamble:
The Station Decommissioning metric, newly introduced in this 2026-2030 DSP, provides a tangible performance measure of progress within the Voltage Conversion program. This metric demonstrates how capital investments are achieving both system efficiency and modernization goals, and how they align with broader asset management and strategic objectives, such as Grid Modernization and Cost Effectiveness. Although not specifically earmarked as a metric in the 2021-2025 DSP, Entegrus Powerlines was seeking to complete the decommissioning of 5 sub stations and reached this goal. For the 2026-2030 DSP window, Entegrus Powerlines will target the decommissioning of another 5 substations.

In reference 3, Entegrus Powerlines has stated that its fleet of distribution stations are nearing end-of-life, and the availability of parts for repair is dwindling.

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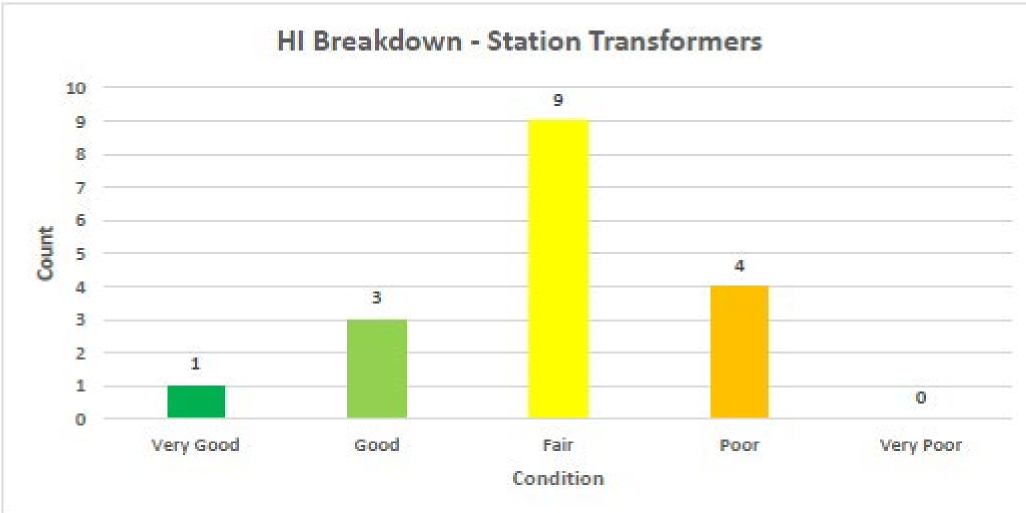

Table 4-3: Station Transformer HI Algorithm

Station	Asset	Age	MVA	Voltage	DAI	HI	Condition
STT Sub 15	SUB15	44	3	27.6/4.16 kV	83%	93%	Very Good
MP Sub 25 - Parkhill	MPSUB5	46	5	27.6/8.32/4.8 kV	99%	73%	Good
STT Sub 14	SUB14	44	3	27.6/4.16 kV	83%	72%	Good
STT Sub 9	SUB9	44	3	27.6/4.16 kV	83%	74%	Good
Blenheim East	BLET1	54	5	27.6/4.16/2.4 kV	100%	55%	Fair
Chatham Sub 1	SUB1T1	54	10	27.6/4.16/2.4 kV	100%	55%	Fair
Chatham Sub 1	SUB1T2	54	10	27.6/4.16/2.4 kV	100%	52%	Fair
Chatham Sub 4	SUB4T2	62	5	27.6/4.16/2.4 kV	100%	54%	Fair
Chatham Sub 6	SUB6T1	57	6	27.6/4.16/2.4 kV	100%	59%	Fair
MP Sub 23	MPSUB3	62	3	27.6/4.16/2.4 kV	99%	65%	Fair
MP Sub 24	MPSUB4	68	3.8	27.6/4.16/2.4 kV	95%	62%	Fair
Ridgetown Centennial	RICT1	57	3	27.6/4.16/2.4 kV	100%	54%	Fair
Wheatly DS	WHT1	69	2	27.6/4.16/2.4 kV	100%	54%	Fair
Chatham Sub 3	SUB3T1	57	7.5	27.6/4.16/2.4 kV	100%	48%	Poor
MP Sub 21	MPSUB1	47	5	27.6/4.16/2.4 kV	99%	47%	Poor
Ridgetown Tecumseh	RITT1	66	3	27.6/4.16/2.4 kV	100%	46%	Poor
STT Sub 11	SUB11	44	3	27.6/4.16 kV	83%	33%	Poor

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Questions:

(a) What does Entegrus Powerlines intend to achieve by creating Station Decommissioning as a separate metric?

(b) What analysis did Entegrus Powerlines consider in deciding the pacing of the station decommissioning plan? Did Entegrus powerlines conduct a system-wide benefit cost analysis? If yes, what benefits were considered in such analysis?

(c) Please elaborate on the what does Entegrus Powerlines mean by “distribution stations are nearing end-of-life” in reference 3, considering that distribution station comprises on several assets such as station building, power transformers, circuit breakers, switches, etc.

(d) Has Entegrus Powerlines performed risk analysis for each station for their entire stations fleet?

(e) Was Health Indices for stations equipment taken into consideration in coming with the voltage conversion plan?

(f) If service age was to be removed from asset condition assessment for power transformers, how would the Health Indices change for power transformers?

(g) As per reference 1, it appears that Entegrus Powerlines has decommissioned 5 substations between years 2021-2025 and is planning to decommission 5 more between yeas 2026-2030. Please complete the table below to show the station decommissioning plan for years 2026-2030 and years beyond 2030.

	2026	2027	2028	2029	2030	2031	…
Number of Stations Decommissioned as a Results of Voltage Conversion							Add more yeas as needed

(h) Please provide a reduced investment pacing plan that Entegrus Powerlines might have considered when assessing for appropriate pacing in the same table format as above. Please provide details on the risk associated with choosing the reduced investment pacing plan.

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RESPONSE:

(a) EPI has established Station Decommissioning as a dedicated metric to track progress under its voltage conversion strategy of retiring substations before major replacements become necessary. As noted in Exhibit 2, Attachment 2-C, Section 3.1, EPI serves 17 non-contiguous communities across Southwestern Ontario, supplied through multiple Hydro One transmission and distribution delivery points. The diverse development history of these communities produced numerous substations operating at legacy voltage levels (2.4 kV, 4.16 kV, and 8.32 kV). Many of these assets (some commissioned in the 1950s and 1960s) are increasingly difficult to maintain due to age, deterioration, and the scarcity of replacement parts (DSP, Section 4.2.2.2). By formalizing this measure, Entegrus reinforces its long-standing voltage conversion program, a consistent focus across the 2016, 2021 and 2026 DSPs. Under this program, associated line assets are rebuilt to contemporary 27.6 kV standards, after which the corresponding low-voltage substations are retired—enhancing reliability, capacity, and overall system resilience.

(b) EPI does not decommission stations as a priority on its own. Rather, EPI is focused on executing on its voltage conversion program and has introduced station decommissioning as one measure of progress for its voltage conversion program. It is important to differentiate between station offloading and decommissioning. As EPI's conversion work proceeds (See Exhibit 2, Distribution System Plan, Section 3.1.2.2), eventually all customers for a given station are transitioned to the contemporary 27.6 kV voltage, leaving the station unloaded. Once unloaded stations are no longer needed to support surrounding stations to maintain system reliability, they no longer deliver value. The ability to decommission a station is thus the culmination of a sustained effort, normally over several years. While decommissioning costs are themselves are fairly modest compared to offloading, decommissioning marks the end of the process and improves maintenance costs and system losses. As such EPI does not perform a BCA on station decommissioning and has not undertaken a study regarding its pacing.

(c) EPI's assessment is based on a synthesis of information from its ACA, which identifies station assets in poor condition, as well as practical engineering considerations that are not easily captured in a condition assessment. These include factors such as the ability to

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perform ongoing maintenance and repair due to obsolescence or the declining availability of spare parts, as well as qualified service providers with the necessary expertise. For example, an asset may appear to be in reasonable condition, but if a minor replacement part cannot be sourced or manufactured in a timely and cost-effective manner, the entire asset may become unusable. Please see the response at 2-Staff-7 (d) for a detailed example.

(d) EPI has performed a risk assessment on all stations. This assessment is primarily focused on customer-centric reliability, and evaluates how quickly, and by which means, power could be restored in the event of a contingency that renders a station inoperable. Contingency restoration plans have been developed for all stations.

(e) When developing conversion plans, all impacted assets have their HI considered in the prioritization. Line asset condition (poles, transformers, etc.) are considered as well as station assets. At the time of developing the capital plan (2024) assets in the areas targeted by the Voltage Conversion program had widespread serious degradation:

Asset Type and condition	Percentage
Poles (Fair or Worse)	93%
Poles (Poor or Very Poor)	22%
Transformers (Fair or Worse)	97%
Transformers (Poor or Very Poor)	79%

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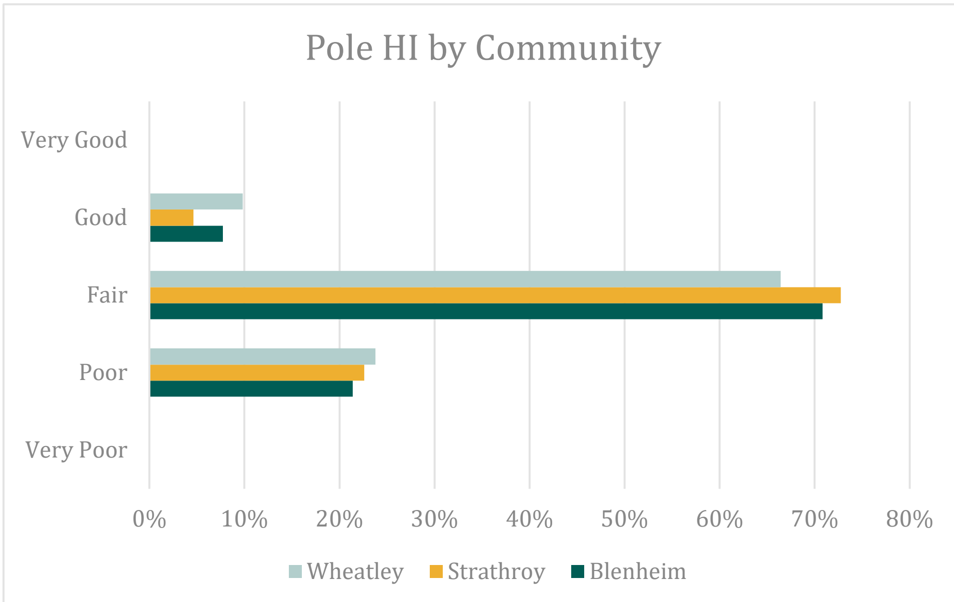

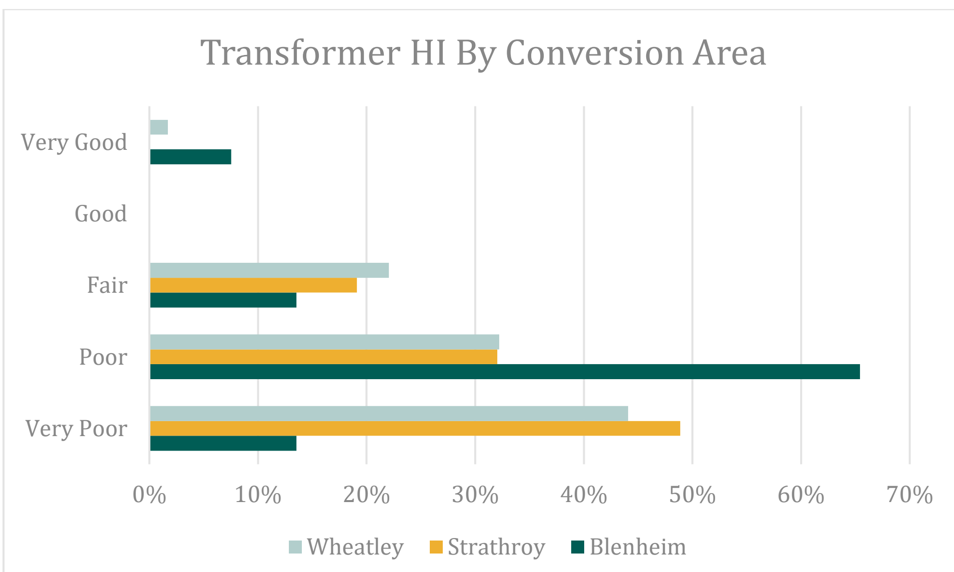

Station failures represent a specific, high-impact failure mode. As such, specific analysis is done to evaluate the EPI's ability to sustain the station, as well as the availability of alternative supply arrangements, with greater priority given to projects where either of these are more challenging.

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(f) EPI notes that use of age in health indices is a standard practice in the industry. Even in HI's like EPI's comprising many variables, age serves as an important predictor of failure – which is at once quantitative, objective, and highly correlated with equipment survival statistics, as is proven by a variety of industry reports. Age, among its other functions, serves as proxy for all internal components, the condition or which cannot be assessed without destructive testing. Removal of such a central indicator of asset health without replacement for the various factors it serves as proxy for compromises the analysis. As such, EPI does not believe the remaining criteria and their relative weightings represent a valid assessment. EPI's DSP consultant corroborates this assessment. See below for recalculated indices of the power transformers with "Age" removed as a condition parameter. :

Station	Asset	Recalculated index (Age Removed)	Offloaded or decommissioned as of 2025-11-01
STT Sub 15	SUB15	100%	Decommissioned
MP Sub 25 - Parkhill	MPSUB5	80%	
STT Sub 14	SUB14	76%	Decommissioned
STT Sub 9	SUB9	78%	
Blenheim East (BLE)	BLET1	59%	
Chatham Sub 1	SUB1T1	59%	Offloaded
Chatham Sub 1	SUB1T2	56%	Offloaded
Chatham Sub 4	SUB4T2	62%	Decommissioned
Chatham Sub 6	SUB6T1	64%	Offloaded
MP Sub 23	MPSUB3	74%	
MP Sub 24	MPSUB4	71%	
Ridgetown Centennial	RICT1	58%	

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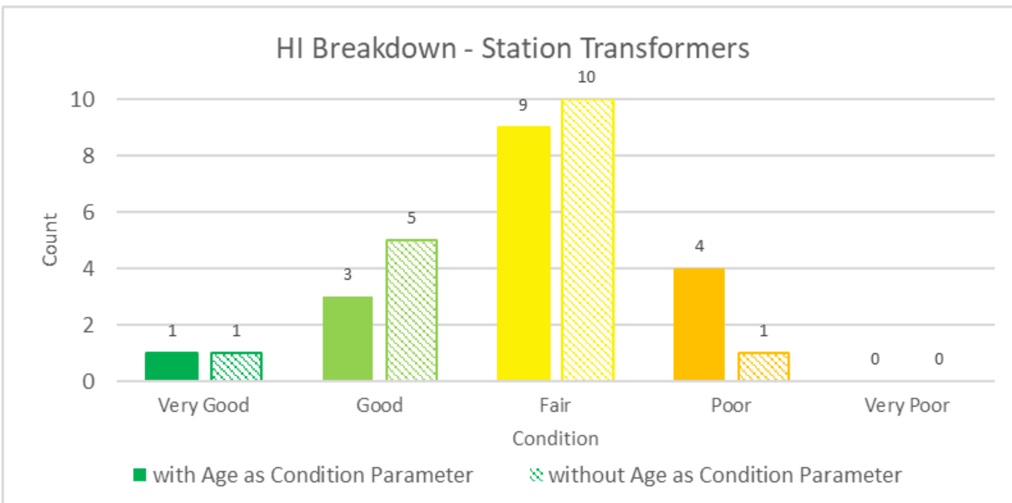
Wheatley DS	WHT1	62%	
Chatham Sub 3	SUB3T1	51%	
MP Sub 21	MPSUB1	50%	
Ridgetown Tecumseh	RITT1	52%	
STT Sub 11	SUB11	30%	



Note: 50% is the boundary between Fair and Poor.

(g) EPI intends to focus on decommissioning the following stations during the forecast period:

	2026	2027	2028	2029	2030	Years Beyond 2030
Station Decommissioned	3	0	1	0	1	Not relevant

Each of the 3 stations planned for decommissioning in 2026 have been offloaded in prior years and are no longer used or useful.

This question asks EPI for information outside the forecast period in the DSP, which is not in scope nor relevant to the matters at issue in this 2026 cost of service application.

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(h) Due to the manner in which pacing is developed (see (b), Exhibit 2, Distribution System Plan 4.3.1) EPI believes the current plan already represents a paced investment approach to achieve EPI's strategy of avoiding costly station rebuilds, provide the reliability benefits of smart-grid to its customers, and deliver DER capacity to its customers (note that 10 of the 11 restricted feeders are on EPI's 4kV network – Exhibit 2, Distribution System Plan, Section 4.5.3).

Reducing the pacing of decommissioning does not yield material cost savings for the reasons described in part (b) above and instead creates inefficiencies, increases O&M expenses, and limits opportunities to improve system losses.

Reducing the pace of station offloading so that offloading work for Wheatley DS is completed over 2029-2031 instead of 2029-2030, would result in re-allocating approximately $820k within the System Renewal category, from voltage conversion to pole replacements, transformer replacements, critical defect replacements, and other miscellaneous system renewal activities. EPI already considers line asset conditions into the selection of substations targeted for offloading; therefore, the current conversion plan is focused on addressing some of EPI's most deteriorated assets. Failure to maintain the asset replacement rates established in the plan would result in an overall worsening of EPI's asset condition, with corresponding negative impacts to system reliability and customer satisfaction. EPI does not recommend this reallocation for the reasons set out in the response at 2-VECC-12(d).

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-7

Asset Condition Assessment - Station Switches
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.2.2.2.3

Preamble:
Entegrus Powerlines monitors its station assets (including station switches) through monthly visual inspections, but Metsco's assessment relied on age as the only parameter for assigning a health index score to station switches. Based on age, all station switches were deemed to be in "very poor" condition.

Entegrus Powerlines notes that it maintains two portable backup stations that can be put into service in the event of asset failure.

Questions:
(a) Does Entegrus Powerlines disagree with Metsco's assessment of the health of its station switches?
(b) If so, please explain what Entegrus Powerlines views as the "true" health of its station switches.
(c) Is Entegrus Powerlines planning to update the asset condition assessment for station switches to include the condition data along with age?
(d) Please provide details of when, where, for how long, and under what circumstances the backup stations have been put into service.

RESPONSE:

(a) No. As discussed in Section 4.2.2.2.3 of the DSP, these assets are aged and remain in service, and are monitored through monthly inspections. Moving forward, EPI will enhance data collection to capture detailed inspection and condition information for station switches.

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(b) N/A.

(c) Yes, please see (a) above.

(d) The portable backup stations are typically deployed for approximately two weeks per year as part of the station maintenance program, when switching to alternate supplies cannot accommodate the load. In addition, the portable backup stations are available to be deployed as needed in emergency circumstances. For example, in 2025, EPI's Ridgetown Centennial DS was damaged by animal contact, destroying a transformer bushing. The station load was temporarily transferred to the Ridgetown Tecumseh DS. Due to the age of the station's transformer at the Ridgetown Centennial station, no spares were available either at EPI, or after a search of the secondary market. A replacement bushing and bus bar needed to be custom manufactured, resulting in the station remaining out of service for approximately 4 months. This incident occurred during summer peaking season, which further resulted in EPI deploying a portable backup station for approximately one week to relieve system peak demand while repairs were completed. In the absence of the portable backup station, the community would have experienced multiple extended outages.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-8

Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.3.1.1.1

Preamble:
Entegrus Powerlines’ practice in asset renewal is to maintain the status quo vis-à-vis underground or overhead assets.

Questions:
(a) Why is Entegrus Powerlines’ approach to maintain whichever asset configuration already exists?
(b) What assessments have Entegrus Powerlines made as to whether there is an overall preferred configuration (overhead or underground) in its territory?
(c) Has Entegrus Powerlines assessed the general costs of its approach whereby underground assets needing upgrades or replacement are replaced only by undergrounds assets, generally at a higher cost, and not considered for conversion to above-ground/overhead?
(d) Has Entegrus Powerlines considered reevaluating this practice given factors such as load growth due to electrification and extreme weather impacts?

RESPONSE:

(a) EPI currently does not have a policy to favour an overhead or underground configuration. When performing planned rebuild work, EPI performs case by case analysis to determine if the existing overhead/underground configuration is still optimal, adjusting as current and anticipated future local conditions require. Expansion work is performed in accordance with customer preference.

(b) EPI has not performed a system level analysis regarding a preference for overhead versus underground asset deployment. See part (a).

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(c) See part (a).

(d) EPI's system adaptations for electrification and climate change are in progress, with examples being the improvements to data availability in the ACA, as well as the updated construction standards to the 6.25/12.5kVA standard. EPI expects adoption of the recently published VASH framework in accordance to OEB policy will assist in making these determinations once it comes into effect.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-9

EV and Heat Pump Penetration
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.4.2
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.1.3.1.3

Preamble: Entegrus Powerlines states that its customer surveys show that customers have only modest interest in EVs. Entegrus Powerlines also states that it is seeing a steady penetration of EV chargers into its distribution network.

Questions:
(a) Please clarify what Entegrus Powerlines sees as customer interest in EVs (i.e., limited interest or steady growth).
(b) How does Entegrus Powerlines collect and catalogue data pertaining to EV charger and heat pump installations? How many EV chargers and heat pumps have been deployed in Entegrus Powerlines' service territory to date?
(c) Please provide the current and forecast annual growth rate for EV chargers and heat pumps in Entegrus Powerlines' service territory.

RESPONSE:

(a) EPI believes both statements to be concurrently true. Growth in registration data is present and consistent, but it is occurring more slowly than anticipated at the provincial level, indicating a limited interest from EPI's customers (See Exhibit 2, DSP, Section 3.2.1.2.1).

(b) EPI collects EV registration data from the ministry of transportation by Forward Sortation Area (FSA). While this does not map exactly to EPI's territorial boundaries, alignment is reasonable. EPI is also in the process of developing EV detection tools based on smart-meter data disaggregation. Based on Q2-2025 data, EPI has approximately 739 EVs registered in

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its service territory.

EPI does not currently have tracking of heat-pump deployments, although it is investigating opportunities to collect this data.

(c) EPI determines the current and forecast annual growth rate of EV chargers from forward sortation area (FSA) EV registration data, and historical growth rates. Between Q2 of 2022 and Q2 of 2025 an average of 45 EV's were registered per quarter within EPI's service territory. Continuation of these quarterly additions through 2026 would suggest an average of 975 EVs registered in EPI's service territory in 2026; equal to 1.68% of EPI's forecast residential customer count in 2026. Despite growth in EV sales over the 2022 to 2024 period near-term trends remain uncertain, with Ontario Zero-Emission Vehicle sales having decreased 18.62% from Q2 2024 to Q2 2025, and Battery Electric Vehicle sales decreasing 28.02% over this same time period.[1]

As noted in part (b) above, EPI currently does not have tracking of heat-pump deployments, as such the forecast growth rates of heat-pumps is indeterminable.

[1] Statistics Canada. Table 20-10-0025-01 New motor vehicle registrations, quarterly, by geographic level, Ontario, https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010002501

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-10

Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.7.1.1

Preamble:

While many of its peers outsource IT asset management to varying degrees, Entegrus Powerlines emphasizes the development of in-house expertise where it is both feasible in the short term and strategically beneficial in the long term.

Questions:

(a) Please elaborate further on the benefits and downsides of in-house versus outsourced IT expertise, including why the approach that Entegrus Powerlines claims has been adopted by many of its peers would not be beneficial or appropriate for Entegrus Powerlines.

(b) Has Entegrus Powerlines conducted a comparative cost analysis of in-house and outsourced IT asset management? If yes, please provide.

RESPONSE:

(a) EPI evaluates in-house and managed-service models for IT asset management on a case-by-case basis, weighing cost, security, reliability, ownership, and service quality. Maintaining in-house expertise ensures direct control over critical systems, supporting reliability, cybersecurity, and service continuity through staff with deep knowledge of interconnected systems such as SCADA, OMS, GIS, CIS, and financial platforms.

While managed services offer predictable pricing and specialized skills, they typically involve higher recurring costs, reduced transparency, and increased third-party risk, particularly regarding data privacy, cybersecurity, and response times. EPI's experience shows that once integration, compliance, and oversight costs are included, managed arrangements often provide less control and responsiveness.

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Given these factors (and regional limitations on rapid on-site support), EPI maintains a hybrid model: in-house management of core infrastructure, cybersecurity, and integration, complemented by external specialists for defined, high-complexity functions (e.g., penetration testing or major software upgrades). This approach preserves system ownership, cost discipline, and reliability while ensuring compliance and operational flexibility.

(b) Yes. EPI reviews managed-service opportunities on a case-by-case basis to assess cost-effectiveness, risk exposure, and operational alignment before pursuing any outsourcing arrangement. During system renewals, EPI periodically obtains quotes for fully managed service models covering functions such as network and systems administration, end-user support, application and database management, data protection and recovery, vulnerability and access management, lifecycle planning, and compliance oversight. In all cases, the quoted costs were materially higher than maintaining in-house capability and were predominantly based on remote delivery models, which were found to be less effective given EPI's operational structure and customer-service expectations.

Through these evaluations, EPI has consistently determined that fully managed models result in higher ongoing costs once integration, compliance, and vendor oversight are considered. Such arrangements also introduce additional third-party risk and typically reduce responsiveness and flexibility when addressing operational needs. Moreover, a minimum level of internal IT staffing is required under any model to maintain cybersecurity oversight, system governance, vendor coordination, and regulatory compliance. Consequently, outsourcing further functions would not reduce core staffing requirements but would instead layer additional vendor costs and management complexity.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-11

Substation Decommissioning
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.8.2

Preamble:
As Entegrus Powerlines proceeds with the decommissioning of its lower-voltage substations, the substation land will become available, and Entegrus Powerlines will evaluate the best course of action for each individual land parcel.

Questions:
(a) Who owns the land and in disposing of this land is there any benefits to rate payers. If not, why not?
(b) What is the current value of the land that will become available through the substation decommissioning initiative? Please provide this information for each substation.
(c) For each substation that has already been decommissioned, please describe what has been done with the land pertaining to the substation and how Entegrus Powerlines decided on a course of action for each of the decommissioned substations.
(d) Please describe the general options and considerations that Entegrus Powerlines has in determining the future of its decommissioned substation land, including if and how Entegrus Powerlines determines if substation land may be needed for future utility purposes.

RESPONSE:

(a) EPI owns the land. To the extent that a disposition occurs and a gain on sale is forecasted in the 2026 Test Year, ratepayers will benefit through the inclusion of that gain in the determination of the revenue requirement by way of Other Revenue. In addition, the disposition of land reduces EPI's rate base, which is also reflected in the calculation of the revenue requirement.

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(b) The table below outlines the current carrying value of land projected to become available during the 2026–2030 Forecast Period under the substation decommissioning program. EPI has not obtained appraisals for these properties; therefore, the current market value of the land is not known at this time.

Line No.	Station Name	Year of Decommissioning	Current Carrying Amount - Land
1	Chatham Sub 1	2026	$ 48,740
2	Chatham Sub 3	2026	$ 4,000
3	Chatham Sub 6	2026	$ 3,549
4	Strathroy Sub 24	2028	$ 10,425
5	Blenheim East	2030	$ 1,260

Please note that decommissioning costs of approximately $50k (and potentially higher depending on the extent of required remediation) will be added to the carrying value of each substation as the decommissioning program is implemented.

(c) EPI assesses the future use of decommissioned substation land on a case-by-case basis, considering both current and long-term system needs. Upon decommissioning, each property is evaluated to determine whether it may be required for future utility purposes, such as system expansion, contingency support, or the integration of emerging technologies. Key evaluation criteria include the site’s proximity to load centres, accessibility to existing distribution infrastructure, and potential to support future system reinforcement.

Where a property is determined to be no longer required for utility operations, EPI may explore alternative uses, including repurposing for operational storage, leasing to third parties, or disposition through sale.

Currently, EPI retains ownership of three decommissioned substation properties for which final disposition decisions have not yet been made. A $50k gain on sale of redundant assets has been included in Other Revenue in the Test Year to reflect potential gains from any such future dispositions. All other decommissioned substation lands have been sold.

(d) Please refer to the response in (c) above.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-12

Fleet
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.9.1
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 4.9.3
Ref. 3: Exhibit 2, Attachment 2-C DSP Part 6 of 6, Attachment J, 22. Rolling Stock section B.3.5, Table 2, pp. 192-193

Preamble:
To address vehicle utilization disparities across its two operating centres, Entegrus Powerlines considers and employs vehicle rotation with the aim of "levelling" mileage and wear across the fleet. Entegrus Powerlines' fleet asset management strategy determines suitability for replacement first based on age of the vehicle and then with secondary consideration to mileage.

Entegrus Powerlines' table of planned fleet replacement shows considerable variation in mileage between vehicles of similar age, for example vehicles no. H11BK08 and H13BK9102 and vehicles no. H16PU116 and H17PU175.

Questions:
(a) Please explain why Entegrus Powerlines has chosen a strategy of vehicle rotation between its two operating centres instead of servicing/replacing those vehicles that encounter more wear as they become worn.
(b) Please provide any assessment Entegrus Powerlines has done of the cost savings and/or operational efficiencies gained through the practice of rotating vehicles across its operational centres.
(c) Please explain why there is such considerable differences in mileage between vehicles of similar age and assigned to the same department that are planned to be replaced.
(d) Given this variation, please explain if Entegrus Powerlines has considered a more nuanced and/or precise asset management policy for its fleet, for example one that would use metrics beyond age

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and mileage to determine the actual need for replacement.

RESPONSE:

(a) EPI seeks to ensure that all vehicles are fully utilized before disposal. Rotation between operating centres allows EPI to level utilization across its fleet by taking advantage of differences in mileage accumulation rates between locations. The fleet is also experiencing the residual effects of merger integration. Historically, Legacy St. Thomas vehicles rarely operated outside the community boundaries, whereas legacy EPI vehicles traversed a 16-community service territory. This resulted in a disparity in average mileage by vehicle age across the combined fleet.

(b) EPI has not undertaken a formal study on savings.

(c) Please see part (a) above and Exhibit 2, Distribution System Plan, Section 4.9.

(d) Please see Exhibit 2, Distribution System Plan, Section 4.9.1 for EPI's discussion on when it considers life extension on fleet vehicles. EPI has already integrated a nuanced set of considerations into its asset management policy for its fleet when it considers the question of lifecycle extensions.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-13

Customer Connections Forecast
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.1.1.1, Table 5-6
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.1.2.1, Table 5-10
Ref. 3: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.1.3.1, Table 5-14
Ref. 4: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.1.4.1, able 5-18

Preamble:
Variances for commercial and industrial customer connections were high in 2021, 2022, 2023, and 2024.

Questions:
(a) Why was Entegrus Powerlines not aware of the various developments that led to these significant variances?
(b) What process improvements has Entegrus Powerlines made so that it is better aware of anticipated or impending growth in customer connection requests, particularly from commercial and industrial customers?

RESPONSE:

(a) The variances in commercial and industrial (C&I) customer connections between 2021 and 2024 were largely attributable to the timing and unpredictability of local economic development during, and immediately after, the pandemic period. Despite strong efforts at coordination with third parties, EPI is sometimes not made aware of such developments until a formal application for service is received. This lag arises because major C&I projects typically progress through municipal and private-sector planning stages before any electrical servicing requirements are disclosed. Conversely, some C&I developments initially announced in the region do not materialize or proceed later only after significant delays, which makes forecasting based on announcements unreliable.

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(b) Since the pandemic period, EPI has strengthened its processes to improve awareness of impending development and connection requests as described in Exhibit 2, Attachment 2-C, DSP Sections 3.2.2 and 3.2.3. Specifically, EPI has:

- Enhanced communication protocols between its engineering and operations staff and local municipal and regional economic development officers;
- Established routine participation in Technical Advisory Committees and planning meetings with municipalities and developer associations to obtain earlier visibility on proposed C&I expansions; and
- Updated its corporate website and digital communication channels to encourage developers and large customers to contact EPI early in their planning process.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-14

Customer Connections Forecast
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.2.1.1.2
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.2.1.4.1
Ref. 3: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 3.2.3
Ref. 4: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 3.2.1
Ref. 5: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 3.2.3

Preamble:
Entegrus Powerlines states that many commercial and industrial customer connection requests are unpredictable. Entegrus Powerlines also states that capital expansion requests from Entegrus Powerlines' municipal shareholders and other parties are variable and suggests that they are therefore difficult to predict.

Question:
(a) Given that business expansion generally requires careful planning, why does Entegrus Powerlines feel it experiences challenges in better forecasting commercial and industrial connection requests?
(b) Given that municipal and provincial governments often plan infrastructure projects years in advance, why does Entegrus Powerlines feel it experiences challenges in better forecasting requests from third parties such as governments to relocate Entegrus Powerlines assets?
(c) At what point in the planning process in Entegrus Powerlines notified (by a municipality, prospective customer, etc.) of a potential connection?
(d) Please describe the lessons Entegrus Powerlines has learned from its experiences in predicting customer connection and capital expansion requests, and how these lessons are applied to the forecasts underpinning its current forecasts.
(e) Please describe how Entegrus Powerlines has enhanced its customer consultation processes to

better refine its system access budgeting process.

RESPONSE:

(a) Please see the response at 2-Staff-13 (a).

(b) Although municipal and provincial governments develop multi-year infrastructure plans, EPI has found that the exact timing of requests for asset relocations can be difficult to predict in practice. As noted in 2-Staff-13(a), some developments, including municipal road or infrastructure projects, may be announced but remain contingent on favourable market, fiscal, or broader geopolitical conditions, and as a result, may be delayed or never materialize. These factors contribute to uncertainty in the timing and scope of relocation requests.

(c) Notification timing varies depending on the municipality and the nature of the project. In some communities, EPI is informed through Technical Advisory Committee (TAC) or Utility Coordination Committee (UCC) meetings early in the design phase; in others, notice is not received until detailed civil design or tendering is underway. For private developments, contact generally occurs only when an application for service is filed.

(d) EPI has learned that it must be even more proactive in engaging with municipal economic development offices, planners, and engineering departments as described in Exhibit 2, Attachment 2-C, DSP Section 3.2, to gain early insight into potential growth and infrastructure projects. This has informed the current forecast process, which places greater emphasis on direct outreach, recurring coordination meetings, and ongoing monitoring of regional development activity to refine the timing and probability of connection requests.

(e) EPI has enhanced its customer consultation and forecasting processes by expanding early-engagement channels. EPI's website has been updated to provide clearer guidance on connection requirements and to encourage developers and municipalities to contact EPI at the conceptual stage of their projects. EPI also participates in standing TAC and UCC meetings with municipal staff to facilitate coordinated planning of subdivisions, industrial expansions, and road works, improving the accuracy of its System Access budgeting and the efficiency of project delivery.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-15

Climate Change and Emergency Response
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.1.5.2

Preamble:
Entegrus Powerlines notes that its increased budget for emergency response is in response to greater than planned historical expenditures, which may be reflective of climate change.

Questions:

(a) Please list what other budget line items have been increased due to climate change risk, and how Entegrus Powerlines incorporates climate change risk into its capital plan and asset management policies overall.
(b) Has Entegrus Powerlines conducted a system-level risk assessment to identify assets that are vulnerable to climate change?
(c) Along with the emergency response budget, has Entegrus Powerlines included any planned investments in the 2026-2030 DSP?

RESPONSE:

(a) EPI acknowledges an increase in average wind speeds and severe weather over the historical period (Exhibit 2, Attachment 2-C, DSP Section 3.3.2.2 and Figure 11). While EPI does not currently maintain programs which explicitly address climate change risk, these considerations are embedded in EPI's broader asset renewal strategy. EPI's asset renewal investments represent a critical first step in enhancing system resilience, as this modernizes infrastructure and reduces vulnerability to more extreme operating conditions. Further, recent CSA standards updates have introduced more stringent design and construction requirements that inherently improve climate durability, and these are reflected in EPI's ongoing capital programs.

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(b) No. EPI looks forward to integrating the newly published VASH framework into its planning process to more explicitly address these risks.

(c) EPI assumes this question pertains to climate change investments. See part (a) above.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-16

Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.2.2.2

Preamble:
Entegrus Powerlines plans to begin testing poles on a community-by-community basis to reduce travel time for testers.

Question:

Has Entegrus Powerlines considered what other parts of its asset base or inspection programs could benefit from this testing and/or inspection methodology (e.g. overhead line inspections)? Please describe.

RESPONSE:
Yes. Where feasible and appropriate, EPI already applies a community-by-community approach to its inspection programs to maximize efficiency and reduce travel requirements. For visual pole, civil infrastructure, conductor, and cable inspections, EPI groups its assets into three geographically efficient areas and completes patrols on a three-year cycle. Vegetation management programs and infrared inspections are also organized using these same three areas and follow a cyclical schedule. Station inspections are also grouped by town to further improve efficiency and coordination of field activities.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-17

Metering Infrastructure Upgrade
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.2.2.4.1
Ref. 2: Exhibit 2, Attachment 2-C DSP Part 6 of 6, Attachment J, 9. Metering Renewal, Section A.5

Preamble:
Entegrus Powerlines has stated that in addition to upgrading meters, Entegrus Powerlines intends to upgrade the AMI communication infrastructure, including network servers, signal amplifiers, etc., and prepare for AMI 2.0

Questions:
(a) Please describe Entegrus Powerlines' plans and approach to AMI 2.0.
(b) Please explain how Entegrus Powerlines' preferred option for meter replacement (targeted like-for-like meter replacement with phased network consolidation) will adequately support Entegrus Powerlines' planned transition to AMI 2.0.
(c) Please describe in greater detail the incremental benefits of meter upgrades that would be "unlocked" if Entegrus Powerlines' overall AMI communication infrastructure were to be upgraded as well.
(d) Please provide number meters per year that are planned to replace in 2026 to 2030 period and beyond for the entire population in the format below.

	2026	2027	2028	2029	2030	2031	…
Number of meters planned to be replaced							Add more yeas as needed

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(e) Please provide a reduced investment pacing plan that Entegrus Powerlines might have considered when assessing for appropriate pacing in the same table format as above. Please provide details on the risk associated with choosing the reduced investment pacing plan.

RESPONSE:

(a) As an approved early adopter of smart meters, many of EPI's meters now surpassed their typical service lives. Sustainment investments are therefore planned during 2026–2030 to replace expiring meters and associated AMI core infrastructure such as gateways, servers, and communications assets. EPI's AMI 2.0 approach is a phased migration to a modern smart metering system, based on lifecycle replacement of the original smart meters.

(b) EPI's targeted like-for-like replacement with phased consolidation offers a prudent and technically sound pathway to AMI 2.0. The original smart meters are replaced with modern equivalents as they fail, become obsolete, or reach seal expiration, avoiding premature removal of still-functional assets. These replacements consider EPI's geographic layout, completing updates in individual communities, minimizing the amount of communications infrastructure required (areas where duplicate networks must be maintained), while ensuring dense deployments of the legacy system to maximize its performance. This staged approach minimizes capital outlay and customer disruption while maintaining full compliance with Measurement Canada.

(c) Due the age of EPI's communication equipment, compatibility issues with new meters have arisen, resulting in the need for modernization to support the ongoing renewal. These modernizations are occurring alongside the metering renewals. This concurrent modernization of AMI communications infrastructure will transform the system into a real-time analytics-driven platform. Improved communication range and data throughput, meter grid-edge computing for enhanced power quality monitoring, redundant data pathways and self-healing mesh topologies ensuring continuous meter connectivity during network or power disturbances, faster outage detection and restoration for customer communication,

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standardized bi-directional meter capability for future electrification. AMI 2.0 unlocks benefits in reliability, cybersecurity, operational efficiency, and policy responsiveness—key objectives under the OEB's *Renewed Regulatory Framework for Electricity*.

(d) This question asks EPI for information outside the forecast period in the DSP, which is not in scope nor relevant to the matters at issue in this 2026 cost of service application.

	2026	2027	2028	2029	2030
Forecasted total population of meters	64,765	65,365	65,965	66,565	67,165
Number of meters planned to be replaced	5,726	5,065	4,318	3,800	3,543
Number of meters planned to be replaced Meter replacement rate	5,726 8.8%	5,065 7.7%	4,318 6.5%	3,800 5.7%	3,543 5.3%
Number of meters seal expiring	6,568	5,154	15,728	3,897	6,656
Number of meters seal expiring Expired seal replacement rate	6,568 87.2%	5,154 98.3%	15,728 27.5%	3,897 97.5%	6,656 53.2%

(e) EPI has already reduced the pacing of its meter replacement program to the maximum extent possible while remaining in compliance with Measurement Canada obligations. EPI evaluated metering alternatives to accelerate its smart meter transition as part of its 2026–2030 Distribution System Plan (DSP) under Section 5.1.2.2.4 – Metering Renewal, which outlines the utility's strategic transition toward AMI 2.0. The alternatives were assessed in terms of cost effectiveness, regulatory compliance, operational continuity, and long-term system capability. EPI is migrating to AMI 2.0 at lifecycle pacing, with no acceleration. Choosing a reduced investment pacing plan would defer near-term capital spending but significantly elevate EPI's exposure to Measurement Canada non-compliance, reliability

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degradation, reduced customer confidence, and delayed achievement of AMI 2.0 smart-grid benefits.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-18

IT Software Investment
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 1 of 6, Section 5.1.2.4.5
Ref. 2 Exhibit 2, Attachment 2-C DSP Part 6 of 6, Attachment J, 20. IT Software, pp. 170-171

Preamble:
A number of major software expenditures are planned over the DSP forecast period, including a website re-design and transition to a new infrastructure virtualization solution in the test year.

Questions:
(a) Please explain how Entegrus Powerlines determines the need for and prioritizes non-security related software/system upgrades, e.g., website redesign.
(b) Have customers expressed dissatisfaction with the current website?
(c) Please discuss the pacing of IT software expenditures within the context of redesigning the website and adopting a new infrastructure tool in the test year such that IT software spending is 62% higher in 2026 than the forecast average from 2026 to 2030.

RESPONSE:

(a) EPI evaluates non-security related software and system upgrades, such as website enhancements, by leveraging customer engagement in combination with management's assessment of functionality, lifecycle replacement, and cost effectiveness.

(b) With respect to the website redesign project, customers expressed a preference for simplified navigation and more easily accessible information including business-focused content, public safety content, and outage updates. For customer engagement related to the website,

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please refer to Chapter 2 Appendix, Appendix 2-AC and Exhibit 1, Attachment 1-E.

(c) EPI requires a full website redesign in 2026 because the existing website no longer meets customer expectations and modern standards. The platform's layout and user interface has become outdated, limiting customers' ability to access key information, mobile functionality, and digital engagement options. The new design will modernize user experience, improve system performance, and align with EPI's broader digital transformation and customer service objectives. The transition to a new infrastructure virtualization platform was driven by a significant increase in licensing costs from the incumbent vendor, which rendered the existing solution unsustainable. EPI aligned the migration with its five-year server refresh cycle to optimize cost efficiency, minimize disruption, and ensure platform compatibility.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-19

Capital Contribution
Ref. 1: Exhibit 2, Attachment 2-C DSP Part 6 of 6, Attachment J, 1. Contributed Capital, section B.2

Preamble:
Entegrus Powerlines notes that provincial policies now require a 40-year revenue horizon for residential housing developments, which in turn have reduced the amount of capital contributions that Entegrus Powerlines collects from such customers.

Question:
(a) Please provide actual 2025 capital contributions to date.
(b) What proportion of customer contributions have historically come from housing developments?
(c) Please provide any calculations that Entegrus Powerlines has undertaken to quantify the impact to Entegrus Powerlines of these reduced capital contributions (e.g., from increased borrowing costs).

RESPONSE:

(a) Actual YTD October 2025 capital contributions are $2.47M.

(b) The proportion of customer contributions attributable to residential and subdivision developments fluctuates significantly from year to year. For the 2021–2024 period, the residential share ranged from approximately 28% to 62% of total contributed capital. On average, about 48% of customer contributions have historically originated from residential and subdivision developments.

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(c) The extension of revenue and connection horizons results in an approximate $150k reduction in contributed capital for the 2026 Test Year. As a result of the lower contributions, EPI anticipates the need to finance this amount through additional borrowing. Based on the company's average borrowing rate of 4.23%, this results in incremental annual interest expense of approximately $6k.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-20

Consideration of Non-Wire Solutions (NWS) to address system needs
Ref 1: Exhibit 2, Attachment 2C, Distribution System Plan, Part 1 of 6, p. 128

Preamble:
The NWS Guidelines require distributors to document their consideration of Non-Wires Solutions (NWS) when making investment decisions related to electricity system needs with an expected capital cost of $2 million or more, excluding general plant investments.

Entegrus Powerlines indicates that it has developed project screening procedures to determine when a capital project requires a Benefit-Cost Analysis (BCA) to assess the cost-effectiveness of NWS. It also notes that the screening process excludes projects unrelated to capacity or grid optimization (e.g., voltage stability or transfer capacity), as well as those below the $2 million threshold outlined in the NWS Guidelines.

Question(s):
(a) Please provide a copy of the project screening procedures referenced in the Distribution System Plan, including any criteria or decision trees used to determine whether a capital project requires a BCA.
(b) Please confirm whether NWS are considered as part of the distribution system planning process for projects below the $2 million threshold. If so, please describe the circumstances under which such consideration occurs and provide examples, if available.

RESPONSE:

(a) As outlined in Exhibit 2, DSP, Section 4.6 (NWSs to Address System Needs), EPI's project screening methodology is integrated into its planning practices and is consistent with the OEB's Non-Wires Solutions Guidelines for Electricity Distributors and the IESO's

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Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives. EPI has not developed any additional internal guidance documentation at this time, and assessments are conducted on an individual basis.

(b) For projects where NWS are identified as being a good potential solution, EPI will perform a BCA on a case-by-case basis regardless of anticipated cost, otherwise EPI uses the materiality threshold to determine if a BCA is required.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-21

Consideration of Non-Wire Solutions (NWS) to address system needs
Ref 1: Exhibit 2, Attachment 2C, Distribution System Plan, Part 1 of 6, p. 128

Preamble:
Entegrus Powerlines conducted a high-level NWS screening modelled after early BCA information for the Edgeware breaker in St. Thomas and concluded that an NWS does not currently present a technically or economically viable alternative to address the region's existing and forecasted load growth, noting that BESS would be approximately 135% to 280% more costly than traditional infrastructure investments.

Question(s):
(a) Please provide the documentation supporting this pre-assessment, including any assumptions, methodologies, cost estimates, and technical evaluations used to inform the conclusion.

RESPONSE:

(a) EPI conducted a high-level technical and financial feasibility assessment of NWS to address capacity constraints at Edgeware TS, comparing a Battery Energy Storage System (BESS) based alternative to the proposed addition of a fifth feeder.

Contingency modelling based on historical feeder peak data was used to quantify stranded load (excess load beyond feeder's serving capacity) during the loss of one or more feeders based on present-day load conditions (not including forecasted growth).

Over forty stranded load events were analyzed for (n-1) contingency scenario (loss of 1 feeder), and the BESS was sized to mitigate the most severe outage event, requiring approximately 5.2 MW of peak capacity and 29.5 MWh of energy over a 12-hour period.

Capital cost estimations for a BESS this size were sourced from National Renewable Energy Laboratory (2023)[1] cost projections across multiple cost scenarios. The assessment concluded that the acquisition costs of the required BESS would be approximately 135% to 280% more costly than the construction of a traditional feeder, with limited capability to support load growth.

The core assumptions made in this analysis were:

- The bi-directional inverter for the BESS was assumed to have symmetric charge and discharging profiles under constant peak power (5.2 MW), allowing it to fully charge within 12 hours between load cycles.
- Analysis was based on historical feeder peak data (2022-2024) and median load conditions for contingency driven stranded load only, excluding the region's forecasted load growth.
- BESS was not oversized to account for battery degradation over time.
- Cost comparisons accounted only for the capital cost of the BESS and did not include the operating and maintenance costs over its lifecycle.

[1] National Renewable Energy Laboratory. (2023). Annual Technology Baseline: Electricity 2023 - Data. https://atb.nrel.gov/electricity/2023/data

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-22

Consideration of Non-Wire Solutions (NWS) to address system needs
Ref 1: Exhibit 2, Attachment 2C, Distribution System Plan, Part 6 of 6, p. 247

Preamble:

Entegrus Powerlines noted the Section 5.1.3.3.2 of the DSP provides further insight into Entegrus Powerlines' NWS considerations within its system planning process, specifically addressing capacity enhancement strategies in accordance with regulatory requirements.

Question(s):
(a) Please confirm the location of Section 5.1.3.3.2 within the DSP, including the relevant document/file name and page number(s).

RESPONSE:
(a) The reference to Section 5.1.3.3.2 within the DSP was incorrect. The correct reference is Exhibit 2, Section 4.6, "NWSs to Address System Needs (5.3.5)".

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-23

Ref 1: Filing Requirements Chapter 2 Appendices, Appendix 2BA
Ref 2: Filing Requirements Chapter 2 Appendices, Appendix 2AB

Preamble:

Entegrus Powerlines indicates in reference 2 that capital expenditures equals capital additions in a year. OEB staff notes the following differences between reference 1 and reference 2:

	2018	**2020**	**2025**
2AB	10,419,724	13,175,616	22,003,000
2BA	37,449,238	13,183,236	22,573,517
Difference	**(27,029,514)**	**(7,620)**	**(570,517)**

Question(s):
(a) Please explain and reconcile the difference between reference 1 and reference 2.
(b) Please provide updated evidence as necessary.

RESPONSE:

(a) <u>2018 Variance</u>

The merger between EPI and STEI was completed in 2018. The differences between Appendix 2-AB and Appendix 2-BA for that year reflect the inclusion of assets transferred

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from STEI at the merger date, in addition to EPI's regular capital additions. STEI's assets were transferred to EPI at their net book value.

<u>2020 Variance</u>

The $7,620 difference between Appendix 2-AB and Appendix 2-BA for 2020 reflects the addition to a previously recognized capital lease, which is not recorded as a capital expenditure in Appendix 2-AB.

<u>2025 Variance</u>

In Appendix 2-AB, EPI inadvertently provided an incorrect response to the question "Capital Expenditures = In-Service Additions." The correct response should have been "No," as certain capital expenditures incurred in a given year are not placed into service until the following year. The $570,517 difference between Appendix 2-AB and Appendix 2-BA for 2025 is due to the change in CWIP.

(b) N/A - no updates to evidence are necessary.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-24

Ref 1: Filing Requirements Chapter 2 Appendices, Appendix 2BA

Preamble:

OEB staff noted the following differences in the closing 2017 balance and opening 2018 balances for fixed assets and accumulated depreciation in reference 1. The opening and closing balances should be the same.

Fixed Assets	**2017**
Closing	130,843,341
Opening	98,562,316
Difference	**32,281,025**
Accumulated Depreciation	
Closing	(20,626,557)
Opening	(15,898,138)
Difference	**(4,728,419)**

Question(s):

(a) Please explain and reconcile the difference in fixed assets and accumulated depreciation as noted in the table.

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(b) Please provide updated evidence as necessary.

RESPONSE:

(a) For the purposes of the Application, the Appendix 2-AB asset continuity schedules for 2016 and 2017 were presented on a combined basis for legacy EPI and STEI. The merger between EPI and STEI was completed in 2018. To reflect that STEI's assets were transferred to EPI at their net book value at the merger date, STEI's gross cost and accumulated depreciation as of December 31, 2017 were removed from the January 1, 2018 opening balances. The 2018 Appendix 2-AB asset continuity schedule in the Application therefore presents opening balances for legacy EPI, with the additions column including both the assets transferred from STEI and EPI's regular capital additions. The cost variance of $32,281,025 represents the gross asset value of STEI's assets as at December 31, 2017, while the depreciation variance of ($4,728,418) represents STEI's accumulated depreciation as at that date.

(b) N/A - no updates to evidence are necessary.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-5

[Exhibit 2, p.5; Appendix 2-BA] Entegrus states that 'EPI's capital expenditures are equivalent to in-service additions'; however, Appendix 2-BA shows changes in construction work in progress ("CWIP") which would indicate this is not the case.

a. Please explain the $1,120,516 (Cell E925) addition to CWIP in 2024, which appears to be scheduled to go into service in 2025 (Cell F989).
b. Please explain the $550,000 (Cell E989) addition to CWIP in 2025, which appears to be scheduled to go into service in 2026 (Cell F1053).
c. Please explain the $550,000 (Cell E1053) addition to CWIP in 2026. When is this asset scheduled to go into service?
d. Please explain the entries shown for accumulated depreciation for CWIP, e.g. in Cells K540, J604, J668 and K668.

RESPONSE:

a. In Appendix 2-AB, EPI inadvertently provided an incorrect response to the question "Capital Expenditures = In-Service Additions." The correct response should have been "No," as certain capital expenditures incurred in a given year are not placed into service until the following year. The $1,120,516 addition represents CWIP in 2024 that is placed into service in 2025.

b. The $550,000 addition represents CWIP in 2025 that is scheduled to be placed into service in 2026.

c. The $550,000 addition to CWIP in 2026 is expected to go into service in 2027.

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d. Following the merger of legacy EPI and STEI, it was identified that STEI had depreciated its spare parts prior to the merger. EPI subsequently reversed this depreciation as the parts were capitalized and recognized as in-service additions.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-6

[Exhibit 2; Appendix 2-AA]

a. The average percentage contributed capital from 2016 to 2025 is 45% of gross System Access capital. Please explain why for the forecast period the average contributed capital has dropped to 38%.

b. Please break out the forecasted contributed capital by the projects in System Access: Customer Conns: Commercial & Industrial, Customer Conns: Residential & Subdivisions, Engineering Support Capital, Miscellaneous System Access and Third-Party Attachments.

RESPONSE:

a. Please refer to Exhibit 2, 2026 DSP, Attachment J – Material Investment Narratives – 01 Contributed Capital. The reduction in the average percentage of contributed capital between the Historical Period (2016–2025) and the Forecast Period (2026–2030) is primarily attributable to two factors:

   i. **Lower Internet Service Provider ("ISP") Activity:** During the Historical Period, System Access investments were significantly influenced by ISP-driven make-ready work, for which customer contributions were recovered at or near 100%. The conclusion of major ISP expansion programs in EPI's service territory in 2023 has reduced these high-contribution projects in the Forecast Period.

   ii. **Amendments to the Distribution System Code (EB-2024-0092):** Effective December 2024, DSC amendments extending the revenue horizon for residential subdivision economic evaluations from 25 to 40 years have reduced the amount of contributed capital payable by residential customers. This change lowers the average contribution rate applied to new residential connections in the Forecast Period.

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b. Please see below for the requested breakout of the forecasted contributed capital by the projects in System Access.

Table 1: Contributed Capital Breakdown

	2026	**2027**	**2028**	**2029**	**2030**
Customer Conns: Commercial & Industrial	573,501	590,490	607,753	622,150	636,978
Customer Conns: Residential & Subdivision	964,315	990,645	1,019,376	1,035,774	1,052,652
Third Party Attachments	133,229	118,178	121,724	125,376	129,137
Total Contributed Capital	**1,671,046**	**1,699,313**	**1,748,852**	**1,783,299**	**1,818,767**

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-7

[Exhibit 2, Table 2-18]

Please provide an update on the status of the capital work forecasted to be done in 2025.

RESPONSE:

EPI's 2025 capital program is progressing largely as planned, except for additional expenditures required to meet customer-driven system expansion needs. The additional spending has been partially offset by corresponding capital contributions. As of October 31, 2025, total spending (net of contributed capital) is forecasted to be materially consistent with the capital plan. Please refer to the response to Interrogatory 1-SEC-2 Attachment 1 (Appendix 2-BA tab) for a summary of 2025 capital expenditures and CWIP as of October 31, 2025.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-8

[Exhibit 2, Table 2-26; Appendix 2-D]

Please provide details of how Entegrus determined the OM&A allocated to capital for 2026.

RESPONSE:

EPI forecasted the OM&A allocated to capital for 2026 by escalating the 2024 actual amounts using (1) the forecasted percentage increase in FTEs and (2) the OEB inflation factors applicable for each of 2025 and 2026.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-9

[Exhibit 2, Attachment 2-C Distribution System Plan ("DSP") (1of6), p.35]

a. What is Entegrus' estimate of the potential load of the St Thomas Volkswagen electric battery production facility?

b. Has Entegrus made any adjustments to its capital plan or load forecast to account for this load?

RESPONSE:

a. As noted in Exhibit 2, Attachment 2-C Distribution System Plan ("DSP") (1of6), p.35, the St. Thomas Volkswagen electric battery production facility is located outside of EPI service territory.

b. No.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-10

[Exhibit 2, DSP (1of6), p.76]

Is Entegrus proactively upgrading transformers to 100 kVA, or is this done only upon replacement for other reasons?

RESPONSE:

EPI installs 100 kVA transformers for new residential distribution connections, as well as upon replacement (See Exhibit 2, Attachment 2-C, DSP Section 4.1.2, subsection *Standardization of Design and Capacity Planning*). Based on customer engagement, EPI also plans to proactively identify and replacing its most at-risk transformers with 100 kVA units (See DSP Section 3.2.1.2.2, subsection *Outcomes and Impact on the DSP* and Exhibit 2, DSP, Attachment J "Material Investment Narratives" 17.Capacity Enhancements).

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-11

[Exhibit 2, DSP (1of6), Tables 5-22 to 5-25; Appendix 2-AB]

a. Please explain the basis for numbers shown for 2025 Plan and for 2025 Forecast in the Tables 5-22 to 5-25.
b. Please explain the variance between the numbers in Tables 5-22 to 5-25 and the 2025 Actual and 2025 Plan the numbers shown in Appendix 2-AB.

RESPONSE:

a. The “2025 Plan” represents the capital investment levels per EPI’s 2021 DSP. The “2025 Forecast” represents EPI’s updated 2025 corporate capital budget.

b. Tables 5-22 to 5-25 in the 2026 DSP are presented using the original 2021 DSP project structure for comparability with the historical plan. In Appendix 2-AB, all capital expenditures have been recategorized to align with the revised program structure adopted in the 2026 DSP. The relationship between the 2021 DSP and 2026 DSP project categorizations is shown in Table 5-2 of the 2026 DSP. Variance explanations are provided in the last column of Tables 5-22 to 5-25.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-12

[Exhibit 2, DSP (1of6), Table 4-1 and Tables 5-27 to 5-30]

The listed tables show a priority ranking for each project for the five years of the DSP.

a. Please provide the details on how these rankings were determined, i.e. showing the scoring for each project by objective in Table 4-1.

b. Please provide a priority ranking for each of the projects in 2026 and show how the rankings were determined.

c. Were there any other projects planned for 2026 that were deferred based on the priority ranking? If so, please explain.

RESPONSE:

a. Please see below for the full table outlining the specific scoring for each project which determined the 2026 project ranking and was applied consistently across the Forecast Period:

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Line No.	Project	Public/Employee Safety - 5	Environment - 4	Reliability - 3	Grid modernization - 3	Operational Efficiency & Regulatory Requirements - 2	Cost Effectiveness - 3	Total Score	Rank
1	**SYSTEM ACCESS**								
2	Contributed Capital	-	-	-	-	-	-	-	-
3	Customer Conns: Commercial & Industri	1	0	3	5	5	5	54	8
4	Customer Conns: Residential & Subdivisi	1	0	3	5	5	5	54	9
5	Engineering Support Capital	2	3	2	3	5	5	62	4
6	Miscellaneous System Access	0	0	1	0	5	4	25	19
7	Third Party Attachments	5	0	0	1	5	5	53	10
8	**SYSTEM RENEWAL**								
9	Critical Defect Replacements	5	2	5	1	3	3	66	2
10	Emergency Response	5	2	5	2	5	2	70	1
11	Metering Renewal	0	0	0	5	5	5	40	14
12	Miscellaneous System Renewal	0	0	3	3	0	2	24	20
13	Operation Support Capital	2	1	5	3	5	5	63	3
14	Pole Replacement	2	0	5	2	2	2	41	13
15	Transformer Replacement	0	1	5	4	3	4	49	12
16	Voltage Conversion	0	0	3	5	0	5	39	15
17	**SYSTEM SERVICE**								
18	Miscellaneous System Service	0	0	1	5	0	0	18	22
19	System Modernization and Planning	2	0	4	5	5	3	56	7
20	Capacity Enhancements	0	0	5	5	4	4	50	11
21	**GENERAL PLANT**								
22	Building	4	1	0	0	0	4	36	16
23	IT Hardware	3	0	5	5	3	2	57	6
24	IT Software	3	0	5	5	4	2	59	5
25	Miscellaneous General Plant	3	1	0	0	2	0	23	21
26	Rolling Stock	4	0	0	1	4	0	31	17
27	Tools	4	0	0	0	4	0	28	18

b. Please see part a. above.

c. The preliminary budget envelope was set before the prioritization process, then prioritization was done with projects expected to fit within the preliminary envelope. While significant effort was spent to ensure appropriate project pacing, an additional $741k in spending (less than 4% of the total) was deferred through the prioritization process to fit within the final budget envelope.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-13

[Exhibit 2, DSP (2of6) Attachment A 2021-2025 DSP, Attachment C, Asset Condition Assessment ("ACA") 2021 Table 0-2 and DSP (3of6) Attachment B, ACA 2024, Table 0-2]

a. Please explain the decrease in average HI from 2021 to 2024 for steel, concrete poles and underground primary cables.
b. Please confirm that all "Pole-Tran" style transformers in the Pole-Trans and Platform Transformers class were replaced with pad-mounted units by the end of 2024.

RESPONSE:

(a) **For Steel and Concrete Poles**:
EPI no longer installs either steel or concrete poles. The Health Index is calculated purely by age, as such the HI will decrease as the population of these assets ages.
For Primary Cable:
Primary cable received a material update to its Health Index calculation in the current ACA. The new methodology better represents actual asset condition. See Exhibit 2, DSP Section 3.1.3 "Data Collection Improvements and Asset Condition Assessment" and Asset Condition Assessment Report, 4.2.3 "Methodology Improvements".

(b) Confirmed (see Exhibit 2, DSP Section 3.1.3, subsection *Submersible Transformer Conversion Program* and DSP Material Investment Narrative #13: *Transformer Replacement*).

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-14

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 09. Metering Renewal, p.68]

a. Entegrus states that it "had applied for a 6-year extension" for the approximately 5,000 meters that "tested poorly during the 2nd seal period sampling in 2024". Please provide an update to the status of this request.
b. Will Entegrus be able to ask for an extension for any of the approximately 39,700 meters seal that will expire during the 2026-2030 period?
c. Please provide the number of meters replaced each year 2021-2025 and forecasted to be replaced each year 2026-2030.
d. When is Entegrus planning to deploy AMI 2.0?

RESPONSE:

a. Based on the testing results, and in accordance with Measurement Canada regulation, the six year extension requested for the 5,000 meters was reduced to 2-years, with no further sampling or extensions permitted. The seals on these meters will now expire in 2026, rather than 2030 as originally sought.

b. Yes, the plan assumes that all of those meters going in for their first sampling will receive full extensions.

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c.

Year	**2021**	**2022**	**2023**	**2024**	**2025**
Number of Meters replaced	3,106	4,920	4,291	6,402	5,722

For meters anticipated to be replaced over the forecast period please see the response at 2-Staff-17 (d).

d. Please see the response at 2-Staff-17 (a)-(c).

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-15

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 11. Operations Support Capital, p.84]
Please explain which "large-scale investments in the distribution system" in 2026 this budget will be spent on.

RESPONSE:
The 2026 budget will be spent primarily on municipally driven construction to rebuild the Chatham Bloomfield Road / 401 crossing, as well as on multiple conversion projects, including Strathroy Sub 21, Strathroy Sub 24, and Blenheim East.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-16

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 12. Pole Replacements]

Please provide the number of poles replaced in each year 2021-2024 and forecasted to replace in each year 2025-2030. Please break the number down into emergency replacement, planned replacement, replacement due to voltage conversion, etc.

RESPONSE:

Please see the table below.

Table 1: EPI's Historical and Forecasted Pole Replacement by Year

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emergency Response	43	38	49	27	37	37	37	37	37	37
Planned Replacements	80	111	73	88	64	64	64	64	64	64
Voltage Conversion	150	118	167	146	202	153	255	199	309	293
Total Poles Replaced	273	267	289	261	303	254	356	300	410	394

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-17

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 13. Transformer Replacement]

Please provide the number of transformers replaced in each year 2021-2024 and forecasted to replace in each year 2025-2030.

Please break the number down into emergency replacement, planned replacement, replacement due to voltage conversion, etc.

RESPONSE:

Please see the table below.

Table 1: EPI's Historical and Forecasted Transformer Replacement by Year

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emergency Response	24	24	33	8	9	9	9	9	9	9
Planned Replacements	10	22	19	24	9	27	38	36	36	35
Voltage Conversion	64	47	61	78	76	71	100	100	99	73
Total Transformers Replaced	98	93	113	110	94	107	147	145	144	117

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-18

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 14. Voltage Conversion]

a. Please provide a listing of the 4 kV stations that will be converted, including the Health Index for each station's assets.
b. Please indicate the scheduled year for conversion of each station.

RESPONSE:

a. The table below provides the list of stations that are scheduled to be fully converted to 27.6 kV within the forecast period. Please note station decommissioning lags a station being fully offloaded/converted (where other factors do not apply, by approximately one year).

Station Name	**Strathroy Sub 24**	**Blenheim East**	**Strathroy Sub 21**	**Wheatley**	**Strathroy Sub 23**
Voltage (kV)	4.16	4.16	4.16	4.16	4.16
Station TX Health Index	Fair	Fair	Poor	Fair	Fair
Circuit Breaker Health Index	Below DAI Threshold	N/A	Good	N/A	N/A
Switches Health Index	Very Poor	Very Poor	Very Poor	Very Poor	Very Poor
Batteries Health Index	N/A	N/A	N/A	N/A	N/A
Yards Health Index	Very Good	Very Good	Very Good	Very Good	Very Good
Scheduled Year of Conversion Completion	2027	2029	2030	2030	2030

b. Please refer to the last line of the above table.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-19

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 16. System Modernization and Planning]
Please indicate which specific projects will be done under this budget.

RESPONSE:

As detailed in *Section 5.1.2.3.1 – System Modernization and Planning* of the 2026 DSP, this budget encapsulates EPI's spending on smart switches for increased segmentation, automation, and control room visibility to improve overall system reliability by improving system segmentation and introducing self-healing capabilities to reduce outage scopes automatically. EPI also installs single switches on smaller embedded feeders for increased system visibility and control as operational or reliability needs require. It is important to note that Table 1 is a snapshot of EPI's current investment strategy for the 2026-2030 Forecast Period. As stated in *Section 3.3.1.1.4 – Worst Performing Feeder (Monitor)*, EPI monitors customer reliability on a per feeder basis and may reallocate modernization investments amongst communities and feeders as appropriate.

Table 1 - List of System Modernization and Planning projects to be completed over the 2026-2030 Forecast Period

Community	Completion Year	Number of Switches
St. Thomas	2026	4
St. Thomas	2027	4
Wallaceburg	2028	1
St. Thomas	2028	3
Chatham	2029	2
Tilbury	2029	1
Wheatley	2029	1
Strathroy	2030	3

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-20

[Exhibit 2, DSP (6of6), Attachment J Material Investment Narrative, 17. Capacity Enhancements]

Please indicate which specific projects will be done under this budget.

RESPONSE:

As detailed in Exhibit 2, DSP, Section 5.1.2.3.3 – Capacity Enhancements, this budget includes the staged voltage conversion projects of the 8 kV network in Mount Brydges to ensure the integrity of the 8kV system by preventing station overloads as load growth occurs in the community.

The Mount Brydges conversion program is staged as follows:

- **2026:** CN-MTB Metering Point:
  Initial establishment of 27.6 kV supply to the community including metering costs.
  CN-MTB MBF3 Phase 1:
  Initial conversion work to ensure the new metering point meets minimum load requirements per IESO rules.
- **2027:** CN-MTB MBF3 Phase 2
  Incremental conversion to displace load growth and maintain 8kV system integrity
- **2028:** CN-MTB MBF3 Phase 3
  Incremental conversion to displace load growth and maintain 8kV system integrity
- **2029:** CN-MTB MBF3 Phase 4
  Incremental conversion to displace load growth and maintain 8kV system integrity
- **2030:** CN-MTB MBF3 Phase 5
  Incremental conversion to displace load growth and maintain 8kV system integrity

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-21

[Exhibit 2, Attachment 2-C DSP (6of6), Attachment J Material Investment Narrative, 20. IT Software]

Please show the budget for each of the two specified projects planned for 2026.

RESPONSE:

The budgets for the two specified projects planned for 2026 are as follows: full website redesign ($109k) and transition to a new virtualization platform ($175k).

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-22

[Exhibit 2, Attachment 2-C DSP (6of6), Attachment J Material Investment Narrative, 22. Rolling Stock]

a. Please provide details of how Entegrus determines the Asset Replacement Criteria and how it is met.

b. Please provide a full listing of Entegrus' fleet, including age, condition and year of planned replacement.

c. Please break out the forecasted budget by vehicle to be replaced.

d. Please provide the status of the vehicles scheduled for 2026, e.g. have they been ordered, when is the expected delivery date?

RESPONSE:

(a) Please see Exhibit 2, Attachment 2-C, DSP, Section 4.9.

(b) The following tables contain the full listing of EPI's fleet, sorted by vehicle type. The tables contain the year of the vehicle, make of the truck, the location and the planned replacement year. EPI monitors fleet condition through third-party inspections and maintenance cost tracking, which inform replacement decisions under its Fleet Purchasing Policy. The condition variable does not lend itself to a one-or-two word description in a table. Vehicle age and utilization thresholds guide replacement eligibility, while individual condition assessments determine whether refurbishment or life extension is warranted.

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Truck #	Type	Year	Make of Truck	Community	Replacement
Bucket Trucks					
H05BK16	Single bucket	2005	International Altec 58 ft	Chatham	2031 & Beyond
H07BK06	Double bucket	2007	International Posi-Plus 55ft	Chatham	2031 & Beyond
H07BK11	Single bucket	2007	International Posi Plus 46 ft	Chatham	2031 & Beyond
H11BK08	Single bucket	2011	International Posi-Plus 42 ft	Chatham	2026
H13BK14	Double bucket	2013	International Posi-Plus 68ft	Chatham	2029
H16BK20	Single Bucket	2016	Freightliner Posi Plus 46Ft Material	Chatham	2031 & Beyond
H23BK12	Single Bucket	2023	46' Freightliner Posi-Plus	Chatham	2031 & Beyond
H24BK17	Double Bucket	2024	Freightliner Posi-Plus 55 ft plus elevator	Chatham	2031 & Beyond
M14BK05	Single bucket	2015	Freightliner Posi-Plus 42 ft	St. Thomas	2029
M15BK22	Double bucket	2015	Freightliner Posi-Plus 65ft	St Thomas	2030
H13BK9102	Single bucket	2013	International 4400 SBA	St.Thomas	2028
H19BK9125	Single bucket	2019	46' Freightliner Posi-Plus	St.Thomas	2031 & Beyond
H21BK9103	Double Bucket	2020	65' Freightliner Posi-Plus	St.Thomas	2031 & Beyond
H17BK15	Single bucket	2017	Ford F-550 37" Posi	Chatham	2027
Digger Derrick					
H12DD05	RBD	2012	International Commander 47 ft	Chatham	2031 & Beyond
H23DD04	RBD	2021	Freightliner Commander 47 ft	Chatham	2031 & Beyond
H25DD03	RBD	2025	Freightliner Terex	Chatham	2031 & Beyond
H11DD9101	Digger Derrick	2011	Freight - Liner M2 - 106	St. Thomas	2031 & Beyond
H14DD9119	Corner Mount	2014	Freight - Liner M2 - 106	St. Thomas	2031 & Beyond
H23DD06	Corner Mount	2024	Freightliner-Wajax/Terex - C-4047	St Thomas	2031 & Beyond
Dump Trucks					
H13DP66	Dump	2013	Ford F-550 Dump Truck	Chatham	2027
H22DP76	Dump	2022	Ford F-550 Dump Truck	Chatham	2031 & Beyond
M12DP5	Dump	2012	Ford F550 dump truck	St. Thomas	2028
H17DP9213	Dump	2017	Ford F550 Dump Truck	St. Thomas	2031 & Beyond
Pickup Trucks					
H14PU124	Pickup	2014	Ram 1500 Quad 4X2	Chatham	2031 & Beyond
H14PU127	Pickup	2014	Ram 1500 Quad 4X2	Chatham	2031 & Beyond
H15PU130	UDG Service Truck	2015	F-550 Ford	Chatham	2031 & Beyond
H16PU120	Pickup	2016	Ram 1500 Quad 4 x 4	Chatham	2028
H17PU03	Pickup	2017	Chev-Silverado	Chatham	2027
H17PU128	Pickup	2017	F-250 Super Cab	Chatham	2028
M17PU175	Pickup	2017	F-150 Super Cab	Chatham	2029
H18PU001	Pickup	2018	F-250 Super Cab	Chatham	2031 & Beyond
H18PU16	Pickup	2018	Chevy-Silverado 1500	Chatham	2031 & Beyond
H18PU18	SUV	2018	Escape SE	Chatham	2031 & Beyond
H21PU14	Pickup	2021	Dodge RAM	Chatham	2031 & Beyond
H21PU19	Pickup	2021	GMC Sierra Elevation	Chatham	2031 & Beyond
H24PU121	Pickup	2024	Dodge Ram 3500	Chatham	2031 & Beyond
H24PU122	Pickup	2024	Chevrolet Silverado	Chatham	2031 & Beyond
H24PU123	Pickup	2024	Chevrolet Silverado	Chatham	2031 & Beyond
H25PU126	Pickup	2025	Ford F-250-Extended Cab	Chatham	2031 & Beyond
H16PU116	Pickup	2016	GMC 4 X 4 Pickup	St. Thomas	2026
H17PU9208	Pickup	2017	Ford-150-Extended Cab	St. Thomas	2028

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H17PU9209	Pickup	2017	Ford F 150-Crew Cab	St. Thomas	2031 & Beyond
H19PU386	Pickup	2019	Chevrolet Silverado	St. Thomas	2031 & Beyond
H19PU195	Pickup	2019	GMC Sierra	St. Thomas	2029
H21PU15	Pickup	2021	GMC Sierra Elevation	St. Thomas	2031 & Beyond
H21PU17	Pickup	2021	Ford F-250-Extended Cab	St. Thomas	2031 & Beyond
H21PU20	Pickup	2021	Dodge Ram 1500	St. Thomas	2031 & Beyond
H22PU21	Pickup	2022	Ford F250	St. Thomas	2031 & Beyond
H23PU125	Pickup	2023	Ford F150 XLT	St. Thomas	2031 & Beyond
S14PU193	Pickup	2014	Ram 1500 Quad 4 x 4	Chatham	2031 & Beyond
S15PU37	Pickup	2015	2015 Chev Colorado	Chatham	2025
SV16VN12	Pickup	2016	2016 Chev Colorado	Chatham	2026
SV17VN35	GM Colorado	2017	2017 Chev Colorado	Chatham	2027
SV19VN36	GM Colorado	2019	2019 Chev Colorado	Chatham	2031 & Beyond
SV21PU59	GM Colorado	2021	2021 Chev Colorado	Chatham	2031 & Beyond
SV24PU23	Pickup	2024	2024 Chevrolet Silverado	Chatham	2031 & Beyond
SV25PU194	Pickup	2024	2024 Chevrolet Silverado	Chatham	2031 & Beyond
M16PU09	GM Colorado	2016	2016 Chev Colorado	Strathroy	2026
H25PU127	Pickup	2025	2025 Chevrolet Colorado	Chatham	2031 & Beyond
H17PU150	Pickup	2017	F-250 Super Cab	Chatham	2027
Cars/Vans/SUVs					
H17VOLT99	Car	2016	Chevy Volt	Chatham	2031 & Beyond
H16SUV32	SUV	2016	Jeep Cherokee	Chatham	2026
H16VN11	VAN	2016	Nissan VN	Chatham	2031 & Beyond
H21PU06	SUV	2021	Ford Bronco	St.Thomas	2031 & Beyond
H21PU12	SUV	2021	Ford Bronco	St.Thomas	2031 & Beyond
H23SUV87	SUV	2023	Toyota Highlander	Chatham	2031 & Beyond
H25SUV90	SUV	2024	Toyota Highlander - Hybrid	Chatham	2031 & Beyond
H19SUV88	SUV	2019	Ford Edge	Strathroy	2031 & Beyond
H22SUV89	SUV	2022	Toyota Highlander	Chatham	2031 & Beyond
H17VN4011	SUV	2018	Ford Edge	Chatham	2028

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Truck #	Type	Year	Make of Truck	Community
Trailers				
ATUT66	Trailer	1995	Yellow Pole Trailer North	Chatham
H02UT84	Trailer	2002	double axle material trailer	Chatham
H03UT47	Trailer	2003	Roose single axle hydraulic reel trailer	Chatham
H11RT74	reel trailer	2011	J&J	Chatham
H11UT34	Trailer	2011	Black Utility trailer	Chatham
H18PT1111	Pole Trailer	2018	Pole Trailer	Chatham
H20UT59	12' x 6' Trailer	2020	Single Axle Utility Trailer	Chatham
H23UT75	Utility Trailer	2023	Single Axle Utility Trailer	Chatham
H23UT76	Utility Trailer	2023	Single Axle Utility Trailer	Chatham
H24MT02	Material Trailer	2024	Bluewater Trailer 12' x 80"	Chatham
H24MT04	Material Trailer	2024	Bluewater Trailer 14' x 80"	Chatham
H24RT02	Reel Trailer	2024	Felling Reel Trailer	Chatham
H25PM43	Pulling Machine	2024	Timberland Pulling Machine	Chatham
H25TM42	Tension Machine	2024	Timberland Tension Machine	Chatham
H25MT07	Material Trailer	2026	Canada Trailers	Chatham
H91UT51	Trailer	1991	Yellow PCB Trailer	Chatham
H95UT46	Trailer	1995	Pole Trailer	Chatham
H01UT9560	Pole Trailer PT-1	2001	PT-4	St.Thomas
H18PT1110	Pole Trailer	2018	Pole Trailer	St.Thomas
H22UT9559	Pole/Utility Trailer	2022	Reel Trailer - Reelstrong Utility Fleet	St. Thomas

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H24MT01	Material Trailer	2024	Bluewater Trailer 12' x 80"	St Thomas
H24MT03	Material Trailer	2024	Bluewater Trailer 12' x 80"	St Thomas
H24RT01	Reel Trailer	2024	Felling Reel Trailer	St Thomas
H25ST05	Utility Trailer	2025	Bluewater Trailers 82x14	St Thomas
H62UT9555	Reel Trailer	1962	Smith Bros. HCT	St.Thomas
H67UT9556	Pole Trailer	1967	King	St.Thomas
H80UT9557	Pole Trailer PT-2	1980	Yarmouth PT-4	St.Thomas
H87UT9552	Line Puller	1987	Timberland DPT	St.Thomas
H88UT9553	Line Tensioner	1988	Timberland DPT	St.Thomas
M86TL4	reel trailer	1986	Util-Equip tandem trailer (w/ reel stands)	Strathroy
H25HST06	Trailer	2026	Single Axle Aluminum Utility Trailer 7'x14'	Chatham
Other				
H04WC13	chipper	2004	Vermeer chipper	Chatham
H10RTV12	ATV	2010	Kubota - Model RTV900G9-A	Chatham
HATWC12	chipper	1995	Vermeer chipper	Chatham
VEFL04	forklift	1996	Hyster Forklift	Chatham
VELD05	bobcat loader	1994	Bobcat loader 773	Chatham
H13T1-L	Mobile Substation	1950	Mobile Substation	Chatham
9550	Brush Chipper	1992	Vermeer 1250 BC	St.Thomas
9551	Hi-Pot Tester	NA	NA	St.Thomas
9554	Mobile Transformer	1955	Smith Bros.	St.Thomas
9559	Mobile Substation	1998	JJTM AT3	St.Thomas
9561	EZ Hauler	2009	SPD4100	St.Thomas
H24ATV16	ATV	2024	Can Am Outlander 700XT	St Thomas
H24MD01	Mini Derrick	2023	Skylift ES MDS6000-LP	St.Thomas
M98LT1	forklift	1998	1998 Toyota Forklift	Strathroy
H24FL06	Forklift	2024	Hyster 135 Forklift	St Thomas

(c) EPI provides vehicle-level detail of the Rolling Stock renewal budget. Further detail of the existing vehicle in EPI's fleet is found in Attachment 2-C DSP (6of6), Attachment J Material Investment Narrative, 22. Rolling Stock.

Table 1: EPI's Forecasted Rolling Fleet Budget

Replacement Year	Existing Vehicle - Vehicle Number	Forecasted Expenditure
2026	H11BK08	$523,000
	H16SUV32	$65,000
	H16PU116	$80,000
	SV16VN12	$85,000
	M16PU09	$65,000
	New Bucket Truck – Chassis Only (WIP)	$139,000
	TOTAL	**$957,000**
2027	H17BK15	$500,000

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	H13DP66	$105,000
	H17PU03	$75,000
	H17PU150	$75,000
	SV17VN35	$65,000
	New Bucket Truck (Remaining Balance)	$375,000
	TOTAL	**$1,195,000**
2028	H13BK9102	$504,000
	M12DP5	$100,000
	H17VN4011	$70,000
	H17PU128	$80,000
	H17PU9208	$70,000
	H16PU120	$70,000
	TOTAL	**$894,000**
2029	M14BK05	$500,000
	H13BK14	$600,000
	H19PU195	$70,000
	M17PU175	$70,000
	TOTAL	**$1,240,000**
2030	M15BK22	$585,000
	H88UT9553	$385,000
	TOTAL	**$970,000**

(d)

Vehicle	**Status**
Large Single Bucket	Delivery/In Service Q2 2026
Large Single Bucket (Chassis Only)	Delivery Q1 2026, In Service 2027
4x Small Vehicles	Will be ordered and delivered in 2026

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2-SEC-23

[Exhibit 2, DSP]

a. Under which program(s) does Entegrus replace overhead and underground conductors? b. Please provide the number of km of overhead and underground conductors replaced in 2021-2024 and forecasted to be replaced in years 2025-2030.

RESPONSE:

a. EPI replaces overhead and underground conductors through the following programs:
    a. System Access (see DSP Sections 3.1.2.1 and 5.3.1)
        i. Third Party Attachments
        ii. Customer Conns: Commercial & Industrial
        iii. Customer Conns: Residential & Subdivision
        iv. Miscellaneous System Access
    b. System Renewal (see DSP Sections 3.1.2.2 and 5.3.2)
        i. Critical Defect Replacement
        ii. Emergency Response
        iii. Miscellaneous System Renewal
        iv. Voltage Conversion
    c. System Service (see DSP Sections 3.1.2.3 and 5.3.3)
        i. Capacity Enhancements

b. EPI's primary conductor replacement is as follows:

Primary Conductor Replacement per year (km)	
2021-2025	**2026-2030**
42.6	34.9

Note that EPI does not track conductor installation reasoning in its historical dataset. The above historical values are estimations based on a best effort reconstruction.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2-VECC-5

Reference: Exhibit 2, DSP, pages 123 and 126

Preamble:

The Application states:

"The residential sector, comprising over 90% of EPI's customer base, is a primary driver of load growth. Recent subdivision developments, coupled with government housing mandates such as Ontario's Bill-23:

More Homes Built Faster Act (2022), are expected to sustain this growth. As residential electrification accelerates - driven by the adoption of EVs, heat pumps, and other electric technologies - demand will continue to rise." (page 123)

"Although fewer in number, Commercial and Industrial customers can drive significant demand growth, often requesting unprecedented load capacities. These connections can quickly deplete available capacity, especially in areas poised for industrial or commercial development." (page 126)

a) For purposes of the DSP what were EPI's assumptions regarding the annual growth in Residential connections and load for the next five years?

b) For purposes of the DSP what were EPI's assumptions regarding the annual growth in Commercial and Industrial connections and load for the next five years

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RESPONSE:

a) - b) EPI relied on its historical experience as well as known and anticipated developments for the purpose of establishing the Customer Connections – Residential & Subdivision, and Commercial & Industrial capital budgets outlined in the DSP. Though the cost per connection varies substantially due to site and customer-specific factors (particularly for commercial and industrial connections), EPI cross-referenced its capital forecast against the outputs of the load and customer forecast described in Exhibit 3 in order to assess reasonability. A comparison of the as-filed capital budgets and the actual and forecast new customers outlined in the updated load forecast (EPI_2026_CoS_Load_Forecast_Model_IRR_20251126) demonstrates EPI was conservative in establishing the capital budget required to connect new customers, given that both residential and commercial/industrial 2026 budgeted $/customer addition are below the average of 2021 to 2024 actuals. Please see Tables 1 and 2 below.

Table 1: Average $/Residential Customer Addition 2021 - 2026

	Actual					Forecast	
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Customer Connections - Residential & Subdivisions ($ millions)[1]		$2.89	$5.92	$2.74	$1.56	$1.80	$1.90
Year-End Residential Customer Count[2]	54,315	55,226	56,078	56,526	57,068	57,259	57,981
Residential Customer Additions		911	852	448	542	191	722
$000's/Residential Customer Addition		**$3.18**	**$6.95**	**$6.11**	**$2.87**	**$9.44**	**$2.63**
	Average: 2021-2024 Actuals ($000's)						**$4.78**

[1] Exhibit 2, Distribution System Plan, page 140, Table 5-3.
[2] Consistent with load forecast customer count. Load forecast customer count presents average annual customers as opposed to Year-End Customer Count presented in Table 1.

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Table 2: Average $/Commercial & Industrial Customer Addition 2021 - 2026

	Actual					Forecast	
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Customer Connections - Commercial & Industrial[3]		$1.62	$2.03	$1.85	$1.76	$1.40	$1.44
Year-End GS<50 & GS>50 Customer Count[4]	6,270	6,279	6,360	6,382	6,411	6,443	6,477
GS Customer Additions		9	81	22	29	32	34
$000's/GS Customer Addition		**$180.22**	**$25.00**	**$83.86**	**$60.55**	**$43.79**	**$42.16**
	Average: 2021-2024 Actuals ($000's)						**$87.41**

[3] Exhibit 2, Distribution System Plan, page 140, Table 5-3.
[4] Consistent with load forecast customer count. Load forecast customer count presents average annual customers as opposed to Year-End Customer Count presented in Table 1.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -6

Reference: Exhibit 2, pages 11- Section 2.1.5, Appendix 2-AA

a) What accounts for the large increase in the cost of transformer replacements in 2024 (line 31)?

RESPONSE:

a) Please see Exhibit 2, Attachment 2-C, DSP Table 5-19: 2024 System Renewal Projects and Section 3.1.2 and Table 3-13 (including the paragraphs immediately below the table).

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -7

Reference: Exhibit 2, Attachment C, DSP Part 1, pages 63-

a) Please provide Tables 3-25, 3-26 and 3-27 by rate zones.
b) Does EPI gather data on response time to it various non-contiguous are areas? If yes, please provide these metrics. If not how does EPI understand whether it is providing similar reliability to its different service areas.

RESPONSE:

a) Please see Tables 3-25, 3-26, and 3-27 by rate zone.

Table 3-25: Number of Interruptions by Cause Code (Excluding MEDs) - MAIN								
Line No.	Cause Code	2020	2021	2022	2023	2024	Total Outages	Percentage Share
1	Unknown	25	8	9	17	19	78	3.90%
2	Scheduled	49	168	161	162	165	705	35.27%
3	Loss of Supply	35	53	72	62	81	303	15.16%
4	Tree Contacts	35	28	17	10	7	97	4.85%
5	Lightning	13	8	8	7	3	39	1.95%
6	Defective Equipment	107	85	83	75	83	433	21.66%
7	Adverse Weather	5	6	15	28	4	58	2.90%
8	Adverse Environment	2	1	9	0	0	12	0.60%
9	Human Element	3	6	2	5	3	19	0.95%
10	Foreign Interference	45	54	50	39	67	255	12.76%
11	**Total**	**319**	**417**	**426**	**405**	**432**	**1,999**	**100.00%**

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Table 3-25: Number of Interruptions by Cause Code (Excluding MEDs) - ST. THOMAS

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Outages	Percentage Share
1	Unknown	0	3	2	3	5	13	3.57%
2	Scheduled	13	31	38	48	72	202	55.49%
3	Loss of Supply	2	1	1	0	2	6	1.65%
4	Tree Contacts	7	5	2	2	2	18	4.95%
5	Lightning	1	0	0	0	3	4	1.10%
6	Defective Equipment	13	8	11	20	18	70	19.23%
7	Adverse Weather	1	1	1	1	0	4	1.10%
8	Adverse Environment	0	0	0	0	0	0	0.00%
9	Human Element	0	0	0	0	0	0	0.00%
10	Foreign Interference	3	9	8	8	19	47	12.91%
11	**Total**	**40**	**58**	**63**	**82**	**121**	**364**	**100.00%**

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Table 3-26: Number of Customer Interruptions by Cause Code (Excluding MEDs) - MAIN

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Custome	Percentage Share
1	Unknown	8,644	526	3,151	989	6,822	20,132	3.60%
2	Scheduled	2,754	6,744	4,402	6,920	3,516	24,336	4.35%
3	Loss of Supply	22,687	61,125	74,814	53,943	61,082	273,651	48.94%
4	Tree Contacts	5,046	10,855	6,674	3,951	1,539	28,065	5.02%
5	Lightning	12,504	3,530	6,536	4,035	796	27,401	4.90%
6	Defective Equipment	22,944	14,403	21,541	23,721	21,633	104,242	18.64%
7	Adverse Weather	203	1,800	9,157	2,349	234	13,743	2.46%
8	Adverse Environment	21	7	3,824	0	0	3,852	0.69%
9	Human Element	5	11,379	740	4,096	5,125	21,345	3.82%
10	Foreign Interference	3,325	4,322	5,230	6,923	22,629	42,429	7.59%
11	**Total**	**78,133**	**114,691**	**136,069**	**106,927**	**123,376**	**559,196**	**100.00%**

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Table 3-26: Number of Customer Interruptions by Cause Code (Excluding MEDs) - ST. THOMAS

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Custome	Percentage Share
1	Unknown	0	3,153	15	49	128	3,345	2.78%
2	Scheduled	201	1,186	972	1,400	1,061	4,820	4.01%
3	Loss of Supply	11,742	78	19,000	0	13,825	44,645	37.15%
4	Tree Contacts	5,742	1,134	131	135	8,207	15,349	12.77%
5	Lightning	9	0	0	0	181	190	0.16%
6	Defective Equipment	10,278	144	6,713	3,881	6,521	27,537	22.91%
7	Adverse Weather	17	3,763	42	37	0	3,859	3.21%
8	Adverse Environment	0	0	0	0	0	0	0.00%
9	Human Element	0	0	0	0	0	0	0.00%
10	Foreign Interference	47	135	4,496	505	15,246	20,429	17.00%
11	**Total**	**28,036**	**9,593**	**31,369**	**6,007**	**45,169**	**120,174**	**100.00%**

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Table 3-27: Number of Customer Hours of Interruption by Cause Code (Excluding MEDs) - MAIN

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Outages	Percentage Share
1	Unknown	7,293	459	227	988	3,187	12,154	1.70%
2	Scheduled	5,906	9,784	6,943	13,762	3,665	40,060	5.60%
3	Loss of Supply	43,955	109,476	74,414	71,261	71,443	370,550	51.82%
4	Tree Contacts	11,414	8,030	17,843	3,850	1,959	43,096	6.03%
5	Lightning	10,332	3,599	16,922	4,849	1,277	36,979	5.17%
6	Defective Equipment	22,218	19,436	22,377	33,589	20,181	117,801	16.48%
7	Adverse Weather	954	8,177	25,668	3,794	298	38,890	5.44%
8	Adverse Environment	133	1	4,710	0	0	4,843	0.68%
9	Human Element	9	3,752	437	265	639	5,102	0.71%
10	Foreign Interference	3,835	9,323	6,690	14,459	11,243	45,549	6.37%
11	**Total**	**106,047**	**172,037**	**176,232**	**146,816**	**113,892**	**715,025**	**100.00%**

Table 3-27: Number of Customer Hours of Interruption by Cause Code (Excluding MEDs) - ST. THOMAS

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Outages	Percentage Share
1	Unknown	0	793	29	28	237	1,087	0.89%
2	Scheduled	609	3,045	1,827	1,763	1,062	8,306	6.82%
3	Loss of Supply	1,673	249	30,891	0	4,194	37,006	30.39%
4	Tree Contacts	18,797	401	539	132	16,496	36,365	29.87%
5	Lightning	21	0	0	0	306	327	0.27%
6	Defective Equipment	7,823	147	3,201	4,773	9,799	25,744	21.14%
7	Adverse Weather	35	69	95	269	0	468	0.38%
8	Adverse Environment	0	0	0	0	0	0	0.00%
9	Human Element	0	0	0	0	0	0	0.00%
10	Foreign Interference	74	174	2,607	601	8,993	12,448	10.22%
11	**Total**	**29,031**	**4,878**	**39,189**	**7,565**	**41,087**	**121,750**	**100.00%**

b) EPI does not directly gather data on response time to the 17 communities it serves. EPI monitors its system by utilizing Worst Performing Feeder analysis (as described in Exhibit 2, Attachment 2-C DSP, Section 3.3.1.1.4) to identify those feeders that are experiencing sustained interruptions and conduct targeted investment remediations.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -8

Reference: Tab Exhibit 2, Attachment 2-C DSP Part 6 of 6, Attachment J,
9. Metering Renewal

"Approximately an additional 65% of EPI meters will need to be resealed during the forecast window."

a) Given 65% of meters are being resealed does this mean that a maximum of 45% of meters are being replaced with AMI 2.0 capable meters?
b) Please provide the implementation plan which outlines the AMI communication and other AMI 2.0 infrastructure investments over the DSP plan period.
c) This projected is noted as starting in 2026. In the three years prior EPI has been spending in excess of $1.4 on "metering renewal" (Appendix 2-AA) please clarify the difference between the investments of the last three years (ending 2025)
and what is being done in 2026 onward at an incremental cost of approximately $1 - $1.5 million per year. Specifically address if (when) the meter replacement technology has changed.

RESPONSE:

a) No. As noted in Exhibit 2, Attachment 2-C DSP, Section 4.3.3.1, approximately 65% of EPI's fleet of smart meters will have reached the end of their first or second re-seal period as specified by Measurement Canada (through the forecast period). Some resealing will occur and approximately 30% of the EPI smart meter fleet will be replaced with AMI 2.0 capable meters in the forecast period.
b) Please see the response at 2-Staff-17 (a)-(c).
c) As noted in Exhibit 2, Attachment 2-C DSP, Section 3.1.2.2, EPI was an approved early adopter of smart meters and originally commenced installing its smart meter fleet in 2006-2007 as a result of a provincial mandate. Many of these meters reached their typical lifespan

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during the Historical Period and meters have began testing poorly during the Measurement Canada sampling process. Accordingly, increased Metering Renewal investment in the Historical Period is consistent with compliance replacements due to meters testing poorly, as well as inflationary cost increases. EPI introduced modernized meter technology (AMI 2.0) starting in 2022, consistent with the deployment strategy discussed at response 2-Staff-17 (a)-(c). For 2026 and onward, large cohorts of meters deployed during the initial installation are coming due for replacement.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -9

Reference: Exhibit 2, DSP Attachment J Material Investment Narrative,
17. Capacity

a) Please provide details on the 5 largest projects done under the Capacity Enhancements in 2025 including: budget, actual costs incurred to date, status of the project's in-service date.
b) If not included in a) please provide the same information as in a) for the Edgeware TS (St. Thomas).

RESPONSE:

a) In 2025, the only project undertaken under the Capacity Enhancements program was the Capacity Expansion project in St. Thomas. The project involves installation of a new breaker at Edgeware TS and construction of a new feeder by EPI to relieve existing capacity constraints in St. Thomas. The budget for this project was \$3.9M. Job-specific expenditures as of October 31, 2025, are \$3.8M and the new feeder was energized on November 21, 2025. Once final invoices are received from all third-party contractors, EPI expects that this project will come in on budget.
b) Please see a) above.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -10

Reference: Exhibit 2, pages 57-

a) Please provide the forecast cost of i) the HVAC enhancement and roof replacement of the Chatham facility and ii) the Materials Storage Building.

b) Please provide the current status of these two projects (separately) and clarify as to whether the Storage building is currently in use.

RESPONSE:

a) The forecast costs are as follows: HVAC Enhancement - $125k, Roof Replacement - $505k, Material Storage Building - $450k.

b) The roof replacement is complete. The electrical component of the HVAC enhancement is complete and the remaining materials are on site and the enhancement is on schedule to be completed prior to the end of December. The Materials Storage Building construction is on schedule and will be completed in early December, with materials occupancy usage in mid-December.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -11

Reference: Exhibit 2, DSP Attachment J Material Investment Narrative, 22

a) Please provide a list, by vehicle type e.g. bucket truck, service pickup, suv/car, trailers etc.) for each year 2024, 2025 and 2026 which shows the number of that type of vehicle purchased, the number retired (or expected to be retired in 2026) and the average age of the vehicles in each category in each year.

b) Does 2025 ISA (as shown in Appendix 2-BA) currently include any vehicles not yet delivered to EPI. If yes, please provide the expected delivery date.

RESPONSE:

a) Please see the table below summarizing the vehicle purchases and retirements in 2024, 2025 and 2026. The purchases shown below correspond to the in-service dates of the applicable vehicles.

Year	Vehicle Type	Total Purchased	Total Retired	Average Age of Retired Vehicle
2024	Bucket Truck	1	1	13
	Pickup Truck	3	4	11
	SUV/car	0	2	11
	Trailer	4	2	18
	Digger Derrick	0	1	21
2025	Bucket Truck	2	1	8
	Pickup Truck	3	2	9
	SUV/car	1	2	9
	Trailer	3	4	34
	Digger Derrick	1	1	15
2026	Bucket Truck	1	2	15
	Pickup Truck	4	3	10
	SUV/car	0	1	10
	Trailer	0	0	N/A
	Digger Derrick	0	0	N/A

b) No, 2025 ISA does not include any vehicles not yet delivered to EPI.

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RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2.0-VECC -12

Reference: Exhibit 2, DSP Attachment J Material Investment Narrative
14 - Voltage conversion

"During the 2026-2030 Forecast Period, EPI plans to offload 5 substations with concentrated efforts in Strathroy, Blenheim and Wheatley."

a) Please provide the name of each of the referenced 5 stations, the year in which it is expected that the project to "offload" the station is expected to begin and the year the project is expected to be completed.

b) Please also provide the current forecast cost for each project listed in a)

c) EPI is proposing a significant increase in its voltage conversion project. Please provide an estimate of the reduction in cost and a revised cost estimate for this category of costs (voltage conversion) for each year, 2026-2030 under two scenarios:

i) deferral of one station to 2031 or beyond,
ii) deferral of two stations to 2031 or beyond.

d) Please explain how EPI would assess which stations might be delayed and what risks might occur in delaying those projects.

RESPONSE:

a) Please see the table below.

Station	Conversion Start Year	Conversion / Offload Completion Year
Strathroy Sub 24	2023	2027

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Strathroy Sub 23	2024	2029
Blenheim East (BLE)	2026	2029
Strathroy Sub 21	2026	2030
Wheatley DS	2029	2030

b) Please refer to the table below detailing the forecasted expenditure to offload each station during the forecast period. Note that the amounts presented represent only the expenditures anticipated within the forecast period and exclude any costs already incurred for conversion work completed prior to this timeframe.

Station	**Total Forecasted Expenditure (2026-2030, millions)**
Strathroy Sub 24 Offloading	$2.8
Strathroy Sub 23 Offloading	$1.1
Blenheim East (BLE) Offloading	$8.2
Strathroy Sub 21 Offloading	$5.5
Wheatley DS Offloading	$4.4
Station Decommissioning	$0.4

c) EPI's spending on voltage conversion projects remains consistent, i.e. 2026 is consistent with the 2024 Historical year values, and 2026 is lower than the 2025 Bridge Year.

i) Please see the response at 2-Staff-6 part (g).

ii) Deferring the offloading of a second station (Strathroy Sub 21) to 2031 and thereby increasing the total project length from 5 year to 6 years, would result in a further reallocation of $907k across EPI's asset renewal projects. While this would result in the negative consequences from part d), it would not alter the capital spend in the 2026 Test Year. For stations located in larger communities such as St. Thomas, Chatham, Strathroy and Ridgetown, the substations work in conjunction with each other to provide backup and resiliency to the system. Deferring work on one will result in a correlated delay in being able to decommission/offload other stations

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within the community.

d) Deferring investment in EPI's voltage conversion and station offloading programs would have material negative consequences for customers, assets, and long-term system performance. Timely investment is necessary to maintain reliability, safety, and efficiency as further described below:

1. Customer Consultation: Clear Support for Sustained Investment

In the 2021–2025 DSP, customers explicitly endorsed a *"faster pace scenario for Voltage Conversion,"* leading EPI to increase planned substation decommissionings from four to five and to accelerate conversion of low-voltage cable.

As discussed in Exhibit 1, Section 1.7.3, Phases One and Two of customer engagement reaffirmed that customers support investments required to maintain reliability and modernize aging infrastructure, even if this increases costs. Deferring conversion would therefore conflict with long running expressed customer preferences for proactive renewal and timely modernization.

2. Restriction on Renewable and DER Connections

Feeder and station capacity limitations already constrain new renewable energy connections. Voltage conversion and feeder offloading are prerequisites to release capacity and accommodate future renewable and DERs as 10 of EPI's 11 restricted feeders are on its 4kV network. Deferral would delay customer access to renewable generation to meet the IESO's forecasted demand and energy growth.

3. Restriction on Additional Load Capacity

In addition to restricting the connections of DERs, EPI's low voltage stations have relatively low capacities – the largest remaining in service transformer has a capacity of only 5 MVA, with many in the 3 MVA range. The feeders supplied by these stations have their capacities restricted even further due to the available voltage and construction. Enabling customers to access additional capacity to support electrification requires supplying these customers from the 27.6 kV network.

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4. Loss of Smart-Grid and Automation Benefits

Smart reclosers, switches, and automation investments depend on converted 27.6 kV feeders to deliver full functionality. Deferral prevents implementation of self-healing, automatic restoration, and advanced control features, prolonging outage duration and limiting system flexibility.

5. Misalignment with Asset-Condition Priorities

The 2024 Asset Condition Assessment identifies multiple asset classes in *"Very Poor"* condition, including poles, cables, and switches. Conversion sequencing aligns directly with these deteriorated feeders; deferral would delay renewal where risk is greatest and reduce overall investment efficiency.

6. Increased Risk of Forced Station Rebuilds

Many 4 kV substations and related equipment are at end-of-life. Even for assets in otherwise acceptable condition, availability of parts and expertise to sustain them becomes a limiting factor in how long they can remain in service. Without timely offloading, station sustainment eventually reached a point where it cannot continue without major reinvestment, increasing the likelihood of forced and costly rebuilds to maintain reliability. Planned conversion is significantly more cost-effective than emergency rebuilds of a system that no longer fully meets the needs of EPI's customers.

7. Cascading Delays in Station Decommissioning

Substation decommissioning depends on completion of feeder conversion.
Deferral delays station retirements, prolonging reliance on obsolete assets and increasing operational strain on remaining stations.

8. Prolonged Higher System Losses

Conversion to 27.6 kV is the primary strategy to reduce losses; delaying it prolongs both energy waste and costs to customers.

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