Date Filed: September 28, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 49. Provide the complete NWA study for every traditional capacity project included in the 2027-2031 plan, including the screening date, need profile, required MW and MWh by hour, deferral period, traditional project cost and timing, avoided-cost calculation, technology assumptions, candidate resources, screening result and reason any project was excluded from further NWA evaluation.

a. For each capacity project, provide DER alternative, demand response alternative, energy efficiency alternative, battery alternative, and traditional wires alternative.

Response:

Full engineering on the substation projects identified in the 2027-2031 plan has not yet occurred because the projects are not yet at this stage of the development. The NWA analysis is part of the engineering solution selection process as the Company evaluates a range of options from "no-build;" to traditional projects; to different routing of capital investments; and to non-wires or grid enhancing technologies.

Line projects within the 2027–2031 plan have been designed in accordance with the Distribution System Planning Guide to provide safe reliable power. Projects approved after January 2025 have undergone the newly established NWA process established by PURA and have been reviewed by the process monitor and PURA, both concluding no further investigation is required. Please refer to the Non-Wires Solutions Process Cycle 1, Docket 25-08-08, Final Decision.[1]

Please refer to OCC-590, Attachment 1, Grid Needs Filing - 2025 for the list of projects submitted in January of 2025.

Please refer to OCC-590, Attachment 2, Grid Needs Filing - 2026 for the list of projects submitted in January of 2026.

[1] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/4b2aa80a45d5fe8185258d5c0051dfbf/$FILE/250808-121025.pdf

Please refer to OCC-590, Attachment 3, Grid Needs Projects Narrative Documents for projects submitted in January of 2026. Narrative documents were not required for the projects submitted in January of 2025.

Newly established projects not included in prior annual Grid Needs Filings will be submitted in the January 2027 Grid Needs Filing for NWA evaluation.

Date Filed: September 23, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 49.

a. Provide all load forecast models supporting each proposed line and substation capacity project.
b. Provide all assumptions for EV, heat pump, solar, storage, C&I load growth, data centers, step loads, and economic development load.
c. Identify any capacity projects that could be deferred by NWA, DERMS, AMI-enabled load management, or targeted demand response.
d. For each proposed capacity project, quantify the forecast overload in MVA, MW, amperes and the number of violating hours in each year.
e. For every project passing or nearly failing NWA screening, provide the full benefit-cost analysis, all sensitivities, evaluation workpapers and comparison of the NWA with load transfer, staged construction and the traditional solution. Quantify the present value of deferral for one, three, five and ten years.

Response:

a. Please refer to OCC-591, Attachment 1 CONFIDENTIAL, for a 10-year forecast for each identified substation capacity project. Long-term load forecasts are not generated at the individual feeder level. Line capacity projects are based on actual metered data versus a forecast. Feeder level forecasts become inherently less accurate as stochastic customer behavior of just a few customers can swing forecast results wildly and cause large errors, as compared to large groups where such effects average out. In addition, unlike substation investments, feeder upgrades can be done on a short turnaround time, allowing the Company to respond to actual loading on the system rather than forecasts.

b. The individual substation forecasts are located within each worksheet in OCC-591, Attachment 1 CONFIDENTIAL, and are broken into the individual categories the Company tracks.

   For details on known, firm distribution connected data centers in the Company's forecast, this would be factored into the Step Loads category. Please refer to the Company's response to information request OCC-465[i] for details on how the Company accounts for Step Loads.

C & I load growth and economic development load is aggregated into the Trend category unless they are individual requests for interconnection that are considered step loads.

Please refer to the Company's response to CLF-SC-022[ii] request on how the Company accounts for EV, heat pumps, and solar.

c. The substation capacity projects identified in the workbooks are in various stages of the project-approval process. None of the projects have reached a stage that would have received a detailed NWA analysis to date. As these projects proceed through the solution selection and engineering stages, NWA and other alternatives will be vetted. The results will be submitted during the annual grid needs filing as part of the NWS docket.

The line capacity projects identified currently exceed the planning criteria based on metered data and NWS solutions were analyzed as alternatives to traditional line projects. No existing line capacity projects could be deferred by NWA, DERMS, AMI-enabled load management, or targeted demand response. The Company submitted all capital projects to the process monitor as part of Docket No. 25-08-08 and the ongoing Docket No. 26-08-08.

d. Please refer to OCC-591, Attachment 1, for a 10-year forecast for each identified substation capacity project. Each proposed capacity project within the attachment, shows the forecast overload in MVA. The number of violating hours in each year has not yet been analyzed but this would be conducted during the NWS program process.

Forecasting is not performed at the distribution line level as these capacity projects can be executed in a short timeframe when compared to substation capacity projects. Please refer to OCC-591, Attachment 2, for the proposed line capacity projects based on actual metered data, and circuit overloads in MVA and Amps. The number of violating hours in each year is not available.

e. As part of that PURA approved process, the complete Benefit Cost Analysis (BCA) is available only after projects advance to a competitive solicitation, as the analysis relies on pricing and solution details provided by developers through the solicitation process. Without developer-specific cost information, a comprehensive BCA cannot be completed. As noted in PURA's Final Decision in Docket No. 26-08-08, no project was ordered to proceed with a competitive solicitation.

Prior Referenced Responses:

[i] OCC-465 Question:

(Economic Development Rate Rider) Please provide the anticipated capacity of data center load additions in the Company's service territory each year for the next 10 years.

a. Provide separate estimates for load requests and firm commitments.
b. Provide any analysis the Company has conducted on the extent to which the anticipated data center load impacts system costs and customer bills. Include associated workpapers in live Excel format with all formulas intact.

OCC-465 Response:

a. There are currently no active requests or firm commitments for data center load additions within the Company's distribution system.

   With regards to "Requests," while Eversource does record requests for future customer connected loads, these include significant speculative inquiries by customers, the Company does not include them in any forecasts for substation capacity needs and has not budgeted any funds in direct support of these projects until a signed workorder is in-hand and design deposits have been made. Based on the Company's historical experience many of these projects fail to materialize and, to avoid unnecessary costs and inefficiency, the Company does not dedicate or plan capacity for these projects until such time as a firm commitment is received from the customer.

   Requests or firm commitments for data center load additions within the transmission system are excluded.

b. This is not applicable as there are currently no active requests or firm commitments for data center load additions within the Company's distribution system. Such calculations are not feasible until the project specifics are known, including costs to interconnect and revenue credits -- all off which are highly dependent on a given project.

[ii] CLF-SC-022 Question:

Please provide the Company's current internal technical documentation, however titled, that describes in detail the methodology the Company uses to develop the feeder-, substation transformer-, and (if applicable) substation-level load forecasts described in the responses to CLF-SC-12 through CLF-SC-19, including, at a minimum:

c. the forecasting model or approach used (e.g., econometric/regression modeling, etc.), and how historical loads, weather data, economic or demographic inputs, and other data are incorporated;
d. how forecasted adoption of demand-side factors such as energy efficiency, distributed solar, electric vehicles, demand response, distributed energy storage, and heat pump adoption/electrification (individually or in combination) is developed and then spatially allocated down to the feeder or substation transformer level; and

e. the specific weather condition(s) or percentile(s) (e.g., a 50/50 normal or a 90/10 or 95/5 extreme weather scenario) assumed for feeder- and substation-transformer-level planning purposes.

If the Company does not maintain a single document of this kind, please provide all documents that collectively provide this information. If the Company contends that any portion of the requested document(s) is confidential or proprietary, please produce it subject to an appropriate protective order rather than withholding it, and identify the specific basis for confidentiality as to each such portion.

CLF-SC-022 Response:

a. The information requested is detailed, comprehensive data, constituting highly confidential Critical Energy Infrastructure Information ("CEII") that qualifies for protection under PURA's requirements for CEII, which protection the Company will seek when it is submitted to the record. The Company does not currently have an executed non-disclosure agreement ("NDA") in place with the Conservation Law Foundation and Sierra Club ("CLF-SC"), although the Company is in contact with CLF-SC and is appreciative for their coordination and collaboration. In addition, the Company is in the final stages of implementation of new internal information systems and document controls for enhanced cybersecurity goals that would apply to this data production. Therefore, the Company plans to supplement this response with production for all parties having executed a non-disclosure agreement with the Company, once an executed NDA is obtained from CLF-SC. In the interim the Company is submitting all non-confidential parts of the CLF-SC interrogatories.

b. The substation forecasting process begins by forecasting the peak demand at the Eversource system level for Connecticut. The Eversource system-level peak demand is forecasted using an econometric model that evaluates historical peak demand as a function of peak day weather conditions and the economy. The econometric model utilizes two different weather variables in forecasting summer peak demand, a three-day weighted temperature-humidity index and cooling degree days. The forecast assumes normal weather conditions based on the most recent 10-year period. Eversource produces a '50/50' and a '90/10' peak demand forecast. The '50/50' forecast is based on normal 10-year weather and has a 50 percent chance of being exceeded. The 90/10 forecast is the extreme weather scenario that only has a 10 percent chance of being exceeded. Moody's Analytics, an international economic consulting company, provides the economic history and forecast. Only the 90/10 peak demand forecast is relevant to and utilized by system planning.

   Once Eversource finalizes the system-level forecast, the substation level forecasts are developed. Substation forecasts are developed using panel data econometric models that evaluate substation historical peak demand as a function of the Eversource system peak demand history and forecast. The substation econometric models measure how each substation performed relative to the Eversource system and then project that relationship into the future. There are 11 different econometric models for the substation forecast for CT, determined by region and size of the substation.

   After a trend forecast is produced for each substation, the forecast is adjusted for energy efficiency, solar, electric vehicles, and large customer projects. Company sponsored energy efficiency reductions are proportionally applied to each substation based on historical peak demand. Electric vehicles and solar adjustments are assigned to specific substations based on historical trends, customer characteristics, the propensity for adoption, and their 24hour time of use profiles. Further explanations on the calculation of these out of model adjustments can be found in part b of this response. Specific, identified large

development projects or expected changes in system operations that the econometric forecasts could not otherwise predict are added to their respective substation.

Heating Forecast:
Currently, the Company's heat pump forecasts have not been released. The methodology is currently being reviewed and further refined and will be implemented in future forecast applications.

Solar Forecast:
System-level installed capacity forecasts are created by fitting a logistic curve to the Company's historical installation data, where the solar installations are categorized into residential rooftop, commercial rooftop, and commercial ground mounted/canopy based on installed capacity thresholds.

The allocation of system-level installed capacity to the station level was done in Gridtwin software, where the allocation is based on customer propensity for residential projects and project economics for commercial projects on a property by property basis (e.g. anticipated interconnection costs, incentives, etc.). The resulting station level forecast is scaled to match that of the system level forecasts.

Substation-level load is estimated by using installed capacity and station-level global horizontal irradiance (GHI) data from the SolarAnywhere API.

Using hourly irradiance data from historical summer month the Company calculates percentiles for expected irradiance of each hour for the historic global horizontal irradiance which is then applied to calculate a projected solar output at each hour of the peak day. This allows an adjustment of solar output to account for potential overcast conditions during hot and humid peak loads. Using the forecasted solar output for the peak day, the impact to the peak, at time of peak, is calculated. The same is done for the winter estimate, except only winter months are chosen.

Distributed Energy Storage Forecast:
The Company does not currently forecast distributed energy storage's impact to peak.

Energy Efficiency Forecast:
Company-sponsored EE projections are based on the most recently approved Three-Year Plan which the Company carries forward assuming stable and continuing investments into energy efficiency with comparable yields in savings, while solar projections are developed consistently with historical trends, state, and federal funding incentives. Naturally occurring EE (i.e., reduction in demand due to non-programmatic improvements in end-use efficiency) is directly captured in the trend forecast as it impacts the peaks, which in-turn informs the model.

EV Forecast:
To model such impacts as accurately as possible, the Company models electric vehicle adoption and charging through a variety of factors including consumer purchase and travel trends, existing and planned charging infrastructure, and policy. To better assess the impact of electrification in the transportation sector, the Company employs a variety of analysis methods and data sources, including:

- *System level EV adoption:* Analysis starts with historical adoption from vehicle registration. Near-term adoption forecasts are adjusted to reflect changes in state and federal policies that may accelerate or slow EV adoption. State-level decarbonization goals are used to set long-term adoption levels and inform benchmarks for the medium-term forecast trajectory.

- *Charging profiles and locations:* Using GPS tracking and mobility data, this analysis determines the flow of traffic through the state and identifies preferred regions for charging infrastructure development based on the number and length of trips terminating there, as well as the time those charging events might occur. This allows the Company to build station level specific charging profiles, as stations vary based on their customer base (i.e. daytime charging in C&I heavy substations vs evening charging at residential heavy substations). The amount and type of charging infrastructure needed to sustain the system level electric vehicle projections and likelihood of development of charging stations in certain geospatial areas are considered.
- *Charging coincidence and aggregated impacts:* While impacts of electric vehicle charging remains very high on the last mile of the system where small numbers of chargers sit behind a single asset (i.e. a pole mount transformer serving 3 houses, each with an EV, experiences a charging coincidence peak of 1), larger assets such as substations significantly benefit from coincidence factors driving down the aggregated impact. The Company utilizes mobility data to estimate the required charging duration of a vehicle arriving at a charging location and models a time series of all charging events serviced by a bulk station. This reduces the overall coincident impact of a charging location to the bulk system, depending on location, to anywhere between 1.4 kW and 2.5 kW, averaging at ~2 kW.
- *Large charge parks and hubs:* The Company tracks all large charging parks and hubs as individual out of model adjustments in its step load process. Given their singular large impact to the local system and the very likely occurring system investments based on their upgrades, the Company cannot make long-term forecasts as to when such assets transition. Step loads enter the forecast once the customer has made a commitment by opening a workorder with the Company and having made the design deposit.

c. Eversource produces a '50/50' and a '90/10' peak demand forecast. The '50/50' forecast is based on normal 10-year weather and has a 50 percent chance of being exceeded. The 90/10 forecast is the extreme weather scenario that only has a 10 percent chance of being exceeded. Only the 90/10 scenario is used to inform the Company's capacity projects.

Date Filed: September 23, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 49. State whether the Company evaluated each capacity project using historical forecast accuracy, only committed new-customer loads, and expected weather instead of 90/10 weather. For DER-driven projects, state whether historical DER completion and delay rates were considered. If such analyses were performed, provide them, including the resulting need date and project timing.

Response:

The Company does not evaluate future capacity projects based on historical forecast accuracy.

The Company uses only "firm" new customer loads in its step load modifier to the forecast. All capital projects are developed based only on those firm new customer loads in the forecast.

The term "expected weather", without further clarity of definition, is taken by the Company to mean "weather scenario that can be expected." The Company defines its 90/10 weather scenario as the highest 3-day weighted-average temperature humidity index recorded over the past 10 years. By definition therefore any 90/10 weather condition taken for the forecast by the Company has occurred once over the past decade and can therefore be expected to occur again over the next decade. The Company does not increase those weather assumptions from what was recorded over the past 10 years.

Date Filed: September 23, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 49. For each proposed capacity project, provide the annual load forecast at the affected substation and feeder level through 2040. Identify the forecast peak, applicable equipment rating, percentage of rating, forecast year of first exceedance, and all new-customer or DER projects included in the forecast. Provide the data in native, unlocked Excel format.

Response:

The Company creates a 10-year peak load forecast which, based on the most current vintage from March 2026, extends to 2035. The peak load forecast does not extend to 2040. For the annual load forecast for each capacity project, please refer to the OCC-591, Attachment 1 CONFIDENTIAL.

Date Filed: September 28, 2026

Witness: Lavelle A. Freeman and Gerhard Walker
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 49. For each proposed substation or feeder capacity project, provide the following information:

a. Traditional upgrade scope and total cost, including labor, materials, overheads, contingency, etc.
b. Study year and forecast year(s).
c. Traditional project's planned in-service date.
d. Earliest feasible NWA deployment year and the final year of the analysis period.
e. Substation, feeder and geographic location of the constraint and potential NWA.
f. For each forecast year, provide:
    i. Maximum capacity exceedance in MW;
    ii. Energy above the applicable equipment rating in MWh;
    iii. Annual increase in the exceedance in MW and MWh;
    iv. Maximum continuous duration of the exceedance in hours;
    v. Number of exceedance events and peak days;
    vi. Whether peak days are consecutive; and
    vii. Applicable normal or contingency equipment rating.
g. Identify the NWA technologies and resource mix evaluated, including the assumed percentage or capacity of battery storage, solar PV, demand response, energy efficiency and other resources.

Provide the information in native, machine-readable format, together with the hourly load forecast and applicable equipment rating used to calculate each annual MW, MWh and duration value.

Response:

Substation Capacity Projects:

a. CLP-TSP-1 at 49 refers to the capital projects in Company's Sustained Plan that are identified and will be developed to meet system needs and objectives. The specific projects related to peal load and capacity needs are listed in CLP-TSP-3 at 94-95. Presently, these projects are all at the conceptual stage and therefore are not yet at the stage where detailed engineering studies and evaluation of solutions and alternatives have been completed. Engineering scopes, cost estimates, and materials will be defined as the projects are

developed through the Eversource Capital Project Approval Process and receive project funding.

b. Please refer to OCC-591, Attachment 1. The excel worksheet contains a separate workbook with each substation forecast for the sustained performance plan.

c. The substation capacity projects identified in OCC-591, Attachment 1, do not currently have planned in-service dates as these projects are still in the conceptual stage and do not have approved scopes of work.

d. The forecast evaluation years are noted in column headers in OCC-591, Attachment 1 (2026-2035). As noted above, these projects are in the very early stage of development. As the Company evaluates and develops solutions and alternatives to meet the identified need, NWA solutions will be considered in accordance with the Company's distribution planning process in the DSPG (see CLF-SC-023, Attachment 1). A variety of solution alternatives will be developed to resolve the constraint including, but not limited to, increasing equipment ratings (e.g., using cooling techniques), transferring load, upgrading equipment, and applying non-wires solutions.

e. CLP-TSP-3 at 21-23 shows geographic location of constrained areas within the system. Substation capacity constraints that comprise the identified need are within the area served by the substation and are based on violation of substation equipment Emergency Thermal Limits during the loss of a single element within the substation fence. A typical example is the loss of the largest transformer for each voltage class within a substation.

f. Please refer to OCC-591, Attachment 1.

- For Part (i): Refer to "MVA Remaining", column (K)
- For Part (ii): Because these projects are still at the conceptual stage, this analysis has not yet been completed. However, it will be completed as part of the NWA solution development.
- For Part (iii): Because these projects are still at the conceptual stage, this analysis has not yet been completed. However, it will be completed as part of the NWA solution development.
- For Part (iv): Because these projects are still at the conceptual stage, this analysis has not yet been completed. However, it will be completed as part of the NWA solution development.

- For Part (v): Because these projects are still at the conceptual stage, this analysis has not yet been completed. However, it will be completed as part of the NWA solution development.
- For Part (vi): The Company's forecast is based on a 3-day weighted average temperature humidity index.
- For Part (vii): Refer to "LCC", column (I) and "Firm", column (L) for substation emergency rating, which is the trigger for the capacity projects in the Sustained Performance Plan.

g. The substation capacity projects identified in OCC-591 Attachment 1, do not currently have NWA solutions identified as these projects are still in early development stages. The projects will all undergo a full NW screening to determine the suitability of an NWA as a potential solution, and viable NWA solutions will be reviewed and analyzed.

Feeder Capacity Projects:

a. Please refer to OCC-594, Attachment 2 CONFIDENTIAL, Feeder Capacity Projects for traditional upgrade scope and total cost, including labor, materials, overheads, contingency, etc.

b. Please refer to OCC-594, Attachment 2 CONFIDENTIAL, for Feeder Capacity Projects for the study year. Distribution capacity projects are based on actual metered data and have been designed in accordance with the Distribution System Planning Guide to provide safe reliable power. Forecasting is not performed at the distribution line level as these capacity projects can be executed in a short timeframe when compared to substation capacity projects.

c. Please refer to OCC-594, Attachment 2 CONFIDENTIAL, for Feeder Capacity Projects for the Traditional project's planned in-service date.

d. Line projects within the 2027–2031 plan have been designed in accordance with the Distribution System Planning Guide to provide safe reliable power. Projects approved after January 2025 have undergone the newly established NWA process laid out by PURA and have been reviewed by the process monitor and PURA, both concluding no further investigation is required. Please refer to the Non-Wires Solutions Process Cycle 1, Docket 25-08-08, Final Decision.[1]

[1] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/4b2aa80a45d5fe8185258d5c0051dfbf/$FILE/250808-121025.pdf

e. Please refer to OCC-594, Attachment 2 CONFIDENTIAL, for Feeder Capacity Projects for the substation, feeder and geographic location of the constraint.

f. Forecasting is not performed at the distribution line level as these capacity projects can be executed in a short timeframe when compared to substation capacity projects. Please refer to OCC-594, Attachment 2 CONFIDENTIAL, for Feeder Capacity Projects for the following based on actual metered data:

    i. Maximum capacity exceedance in MW;

    vii. Applicable normal or contingency equipment rating

    The following data is not currently available:

    ii. Energy above the applicable equipment rating in MWh;

    iii. Annual increase in the exceedance in MW and MWh;

    iv. Maximum continuous duration of the exceedance in hours;

    v. Number of exceedance events and peak days;

    vi. Whether peak days are consecutive; and

g. Capacity NWA alternatives were evaluated with battery storage.

Date Filed: September 23, 2026

Witness: John P. DiPaola-Tromba
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 55. Confirm whether the proposed bulk transformer replacements are proactive replacements rather than replacements of failed transformers. If not confirmed, identify each replacement that is required because of an existing failure, capacity constraint, or mandatory compliance requirement.

Response:

Exhibit CLP-TSP-1 beginning at page 55, discusses the Targeted System Plan including an average of eight bulk and distribution transformers with an investment of ~$78M per year. These transformers are discussed below.

The transformers included in the plan within this investment category are proactive replacements of units over 50 years old with asset health concerns. 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 Stevenson 14A Transformer Replacement project is an ongoing project included in the Targeted System Plan related to the failure of the 14A-1X transformer at the Stevenson 14A substation. There are no other projects included in the Targeted System Plan that are a replacement of a failed transformer.

The transformer projects identified for replacement because of an existing capacity constraint are included in the Substation Capacity/System Planning investment category.

Date Filed: September 23, 2026

Witness: John P. DiPaola-Tromba
Request from: Office of Consumer Counsel

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.

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.

Date Filed: September 23, 2026

Witness: John P. DiPaola-Tromba
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-1 at 55. For each proposed proactive replacement, identify whether the Company evaluated continued operation through enhanced inspection, testing, monitoring, maintenance, refurbishment, loading limits, load transfer, or use of a spare transformer. Provide each existing analysis and state whether it found that replacement could be deferred by one, three, or five years. If no deferral or life-extension or alternate analysis was performed, please confirm the reason.

Response:

Eversource employs several methods to both actively and passively monitor the health of all power transformers within its service area. Active and continuous monitoring methods include out-of-specification alarming. Remote alarming (if applicable) is conducted through the Eversource SCADA system with alarms existing for bushing monitoring, LTC trouble, dissolved gas, oil level alarms, and oil temperature alarms, among others. Per industry best practices, local alarming is performed through panel indication lamps with corresponding nameplate alarm descriptions and annunciation technologies such as bulb annunciators and Human Machine Interfaces (HMI's).

The preventive maintenance procedures for power transformers are documented within the Eversource Maintenance Program (EMP) 5.58 Station Transformers and Oil-Filled Shunt Reactors. The inspection and maintenance tasks are catalogued into three (3) categories which include a list of asset conditions for real-time condition monitoring, time-based regular inspections, and condition-based maintenance activities. These are described in more detail below:

Condition Monitoring: Various parameters related to power transformer health are actively monitored as applicable. The monitoring is performed both locally and remotely with local monitoring performed by individual equipment alarms and station annunciators. Remote monitoring is performed via Supervisory Control and Data Acquisition (SCADA) to enable real-time asset parameter output and SCADA equipment alarms. Such parameters include temperature, oil level, pressure, and load tap changer (LTC) status.

Time-Directed Maintenance and Inspections: Eversource has established multiple routine maintenance activities required to be performed for all power transformers within specific time intervals. These activities include monthly visual inspections, annual oil sampling including dissolved gas analysis (DGA), thermographic readings, LTC maintenance, and major maintenance

activities. Major maintenance activities include power factor testing, bushing testing, excitation testing, confirmation of proper operation and integrity of pressure relief devices and ensuring all alarms operate properly.

Condition-Based Maintenance: These activities are on an as-needed basis when identified upon visual inspection, when performing time-directed maintenance activities, and when output from condition monitoring devices indicate outside normal operating values. Such activities include, but are not limited to, acoustic measurements, core grounding tests, leak repairs, and chassis repair.

Substation Technical Engineering leverages data collected by the CASCADE, PTX Analysis, and substation equipment databases to perform asset condition assessments of power transformers. The reports are based on the following six (6) parameters with recommendations for replacement by the Substation Technical Engineering team being based upon whether two (2) of the following (6) parameters are considered high risk:

- Oil Analysis Results
  - DGA
  - Fluid Quality Analysis
  - Furan Analysis on Main Tanks
- Age
- Loading
- Maintenance History
- Historical Test Data
- Physical Inspection Findings

The above practices are applicable to all power transformers. Asset age and condition will prompt enhanced inspection, testing, monitoring, and maintenance as noted in the EMP toward the goal of maximizing the usable life of a transformer.

Historically the Company has effectively maximized the life of Transformers by extensive maintenance and monitoring practices, evidenced by the age demographics of the fleet which far exceed the typical design life of 40 years. While this practice continues, the risk profile of an aging fleet compounded by longer lead times and more challenging outage constraints has resulted in a need to initiate planned replacements, beyond the historical average of 1-2 transformer replacements per year, to minimize overall impact of a failed transformer and maximize efficiency. A typical transformer replacement can take from 2 to 5 years to plan and execute. From the time of identification of deteriorating health, the transformer will continue to degrade over the course of the project execution time period. While spares are an effective mitigation plan for emergent failures, it is not a “one-size fits all” long-term mitigation plan to address the fleet risk because depending on when the failure or urgent replacements occur, it may happen at a high-risk period of the year which cannot be controlled exposing the system and customers to a much higher risk. Allowing transformers to run to failure also poses a serious safety risk to both the public and utility

workers. Additionally a failed transformer could cause damage to adjacent healthy equipment compounding the negative impact.

Prior to initiation of a transformer replacement project, the various subject matter experts (SMEs) will confer and review the nameplate data, maintenance records, and PTX scores of the unit. If a transformer is reviewed and a capital project is not to be initiated, the transformer is typically recommended to have further evaluation for maintenance mitigation of the found issue. This may include repairs or minor refurbishment actions that enable the power transformer to be reenergized and placed back in-service.

If the transformer is identified as requiring a capital project an initial funding is established and a project team assembled. The project team includes various SMEs and they are required to review the technical and financial feasibility of transformer replacement, transformer refurbishment, load transfer options, and usage of existing spare transformer inventory for a replacement. After the feasible options are developed, the project team will proceed with a formal review of the multiple feasible options within the procedures of the Eversource Solution Design Committee.

Using the nameplate data with age and ratings combined with the PTX scores, the power transformers noted in Exhibit CLP-TSP-1 at 55 have been identified to proceed with the initial capital project evaluation within the Targeted System Plan. As these evaluations are completed, the power transformers will be prioritized and projects initiated as confirmed. The project sequencing and deferral options will be evaluated within this review.

The two active and ongoing projects for transformer replacements included within the Targeted System Plan followed the processes noted above, were prioritized within the project portfolio, and are planned to be placed in-service in 2028.

Date Filed: September 23, 2026

Witness: John P. DiPaola-Tromba
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 67. Confirm whether Shepaug 13A is approximately 85 years old, has Short-Term and Long-Term Health Index values below 0.5, and is not scheduled for replacement during 2027–2031. Identify each younger transformer scheduled for replacement before Shepaug 13A and provide the specific condition, capacity, safety, or compliance reason supporting that ordering.

Response:

Exhibit CLP-TSP-3, at 67, is correct in the statement that the Shepaug 13A-21X transformer is currently 85 years old. The most recent data from July 2026 indicates Short-Term Health Index of 0.194 and Long-Term Health Index of 0.289.

The statement of "No projects for Shepaug 13A are currently in the 5-year plan" included in Exhibit CLP-TSP-3, at 67, was an error. The Shepaug 13A-21X transformer is one of the transformer asset condition transformer replacement projects within the Targeted System Plan.

There are two active asset condition projects with transformer replacements scheduled prior to the replacement of the Shepaug 13A-21X transformer. CS00286 is a project that includes replacement of the Franklin Drive 1B substation transformers 1B-4X and 1B-5X. This project was established to replace the transformers that were installed in 1953 (73 years old), increase station capacity, and remove an area phase shift. CS00396 is a project that includes the replacement of the Stevenson 14A substation transformer 14A-1X after its failure. This transformer was 83 years old at the time of failure.

Date Filed: September 23, 2026

Witness: David L. Gladey and Lavelle A. Freeman
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3 at 22–24.

a. Provide the data underlying the headroom and constrained-area presentations on pages 22–24. For each substation identified as constrained, provide its normal and emergency rating, five-year historical load and peak load data, available headroom, forecast first year of violation, and proposed project cost.
b. For each constrained substation identified, provide the existing analysis of temporary and permanent load transfers. Identify the receiving substation or feeder, available transfer capacity, MW that could be transferred, required enabling work, estimated cost, and reason any transfer was rejected. Please confirm if no transfer analysis was performed.
c. Provide a summary of each actual substation capacity violation and stranded-load event experienced from 2016 through the present. Identify the substation, date, maximum loading, applicable rating, duration, contingency, customers at risk, customers interrupted, and whether load transfer prevented or reduced an outage.

Response:

a. The graphic depicted in CLP-TSP-3, at 22, is derived from headroom data for substations with actual values, time series data, and ratings shown on our public maps using the, Eversource CT Grid Connection Navigator. Loads are based on our most recent summer peak year, 2025. Please refer to OCC-599, Attachment 1 CONFIDENTIAL, for project forecast violation year and the 5-year historical peak load data for each respective project. The table contains the LCC rating of each substation which is the planning criteria identified within the DSPG, please refer CLF-SC-023, Attachment 1. The following substations have projects initiated and have obtained at a minimum a conceptual level estimate:

Substation	Estimated Project Cost
West Brookfield 14H	$16,900,000
Beacon Falls 11N	$12,632,000
Franklin Drive 1B	$17,986,000
Southington 4C	$9,772,600
Berlin 6A_13.8kV	$23,199,000
Westside 7A	$18,399,000
Hopewell 22R	$17,518,000

All other substations within the attachment have not had a comprehensive evaluation to identify possible solutions and the costs associated with those solutions. The table below depicts a high-level tabletop analysis for possible projected cost of a substation solution. These costs will be refined as these projects progress through the funding process and receive full engineering analysis for solutions and conceptual level estimates.

Substations	**High Level Estimate**	**Project Status**
Waterside 22M	$600,000	Investigating Project Need
Flax Hill 24A	$500,000	Investigating Project Need
Rocky Hill 12Y	Less than $250,000	Investigating Project Need – Anticipating Permanent Load Transfer from West Brookfield 14H with settings changes only
Triangle 11A	$4,800,000	Initial Funding Approved
Middle River 28M	$500,000	Investigating Project Need
Rockville 14W	$10,000,000	Initial Funding Approved
Campville 14R	$52,300,000	Partial Funding
Baldwin 13F	$20,250,000	Initial Funding Submitted
Tracy 14M	$9,900,000	Initial Funding Approved
Frybrook 13B	$20,000,000	Initial Funding Approved
Brooklyn 30Y	Less than $250,000	Investigating Project Need – Anticipating Permanent Load Transfer from Tracy 14M or Frybrook 13B with settings changes only

b. Prior to initiating a funding project, permanent load transfers are, in many cases, a preferred solution if the conditions at the constrained substation and the adjacent area support this as these are typically substantially lower cost than substation investments and have a much more rapid deployment timeline. Historically these load transfers were not explicitly tracked, and the Company does not possess historical data as it pertains to deferrals by means of permanent load transfer. As of 2024 the Company identified this opportunity to begin having a detailed record of load transfers, partly in response to increasingly constrained regional capacity. The Company is now prepared to track these transfers in the Step Load Tracker as a load transfer on the receiving substation and a negative load transfer to the originally constrained station. This tracker will not only allow the forecasted load transfer to be visible but will also allow for historical reporting of deferred major capital upgrades through completed load transfers.

The newly identified projects are in early stages of development and have not yet completed the solution selection process yet. Therefore, these projects would not yet have any tracked load transfers or analyses completed to date. Following initial funding of these projects, all available solutions including permanent load transfers, non-wires solutions, and traditional solutions are identified and evaluated for suitability and for viability. No potential solutions have been rejected at this time from these newly identified projects. Temporary transfers are reserved for substations anticipating overload during a current planned peak event, planned or unplanned outages, or other transient system events. Temporary solutions place the system in an abnormal condition which can impact operations, protections and controls, and automations within the system and are not used as a long-term solution except where necessary to address real-time operational needs that do not have a permanent solution placed into service.

c. All substation forecasted violations are mitigated by using pre-contingent load transfers to adjacent substations with remaining capacity. In accordance with planning criteria in the Distribution System Planning Guide (CLF-SC-023, Attachment 1), the Company plans and designs its system to avoid overload of major substation assets such as transformers during an N-1 event. During real-time operation, these overload scenarios are avoided through the use of monitoring technology and planned mitigation measures. However, the Company's substation planning group recreates a normalized substation load to aid in the process of forecasting for future years.

Date Filed: September 23, 2026

Witness: Lavelle A. Freeman and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3, at 24. Define "stranded load" as used on page 24, including its unit of measurement and the conditions under which load is classified as stranded.

Response:

Stranded load is defined as mega-watts (MW) of load that is at risk of not being restored following a single failure or emergency event until extensive repairs are completed. Customer load will be classified as stranded when a substation's forecasted load exceeds its emergency rating, also referred to as Load Carrying Capacity "LCC".

Exhibit CLP-TSP-3, page 24, and this definition, are limited in scope to substation planning.

Date Filed: September 23, 2026

Witness: Lavelle A. Freeman and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3, at 24. For each year from 2022 through 2026, provide the actual stranded load experienced on the system. For each event, identify the substation, date, stranded MW or MVA, duration, cause, and number of customers whose service could not be restored. If no actual stranded load occurred in a year, please report zero.

Response:

The chart on Exhibit CLP-TSP-3, at 24, refers to a modeled evaluation of the system based on substation load that would not be restored during an N-1 event even after pre-contingent load transfers. In the years identified, there has not been a substation N-1 event that has resulted in stranded load because the substations are designed to handle the event with customers experiencing either no outage or at worst limited to momentary outages during switching or restoration activities. This exhibit highlights, that for the substation in which this risk has been identified it is highly likely that customers will experience an outage related to a transformer failure. The Company's response to information request OCC-603, with an anticipated filing date of September 30, 2026, will provide more detailed information regarding the substation of concern.

Date Filed: September 28, 2026

Witness: Lavelle A. Freeman and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3. For each proposed capacity project, identify every temporary or permanent load transfer evaluated by the Company. Provide the MW available, estimated cost, implementation time, and whether the transfer was accepted or rejected.

a. State whether any evaluated load transfer could eliminate the forecast overload or defer the proposed project. For each such transfer, provide the amount of overload addressed, the resulting revised need date, and the capital investment that could be deferred.

Response:

Temporary Transfers: Refer to OCC-602, Attachment 1 CONFIDENTIAL, for all temporary load transfers evaluated by the Company for the summer of 2026. The temporary load transfer database is evaluated and updated in May of each year using the latest substation forecast available for that given summer peak load. This database identifies the substation or transformer limitation, the forecasted load, and the amount of load required to be transferred. The Company evaluates available feeder ties and load that can be transferred to meet the required need as defined. All temporary transfers are accomplished using DSCADA devices.

Permanent Transfers: Historically the Company has not officially tracked permanent load transfers used to defer substation capacity upgrades; therefore, the permanent load transfers at these substations are not readily available. The Company has recently established a new step load tracking process that also includes load transfers between substations. This new tool was established in 2024 and will not only show future projected load transfers that will feed the substation forecast, but will also keep record of any completed load transfer and the amount of load in kVA. This tool shows both inbound and outbound transfers. Historically, many of these load transfers were handled utilizing settings changes and were low cost, rapid deployment solutions, so the full capital solution process was not required and limits the information that was captured regarding historical changes to the original designed configuration of the substation.

OCC-602, Attachment 2 CONFIDENTIAL, is an export query from the "Step Load Tracker" tool. The query has been filtered to show all completed and potential future permanent load transfers between substations. As noted above, this tool was created to help track permanent load transfers and only identifies load transfers from 2024 and beyond. Please note that not all permanent load transfers identified in this table are due to substation capacity.

In CLP-TSP-3, the Company has included substation projects that would likely require capital project development activity within the ten-year planning horizon. These new substation capacity projects could enable additional load transfers to help alleviate nearby substations. Where possible, these load transfers will be completed by reconfiguring circuits and applying new settings to recloser devices. The changes can be accomplished under annual work orders and do not require major capital projects.

Date Filed: September 28, 2026

Witness: Lavelle A. Freeman and Juan F. Martinez
Request from: Office of Consumer Counsel

Question:

Refer to Exhibit CLP-TSP-3, at 24, figure 'substation violations -statewide',

a For each year shown, state the MW represented by the "Risk of Stranded Load" line. Define "risk of stranded load" and explain how it is calculated. Provide all data, assumptions, calculations, and analyses supporting the values in native, machine-readable format with formulas intact.
b The red line becomes non-zero beginning in 2023. For each value shown from 2023 through the latest historical year, clarify whether it represents actual stranded MW or a modeled estimate of load that could have become stranded. If it is modeled risk, explain why the graph presents a risk estimate rather than actual stranded-load experience for those years.

Response:

a The MW representing "Risk of Stranded Load" within this figure is specifically depicting the constrained area in Western CT, which is identified in Exhibit CLP-TSP-3, at 22-23. The individual substation 10-year forecasts for substations within this area, and already experiencing an overload can also be referred to in OCC-591, Attachment 1 CONFIDENTIAL. To mitigate any substation forecast exceeding 100% of LCC for the most recent summer peak loads, the Company will perform temporary load transfers to adjacent substations if it does not create new loading concerns at the receiving stations. The issue in this region identified through a regional analysis in 2025, is that the adjacent substations do not have adequate capacity to allow enough load to be transferred from the substation listed at OCC-591, Attachment 1 CONFIDENTIAL, at page 1, to keep the remaining transformers below their emergency rating during an N-1 event. Instead, the Company has chosen to disable some auto restoration capabilities within the substation to avoid exceeding transformer emergency ratings. This will result in interruptions for these customers with no planned alternate source. The difference in load between forecasted above emergency limits and what can be transferred is calculated as "Risk of Stranded Load" in MW. Please refer to OCC-602, Attachment 1 CONFIDENTIAL, to see the calculated values for summer of 2026. The remaining values forecasted from 2027-2035 is incremental "Risk of Stranded Load" based on the Triangle 11A forecast presented in OCC-591, Attachment 1 CONFIDENTIAL.

b The Graph represents the risk of stranded load following a contingency condition at the substation. For this substation, the Company has not experienced a single contingency condition during peak load days since 2023, so therefore showing actual stranded load is not applicable. Instead, the Company shows the modeled stranded load which represents the risk to customers during such low probability, high impact events. Due to the severity of these types of events, the Company's planning standard in the DSPG (refer to CLF-SC-023, Attachment 1) is to avoid loss of load (or stranded load) for a single-contingency condition. For this reason, the planning criteria ensure that customers have an alternate supply for a given failure of major equipment, and this stranded load represents those customers that do not currently have a pre-planned alternate feed to supply their needs.