Date Filed: October 09, 2026

Witness: David L. Gladey and Steven Lamontagne
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-ADDITIONS-1 at p 13. Please provide the results of the condition assessments described in the Planning Process section for distribution poles, overhead conductor, underground cable, network equipment and substation transformers, showing units inspected, units assessed as deficient, units replaced, and units carried forward.

Response:

Distribution pole replacements are driven by The Company's inspection and assessment program. Poles are inspected and evaluated based on an inspection cycle and assets identified as deficient through the inspection process are replaced. For overhead conductor, underground cable, and network equipment programs, The Company does not perform condition assessments that produce a discrete population of assets inspected, found deficient and replaced. Instead, these replacement programs are based on defined populations of assets that are evaluated and prioritized using risk-based asset management methodologies. Substation transformers are evaluated based on an asset health score (please refer to OCC-596)[i].

- Distribution Poles.

Connecticut's electric distribution pole system was largely designed and constructed under historical engineering standards that reflected the environmental conditions, loading assumptions, and vegetation characteristics existing at the time of installation. Since then, changes in weather patterns, increased storm intensity, aging vegetation, and evolving reliability and resiliency requirements have materially altered the operating environment in which these assets must perform.

As wood utility poles age beyond their expected service life, they enter the wear-out phase of the asset life cycle, during which the probability of failure increases due to factors such as decay, deterioration, physical damage, and loss of structural capacity. Under normal operating conditions and with proper maintenance, roadside wood utility poles are generally expected to remain in service for approximately 40 to 45 years. However, the average age of Connecticut's roadside pole population is currently approximately 47 years. For poles located within Rights-of-Way ("ROW"), the average age is approximately 50 years. Many of these assets exhibit visible signs of

deterioration, including pole and crossarm degradation, as well as damage caused by wildlife activity and environmental exposure.

The aging condition of the ROW pole population, when combined with changing weather patterns and increasingly mature tree canopy conditions, heightens the risk of pole failures during wind, snow, ice, and other severe weather events. This risk is further elevated where existing assets were constructed to historical design standards that do not reflect current reliability and resiliency expectations.

Wood utility poles are categorized according to a nationally recognized classification system based on strength and height. Under this system, Class 1 poles provide the greatest structural capacity, while higher numerical classes represent progressively smaller and less robust poles. Consistent with current engineering requirements, the Company's present construction standard requires, at a minimum, the installation of Class 2 poles for new facilities. This standard reflects the need to accommodate taller and stronger overhead configurations capable of withstanding modern loading conditions associated with storms, vegetation contact, and system reliability requirements.

Approximately 39% of existing distribution poles do not meet The Company’s current minimum pole class standard. These poles possess materially less structural capacity and height than contemporary design requirements contemplate. As a result, a substantial portion of the existing pole fleet was installed under prior engineering standards and may not be capable of supporting current loading conditions associated with modern conductor configurations, vegetation impacts, and severe weather events without increased risk of failure.

Recognizing the importance of proactively managing this aging infrastructure, the Company reviewed its pole inspection practices in 2025 and adopted a revised inspection cycle that reduces the interval between inspections from 15 to 10 years. The enhanced inspection program is intended to identify deterioration and structural deficiencies earlier in the asset life cycle, thereby enabling more timely corrective action and reducing the likelihood of in-service failures. Beginning in 2026, the Company expects to inspect approximately 41,000 to 42,500 custodial poles annually under the revised inspection schedule.

The number of poles requiring replacement each year is driven by the results of the inspection program and the number of assets identified as failed or deficient. Poles designated as "rejects" are removed from service because their remaining structural capacity has deteriorated below 67 percent of original strength or because they have sustained mechanical damage that precludes their continued safe and reliable operation. Such poles cannot remain in service and must be replaced

to maintain public safety, system reliability, and compliance with applicable engineering standards.

Given the age, condition, and structural characteristics of the existing pole population, replacement of the pole fleet to current design standards represents a long-term asset management initiative requiring systematic, risk-based investment. Through a prioritized replacement strategy focused on the highest-risk assets, the Company seeks to improve system reliability, enhance storm resiliency, reduce failure risk, and ensure that the distribution system is capable of meeting present and future operational requirements.

- Overhead Conductor,

The Company's distribution system consists of approximately 16,640 circuit miles of overhead primary construction consisting of bare wire and covered wire. Primary distribution voltages range from 4.16kV to 34.5kV with the majority of circuits operating at 4.8kV, 13.2kV, 13.8kV and 23kV.

These statistics indicate that there are approximately 7,577 miles or 47 percent bare wire, and approximately 9,140 miles, or 53 percent covered wire miles that includes aerial and spacer cable. Further, the statistics indicates that bare cooper wire, run through and under some of the most mature, densely forested corridors of any utility in the United States. Approximately 85 percent of the state's trees are over 61 years old, tall and heavily canopied, with many growing directly into or over utility lines.

When storms arrive, these are the trees that fall first and most often directly onto distribution lines. This wire has no protection against tree contact. When a branch or limb touches bare wire, it creates an immediate fault, which means at least a momentary interruption for all customers downstream. The vegetation operating environment and the increase of wind events and storms combined with the high proportion of bare overhead distribution circuits, is at the core of any real or perceived reliability and resiliency performance issues on the Connecticut distribution system.

The Company in support of its capital investment decision to improve electric distribution reliability is using both historic performance and forward-looking analytics, and is proposing to reconductor approximately 3,774 miles of its #2, #4, and #6 bare copper conductor because it has exceeded its expected service life, typically 50 years, and has experienced significant mechanical degradation, including embrittlement and reduced tensile strength. These aging conductors exhibit elevated failure rates under normal loading, environmental stress conditions and contribute to an increased number of failure events during inclement weather that are directly associated with bare Cu conductors.

Under the Targeted System Performance, the Company will prioritize lateral zones with the highest asset-related failure risk using data driven and Customer Minutes Interrupted (CMI) over a four-year evaluation period and $/CMI saved. Data-driven prioritization ensures that efforts target zones where replacement yields the greatest reliability improvement and mitigation of repetitive outages. The Company has identified this area at exhibit CLP-TSP-3 page 38. The Company has requested baseline funding of $16M per year to prioritize the areas with bare cooper conductors and replace them with stronger cover conductors- tree wire.

- Underground cable and PILC

The Company's Underground distribution system consists of approximately 6,997 circuit miles of underground primary construction, including both direct-buried and underground duct and manhole primary construction. Urban centers such as Hartford, Waterbury, Norwalk and Stamford are served primarily by underground cable and interconnected network systems. Although these systems are largely immune to weather and tree events, each system presents its own challenges.

When underground cables fail, locating and repairing the fault takes much longer than an overhead repair, often resulting in outage durations of many hours to days. A second cable failure during abnormal operating conditions could result in the loss of an entire network, affecting a large number of customers. Paper-insulated lead-covered (PILC) cable, a legacy underground cable type, is approaching end of life in many locations. These older cables, which now have higher failure rates, must be proactively replaced to prevent manhole events, manhole fires, and worker safety incidents.

PILC cables were widely installed through 1984, primarily on circuit getaways and in networked underground systems. The designed service life of approximately 40–50 years; many remaining cables have exceeded their expected life. Aging PILC cables experience roughly 1 failure per 20 miles once they are over 45-year-old.

Rather than waiting for failures to occur which in underground systems can mean extended outages, manhole events, and serious worker safety risks, the Company is taking a proactive approach to replace and prioritize replacement of PILC cable, which now have higher failure rates to prevent manhole events, manhole fires, and worker safety incidents.

Approximately 270 miles of PILC cable remain on more than 200 feeders in Connecticut. Under the Targeted System Performance ("TSP") plan, the Company will prioritize replacement of PILC based on circuit load, number of reliability events, customers at risk and number of customers impacted. The Company is proposing a current baseline of $11 million/year resulting in a 25-year replacement program or 17 years with ~$5.5M of incremental funding per year.

- Direct Buried ("DB") Cable replacement

This program targets the replacement of direct buried distribution cables in underground residential and commercial developments that are reaching the end of their useful lives. It has been determined on an industry-wide basis that much of the original Cross-Linked Polyethylene ("XLP") and High Melting Point ("HMP")-insulated primary cable installed in the DB system has not achieved its engineered life expectancy. The Eversource distribution system encompasses a substantial component of DB cable which was installed in the 1970s and 1980s. At that time, the installation of the cable did not include any conduit. The current standard places all below-grade cable in conduit and/or duct system to prevent degradation.

There are approximately 5,347 circuit miles of UG Primary Direct Buried in Connecticut. To provide a perspective, baseline funding of $28.4M yields a 200-year completion timeline in all towns in CT.

- Network Equipment

Underground Network Automation projects support the replacement of aging distribution switch gear, provide quicker restoration, telemetry, and improved safety.

The replacement of switchgear that has reached end-of-life proactively prior to failure would reduce both customer outages and prevent abnormal system configurations. Switchgear replacement will enable the electrical system to be switched remotely and allow for the operators to see real time load data, which will improve the outage restoration times by not having to dispatch a crew to manually operate the gear.

The newly installed switchgear is dead-front constructed (use of elbows vs bolted on connections) and provides the crews safer ways to switch customers, reducing potential injuries while improving restoration times.

The replacement program is prioritized based on customers at risk and equipment conditions. Baseline funding of ~$3.5M per 9 years would result in a 41-year replacement program or 18 years with ~$4.6M of 10 incremental funding per year.

- For Substation Transformers please refer to OCC-596.

The Company performs maintenance of its distribution system on a continuing scheduled basis. Please refer to Table 1, for all the list of activities outlined in the plan.

TABLE 1.

The Connecticut Light and Power Company Inspection and Maintenance System Report									
January 1 Through December 31, 2025									
System Report						Number of scheduled and completed			
Ref. No	I&M Program Description	Group Responsible	Procedure Number	Unit Description	Total Number of Units	Scheduled for 2025	Completed by 12/31/25	% completed by 12/31/25	Notes
1	DB Facilities	Operations	EMP 5.11 EMP 6.11	Switch/Transformer	72,633	1,176	1,137	97%	1
2	Capacitor Banks	Maintenance	EMP 5.05 EMP 6.05	Capacitor Bank	1,745	1,745	1,745	100%	3
3	Automatic Voltage Regulators	Maintenance	EMP 5.01 EMP 6.01	Regulator	964	306	306	100%	3
4	Reclosers	Maintenance	EMP 5.44 - Inspections	Recloser	3,958	968	968	100%	2, 3
5	UG System Network Transformers	Maintenance	EMP 5.29, EMP 5.30- Routine Inspection	Transformer/Protector	818	666 (I)	666	100%	3,7
			EMP 5.29 EMP 5.30 Major Maintenance			152 (M)	152	100%	3, 7
6	UG Plant	Operations	EMP 5.59	UG Structure (Manholes & Vaults)	10,792	1,486	1,472	99%	4, 6
7	Street Lights	Operations	EMP 5.48	Pole/Fixture	4,016	2,712	2,712	100%	
8	Infrared Inspection	Maintenance	EMP 5.22	Circuit	1,017	1,017	1,017	100%	

Prior Referenced Response:

[i] OCC-596 Question:

Refer to Exhibit CLP-TSP-1 at 55, "…plan to maintain a transformer fleet that does not exceed 70 years of age." Identify every law, regulation, manufacturer requirement, or mandatory engineering standard that requires a substation transformer to be retired at 40 years, 70 years, or any other specified age. If no such requirement exists, please confirm.

a. Provide all existing studies, analyses, and historical data relied upon by the Company to conclude that transformer failure risk increases rapidly as transformers approach or exceed 70 years of age. If the Company has not performed an empirical analysis using its transformer-failure experience, please justify.
b. Provide the Company data and analyses used to establish the transformer age thresholds or replacement criteria in the TSP, including the stated 40-year useful life and increased failure risk near 70 years. Include the age and cause of failure for each Company transformer that failed during the period covered by the analysis. If the criteria are not based on the Company's actual failure experience, identify the source on which they are based.

OCC-596 Response

There are no laws, regulations, manufacturer requirements, or mandatory engineering standards that require substation transformers to be retired at a specific age. The age of a power transformer is one of the most important factors in assessing asset condition. Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average expected life for an individual transformer is approximately 40 years according to industry consortiums, and

manufacturers. International reliability surveys (i.e., CIGRE) report major failure rates on the order of ~0.3% per transformer-year across large populations, with failure behavior influenced by aging and asset condition. Industry asset-management guidance supports risk-based decision-making that balances failure risk and cost.

Eversource employs several methods to both actively and passively monitor the health of distribution power transformers within its service area. Active and continuous monitoring methods include out of specification alarming. Alarms may include indications for bushing monitoring (if applicable), LTC trouble, dissolved gas (if applicable), oil level alarms, and oil temperature alarms, among others.

This information along with periodic maintenance and testing reports provide data into Eversource's condition-based asset management methodology that draws on multiple sources including:

• Transformer nameplate characteristics
• Oil quality and DGA trends
• Abnormal thermal, electrical, or core indicators derived from PTX health modeling
• Maintenance and inspection records
• Power Factor Testing

Eversource utilizes a detailed asset health score generated through the Electric Power Research Institute (EPRI) PTX tool to assess power transformer asset health. OCC-596, Attachment 4 CONFIDENTIAL, is a technical guide to the EPRI Power Transformer Expert System (PTX). The PTX tool evaluates normal degradation, abnormal operating conditions, oil quality, and age to produce two critical indicators: the Long-Term Health Index (LTI) and the Short-Term Health Index (STI). The PTX health index is measured in the range of 0 to 1, with 0 meaning healthy and 1 needing immediate replacement. A value greater than 0.5 is considered poor health, such that if repair/replacement is not performed the transformer will continue to decline leading to equipment failure.

Eversource has 27 transformers in CT, or about 8.6% of the fleet, that fall within the range considered to be in poor condition. This means that without repair or replacement, their condition is expected to continue declining, increasing the risk of equipment failure. As a result, Eversource continues to prioritize and initiate replacement projects for these transformers.

Attachments included note that multiple industry sources discuss aging and failure rates of substation power transformers.

- OCC-596, Attachment 1 CONFIDENTIAL, A2 Cigre Brochure 939 AC Transformer Reliability
- OCC-596, Attachment 2 CONFIDENTIAL, 1013566 Plant Support Engineering Large Transformer End of Expected Life Considerations and the Need for Planning
- OCC-596, Attachment 3, EXEC-2022-001242 - Large Power Transformer Resilience Report 7-10-24
- OCC-596, Attachment 4 CONFIDENTIAL, 3002026877_Power Transformer Expert System (PTX) Software Application Guide_ Introduction to PTX, Overview, Technical Basis and Application Information

Based on industry experience, while transformers can operate beyond their typical design life of 40 years, the risk of failure exponentially increases after 70 years of service life, due to paper insulation degradation. OCC-596, Attachment 1 CONFIDENTIAL, a CIGRE study from 2024, shows the failure rate of transformers has a noticeable increase starting at 40 years and exponentially increases as the asset exceeds 65 years old. This study reviewed analysis of thousands of transformers including many voltage classes from around the world to build depth into the data available. OCC-596, Attachment 2 CONFIDENTIAL is an EPRI paper discussing "Large Transformer End-of-Expected Life" which notes "the useful life of a large, oil-filled transformer is between 30 and 40 years with insulation

or bus supports being the most likely to fail due to age. For the insulation, thermal aging of the paper insulation is the likely cause of failure."

OCC-596, Attachment 3, is a Department of Energy report from 2024, citing that large power transformers "are typically considered to have a design lifetime on the order of 40 years. In 2014, a DOE report estimated that the average age of LPTs in the North American grid was 38–40 years, indicating that a substantial fraction of those LPTs are at or over that design lifetime. These LPTs will ultimately need to be replaced or refurbished." These industry research groups and others have provided basis within their published studies to support the concerns of failure with any transformer over 40 years in-service.

As a result, Eversource's Asset Health philosophy for transformers is to operate transformers to their maximum useful life, but plan to maintain a transformer fleet that does not exceed 70 years of age and an average age of approximately 35 years. The objective is to find the balance between affordability and preventing an aged transformer fleet that approaches the "knee of the curve" which results in failure rates that increase significantly. With a large portion of the transformer fleet being between 50 and 80 years old, as these transformers continue to approach and exceed 70 years, the rate of failure will increase rapidly. Due to the complexity and time duration of procuring and replacing transformers, a significant increase in failures would result in the inability to maintain reliability by reactively replacing an increased volume of transformer failures.

The six most recent failures of transformers in CT were all attributed to internal failures of the transformer. The ages of the failed transformers were 32, 50, 52, 52, 56, and 83 years old at the time of the failure.